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BEFORE THE ARIZONA CORPORATION COMMISSION

Commissioners

Tom Forese, Chairman
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Andy Tobin, Commissioner
Boyd Dunn, Commissioner
Justin Olson, Commissioner

IN THE MATTER OF RESOURCE PLANNING AND PROCUREMENT IN 2015 AND 2016	DOCKET NO. E-00000V-15-0094

Joint Stakeholder Comments on the Integrated Resource Plans of Arizona Public Service Company (APS) & Tucson Electric Power (TEP): Alternative Portfolios

Joint comments filed by Western Resource Advocates (WRA), Arizona Utility Ratepayer Alliance (AURA), Diné CARE, To Nizhoni Ani, Western Grid Group, Arizona Interfaith Power and Light, Conservative Alliance for Solar Energy (CASE), Tucson 2030 District, Arizona Solar Energy Industries Association (AriSEIA), Efficiency First Arizona, National Association of Energy Service Companies (NAESCO), Solar Energy Industries Association (SEIA), Polyisocyanurate Insulation Manufacturers Association (PIMA), Arizona Community Action Association (ACAA), Southwest Energy Efficiency Project (SWEEP), and Our Mother of Sorrows Catholic Church.

Respectfully submitted this 2nd day of February 2018 by:

Arizona Corporation Commission
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February 2, 2018

Western Resource Advocates (WRA) , Arizona Utility Ratepayer Alliance (AURA), Diné CARE, To Nizhoni Ani, Western Grid Group, Arizona Interfaith Power and Light, Conservative Alliance for Solar Energy (CASE), Tucson 2030 District, Arizona Solar Energy Industries Association (AriSEIA), Efficiency First Arizona, National Association of Energy Service Companies (NAESCO), Solar Energy Industries Association (SEIA), Polyisocyanurate Insulation Manufacturers Association (PIMA), Arizona Community Action Association (ACAA), Southwest Energy Efficiency Project (SWEEP), and Our Mother of Sorrows Catholic Church

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Introduction

The following comments are provided by by Western Resource Advocates (WRA), the Arizona Utility Ratepayer Alliance (AURA), Diné CARE, To Nizhoni Ani, Western Grid Group, Arizona Interfaith Power and Light, the Conservative Alliance for Solar Energy (CASE), the Tucson 2030 District, the Arizona Solar Energy Industries Association (AriSEIA), Efficiency First Arizona, the National Association of Energy Service Companies (NAESCO), the Solar Energy Industries Association (SEIA), the Polyisocyanurate Insulation Manufacturers Association (PIMA), the Arizona Community Action Association (ACAA), the Southwest Energy Efficiency Project (SWEEP), and Our Mother of Sorrows Catholic Church regarding the 2017 Integrated Resource Plans filed by APS and TEP.

regarding the 2017 Integrated Resource Plans filed by APS and TEP.

As several stakeholders have indicated in their comments to this proceeding, the plans that were filed by APS and TEP are biased in favor of natural gas expansion, and biased against other resource options including renewable energy, energy storage, energy efficiency, and demand management. Importantly, we note that these other non-gas resource options are not only preferred by customers but also could lead to less overall cost and risk to customers going forward. As such, we describe here an Alternative Portfolio for both APS and TEP that we believe would provide a better path going forward in terms of meeting customer needs than the portfolios selected by APS and TEP in their 2017 IRPs.

Collectively the Alternative Portfolios would eliminate the need for over 4,520 MW of natural gas additions planned by APS and TEP. They would also put each utility on a path towards approximately 40% renewable energy by 2030, while investing in over 2,530 MW of new energy storage resources, and reducing peak demand by over 2,640 MW through energy efficiency and over 540 MW through demand management and demand response. Moreover, the Alternative Portfolios could save Arizona utility customers over $542 million when compared to the plans selected by APS and TEP.

Given limited budget and time constraints, the analysis presented here does not provide the full suite of technical modeling that could be pursued in developing an IRP. Nevertheless, we believe the analysis presented is sufficient to provide insight into the viability of the Alternative Portfolios and we recommend that they be thoroughly considered. We believe this provides a valuable "proof of concept" for what could be achieved while providing reasonable estimates of the potential costs and operational issues that may be encountered along the way. We welcome further discussion with APS, TEP and the Commission about these alternatives and any additional supporting analysis that may be needed.

Recommendations

As our analysis demonstrates, we believe the Alternative Portfolios presented here each provide a viable option that has many advantages over the portfolios selected by APS and TEP. In order to achieve the outcomes characterized by the Alternative Portfolios, we recommend several steps for the Commission to take:

- Establish a goal for APS and TEP to achieve at least 40% renewable energy by 2032. Include in this goal a set aside for renewable energy projects that provide a benefit to the Navajo and Hopi tribes of at least 300 MW for APS and 160 MW for TEP.

- In the IRP proceeding, require each utility to adopt a near term action plan that includes the following:
    - APS and TEP should each procure, respectively, 270 MW and 250 MW of energy storage by 2022.
    - At a minimum, APS and TEP should each continue to pursue energy efficiency resources at levels achieved in 2016, for each year from 2020 through 2032.
    - APS and TEP should pursue additional energy efficiency measures and advanced demand-management measures (beyond 2016 levels) that are specifically tuned to the evolving load shape (this should not include efforts being pursued through rate design or energy storage).
    - APS and TEP should pursue near-term procurement (by 2022) of a balanced mix of renewable resources including at least 575 MW of wind (375 for APS and 200 MW for TEP), 970 MW of solar PV (700 MW for APS and 270 MW for TEP), and 30 MW of forest biomass for APS.
- Direct the utilities to develop a quantitative assessment of the impact of electric vehicles on system energy needs and needed charging capacity.
- Consider the Alternative Portfolios presented here in any future review of or application for natural gas plant construction or acquisition.

Summary of the Resource Portfolios Selected by APS and TEP in their 2017 IRPs

APS' Selected Portfolio

In its 2017 IRP, APS selected a resource portfolio (the "Flexible Resource Portfolio" or "Selected Portfolio") that includes significant near-term natural gas resource additions, no increase in utility-scale renewable resources, significantly reduced demand-side management efforts, and almost no near-term energy storage resources. Specifically, the plan includes the following:

- Over 5,500 MW of new natural gas resources by 2032. More than 2,400 MW of these gas resource additions occur within the next five years including 1,500 MW of combined cycle additions and over 900 MW of combustion turbine additions.
- No new utility-scale renewable resources except for a small wind contract extension (16 MW-peak) in 2027.
- Peak demand reduction from energy efficiency is scaled back from approximately 100 MW annual incremental savings (or about 1,000 MW over 10 years) to 50 MW annually (or about 500 MW over 10 years).
- Only 3 MW of energy storage added over the next 5 years.

TEP's Selected Portfolio

In its 2017 IRP, TEP selected a resource portfolio (the "Reference Case") that includes significant near-term natural gas resource additions, significantly reduced demand-side management efforts, modest near-term renewable resource additions and modest near-term energy storage resources. Specifically, the plan includes the following additions over the next 15 years:

- Approximately 750 MW of natural gas capacity additions, including 336 MW of RICE units and 412 MW of combined cycle units. 600 MW of these additions occur within the next five years.
- Over 700 MW of new renewable resource capacity by 2032, including 100 MW of wind and 80 MW of utility-scale solar added within the next five years.
- Peak demand reduction from energy efficiency is scaled back from approximately 36 MW annual incremental savings (or about 360 MW over 10 years) to only 9 MW annually (or about 90 MW over 10 years).
- 100 MW of energy storage additions, with 50 MW occurring within five years.

In both cases, the utilities have selected portfolios that significantly expand natural gas resources in the near term. Meanwhile, both utilities significantly scale back their energy efficiency efforts relative to current levels, resulting in less energy savings and less peak demand savings going forward relative to current efforts. APS adds no meaningful new utility-scale renewable resources. In TEP's case, significant renewable energy resource additions are included, enabling 30% renewable energy by 2030.[1] However, most of these additions do not occur until much later in the planning horizon (i.e. after 2023). Both portfolios include meaningful energy storage resources; however, in APS' case most of these additions do not occur until after 2024.

We recognize that APS and TEP studied additional portfolios as part of their IRP analysis. However, we find that these other portfolios are not meaningfully different in terms of the expansion of natural gas resources. For example, the chart below illustrates that all seven of the portfolios analyzed by APS contain identical additions of natural gas combined cycle units (except for one minor change to one portfolio in the final year). Similarly, TEP did not appear to defer any gas generation resource additions in the portfolios that contained alternative resources.

[1] Figure according to TEP; the 30% renewable level may apply only to renewables' share of retail sales, not the full system generation.

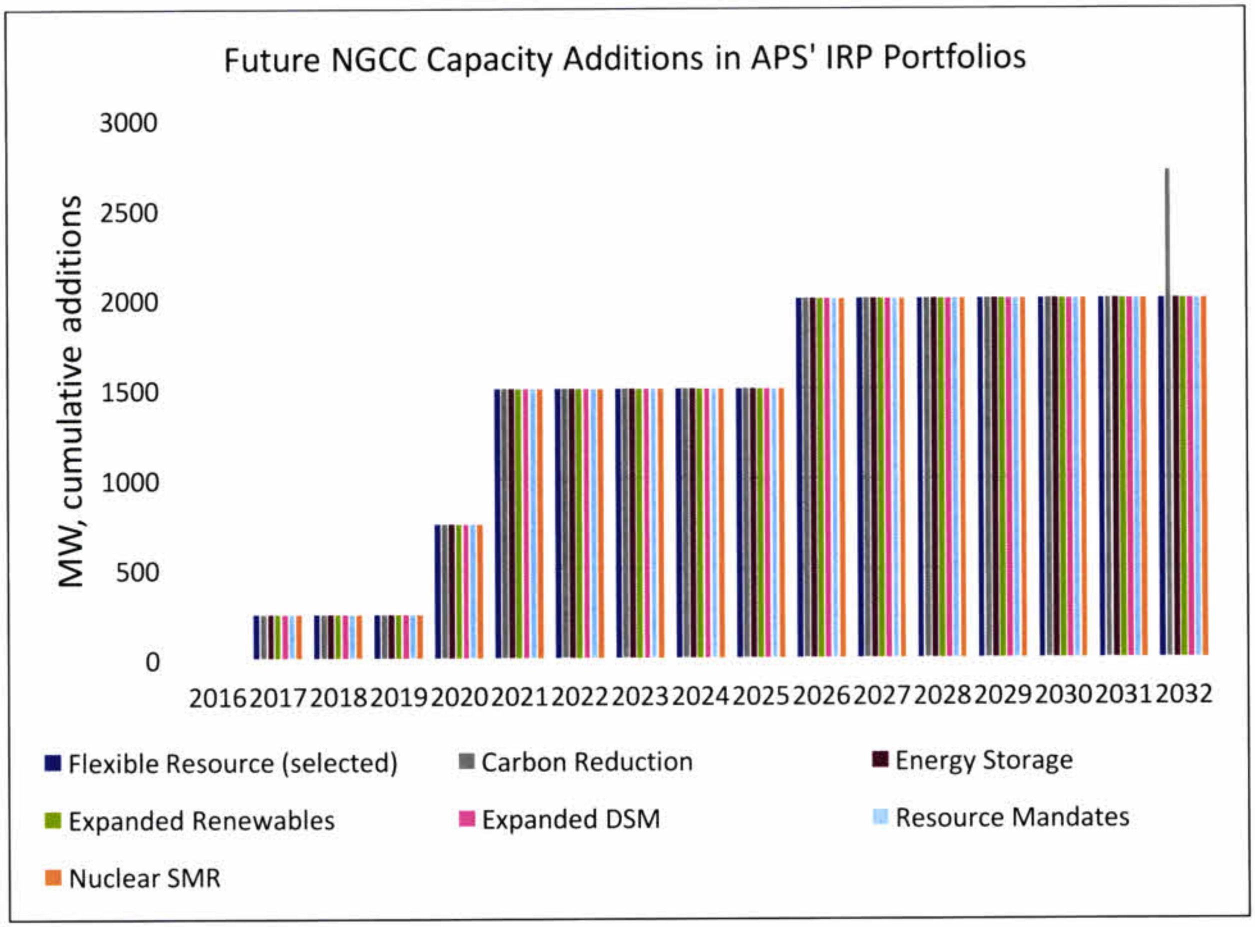


Figure 1. Comparison of NGCC capacity additions in portfolios analyzed in APS' IRP. Data source: APS 2017 IRP, Attachment F.1(A)(1) through F.1(A)(7).

Both portfolios appear to emphasize near-term natural gas resource additions instead of a combination of renewables, energy storage, and demand-side management. We do not believe this emphasis on natural gas matches customer preferences, moreover it represents a substantial increase in cost and risk borne by customers due to the uncertainty of future fuel commodity prices and the fact that fuel costs (and associated price risk) are directly passed through to customers. To better match customer preferences for clean energy and to better manage the cost and risk associated with natural gas additions, we developed an Alternative Portfolio for both APS and TEP for the Commission's consideration. These Alternative Portfolios are the result of a detailed analysis of the information provided in the APS and TEP IRPs, with specific modifications as described below.

Summary of the Proposed Alternative Portfolios for APS and TEP

APS Alternative Portfolio Summary

The APS Alternative Portfolio would reduce the addition of new natural gas resources over the next 5 years from over 2,400 MW to just 510 MW.[2] Over the long-term it would eliminate the need for over 3,875 MW of new natural gas additions when compared to APS' Selected Portfolio. In place of these gas additions, the Alternative Portfolio would include the following new resource additions:

- 1,105 MW of new large-scale renewable energy resources over the next 5 years, ultimately reaching more than 3,000 MW of new renewables by 2032. The near term additions would include 375 MW of wind, 700 MW of solar PV, and 30 MW of biomass. By 2032 wind additions would reach 1,105 MW and solar additions would reach 1,920 MW.
- New energy storage resources totaling 270 MW over the next 5 years and 2,100 MW by 2032.
- Incremental energy efficiency resources totaling 723 MW of cumulative peak demand reduction over the next 5 years and nearly 1,970 MW by 2032.
- Incremental new demand response and demand management resources totaling 168 MW over the next 5 years and over 450 MW by 2032.

As a result of these changes and others described herein we estimate that the total revenue requirement (net present value) for the APS Alternative Portfolio would be over $275 M less costly to customers over the 15-year period than the portfolio selected by APS.

Additionally, we estimate that the Alternative Portfolio would meet basic peak demand (MW) and energy (MWh) needs in each year of the planning horizon. We also estimate that the Alternative Portfolio would provide sufficient flexible ramping capability on APS' system to meet the maximum ramp events expected to occur in each year through 2032. Overgeneration events would continue to occur on a limited number of low load days throughout the year but could be managed through a combination of energy storage, modest renewable resource curtailment, and continued participation in regional markets.

[2] The remaining 510 MW consists of the Ocotillo Modernization Project, which we presumed was too advanced at this stage to be avoided.

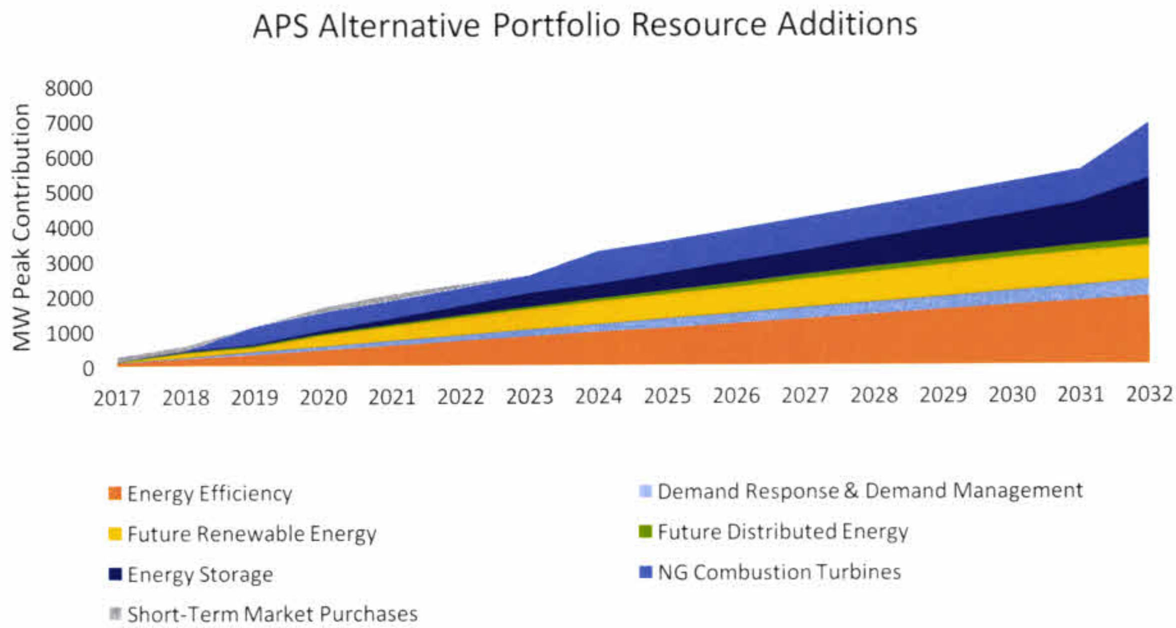


Figure 2. Capacity additions included in the APS Alternative Portfolio by MW-peak contributions.

Resource Additions (MW nameplate, incremental)	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2017 - 2022 Total**	**2017 - 2032 Total**
NG Combined Cycle	0	0	0	0	0	0	**0**	**0**
NG Combustion Turbine	0	0	510	0	0	0	**510**	**1,600**
Energy Efficiency	98	125	125	125	125	125	**723**	**1,973**
Demand Response	18	30	30	30	30	30	**168**	**466**
Wind (nameplate)	0	75	75	75	75	75	**375**	**1,920**
Solar PV (nameplate)	0	140	0	280	140	140	**700**	**1,834**
Energy Storage	0	45	0	50	75	100	**270**	**3,200**

Table 1. Near-term resource additions in the Alternative Portfolio for APS

TEP Alternative Portfolio Summary

The TEP Alternative Portfolio would reduce the addition of new natural gas resources over the next five years from over 600 MW to 100 MW. Over the long-term it would eliminate the need for approximately 650 MW of new natural gas additions when compared to TEP's Reference Case. One 100 MW RICE unit addition included in the Reference Case would be delayed from 2020 until 2022 while other RICE units and combined cycle resource additions would be eliminated. In place of these gas additions, the Alternative Portfolio would include the following new resource additions:

- 470 MW of new large-scale renewable energy resources over the next 5 years, reaching over 1,125 MW of new renewables by 2032.
- New energy storage resources totaling 250 MW over the next 5 years and over 430 MW by 2032.
- Incremental energy efficiency resources totaling 225 MW of cumulative peak demand reduction over the next 5 years and 675 MW by 2032.
- Incremental new demand response and demand management resources totaling 30 MW over the next 5 years (above existing levels) and 90 MW by 2032.

As a result of these changes and others described herein we estimate that the total revenue requirement (net present value) for the Alternative Portfolio would be $268 M less over the 15-year period than the portfolio selected by TEP.

Additionally, we estimate that the Alternative Portfolio would meet basic peak demand (MW) and energy (MWh) needs in each year of the planning horizon.

We estimate that the Alternative Portfolio would provide sufficient flexible ramping capability on TEP's system to meet the maximum 10-minute ramping events through 2024. Additional analysis may be needed to assess 10-minute ramping needs over the long term.

Due to time and resource constraints we were unable to analyze any overgeneration issues on TEP's system. However, we believe TEP will be able to employ strategies similar to those we describe for APS to manage this, including energy storage, renewable resource curtailment, and regional market participation.

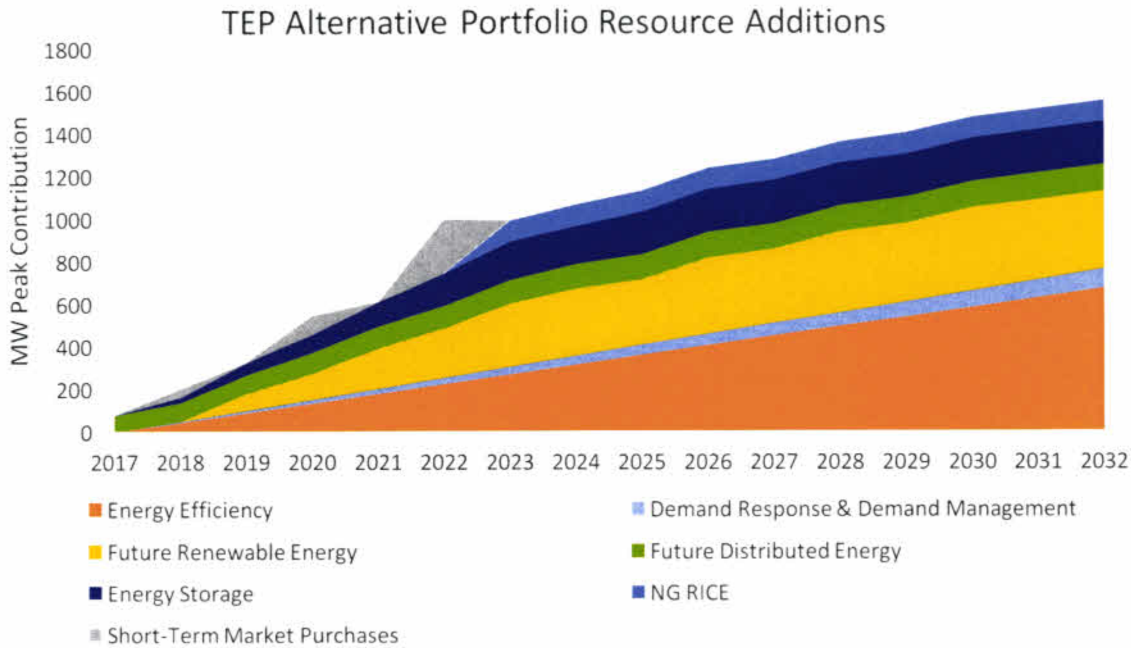


Figure 3. Capacity additions included in the TEP Alternative Portfolio by MW-peak contributions.

Resource Additions (MW nameplate, incremental)	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2017-2022 Total**
Natural Gas Combined Cycle	+0	+0	+0	+0	+0	+0	+0
Natural Gas RICE	+0	+0	+0	+0	+0	+100	+100
Incremental DSM (MW)	+0	+45	+45	+45	+45	+45	+225
Incremental DR (MW)	+0	+6	+6	+6	+6	+6	+30
Incremental Wind (nameplate)	+0	+50	+50	+0	+100	+0	+200
Incremental Solar PV (nameplate)	+0	+40	+50	+50	+50	+80	+270
Incremental Storage	+0	+25	+0	+90	+45	+90	+250

Table 2. Near-term resource additions in the Alternative Portfolio for TEP

Portfolio Construction

In each case, the development of the Alternative Portfolios began by using the Selected Portfolio or Reference Case Portfolio developed by APS and TEP as a starting point. We relied on the same energy and peak demand forecasts as those developed in the utility portfolios. We also relied on the same forecasts for distributed energy included in the utility portfolios.

We then removed or delayed several of the natural gas plant additions proposed in these portfolios. For APS, one exception to this was the 510 MW combustion turbine addition associated with the Ocotillo Modernization Project. Since this project is already at a very advanced stage, we presumed it could not be significantly altered. For TEP we delayed the addition of the first 100 MW of RICE units to 2022.

Next, sufficient additional resources were included to ensure that the portfolios met both annual peak demand (MW) needs and annual energy (MWh) needs for each year through 2032. To ensure a reasonable buildout, we limited additions of certain resources to a finite amount in each year. For example, wind additions were limited to no more than 100 MW in a single year for each utility. Several additional timing adjustments were also made, included the following:

- Extended one tolling agreement for APS.[3]
- Extended the PacifiCorp/APS diversity exchange.[4]
- Modified short term market purchases within 5 years.[5]
- Retired Cholla Generating Station in 2024 and Four Corners Generating Station in 2031.[6]

For existing thermal units, energy output was initially set to match the capacity factors modeled in the Selected Portfolios. Adjustments were then made to the energy ouptut from certain thermal units based on overall energy needs. In most years, this led to a reduction in output, reflecting the fact that additional energy efficiency and renewable resources will likely lead to reduced overall energy need from thermal generation in some years, thereby yielding additional fuel cost savings (or potential off-system sales).

Detailed load and resource tables and energy mixes are presented in Appendices A & B.

[3] Similar to the method employed by APS in construction of its Selected Portfolio.
[4] See: https://www.azcentral.com/story/money/business/2014/09/11/aps-plans-close-one-four-generators-cholla-power-plant/15455255/
[5] Assumes short-term capacity purchase price of $50/kW-yr.
[6] Similar to TEP's Reference Case and APS' Coal Reduction Portfolio.

Table 3. Comparison of Key Assumptions in APS' Selected Portfolio and the Alternative Portfolio

Load/Resource Assumptions	**APS Selected Portfolio**	**Alternative Portfolio**
Load Forecast	50% increase by 2032	Same as APS Selected Portfolio
Renewable Energy	No new resources (except for one small wind contract extension)	1,105 MW of new wind 1,920 MW of new solar PV (SAT) 30 MW of forest biomass
Distributed Energy	200 MW/year of DG added	Same as APS Selected Portfolio
Energy Storage	3 MW by 2022; 397 MW by 2032	270 MW by 2022; 2,104 MW by 2032;
Energy Efficiency	Reduction from current program levels of 50 MW/year	Increase from current program levels of 25 MW/year
Demand Response/Demand Management	Increase of 25 MW/year starting in 2021	Increase of 30 MW/year starting immediately
Existing Coal	Navajo retires in 2020 Cholla retires in 2025	Navajo retires in 2020 Cholla retires in 2024 Four Corners retires in 2031
Tolling/Exchanges	Extends one tolling agreement	Extends two tolling agreements Extends PAC diversity exchange
Natural Gas Combined Cycle (NGCC)	1,500 MW added by 2022 2,000 MW added by 2032	No NGCC additions
Natural Gas Combustion Turbine	941 MW added by 2022 3,516 MW added by 2032	510 MW added by 2022 1,641 added by 2032

Table 4. Comparison of Key Assumptions in TEP's Reference Case and the Alternative Portfolio

Load/Resource Assumptions	TEP Reference Case	Alternative Portfolio
Load Forecast	Annual growth rate of ~1%	Same as TEP Selected Portfolio
Renewable Energy	100 MW new wind by 2022 325 MW new wind by 2032 80 MW new solar by 2022 450 MW new solar by 2032	200 MW new wind by 2022 525 MW new wind by 2032 240 MW new solar by 2022 600 MW new solar by 2032
Distributed Energy	128 MW-peak by 2032	Same as TEP Reference Case
Energy Storage	55 MW by 2022 105 MW by 2032	250 MW by 2022; 515 MW by 2032;
Energy Efficiency	Reduction from current program levels of 20 MW/year	Increase from current program levels of 9 MW/year
Demand Response/Demand Management	Increase of 3 MW/year	Increase of 6 MW/year
Existing Fossil	Navajo retires in 2020 Four Corners retires in 2031 San Juan Unit 1 retires in 2022 Sundt Units 1, 2, & 3 retire in 2020, 2022, and 2030	Navajo retires in 2020 Four Corners retires in 2031 San Juan Unit 1 retires in 2022 Sundt Units 1, 2, & 3 retire in 2020, 2022, and 2030
Natural Gas Combined Cycle (NGCC)	412 MW added by 2022	No NGCC additions
Natural Gas RICE	192 MW added by 2022 336 MW added by 2032	100 MW added by 2022

Renewable Energy Resource Additions

Additional renewable energy resources were included in the Alternative Portfolios beyond what has been proposed by APS and TEP. Specifically, for APS we propose adding 375 MW of new wind resources and 700 MW of new large-scale solar resources over the next five years, and over 3,055 MW (nameplate) of new large-scale renewable resources by 2032. We estimate this would contribute nearly 1000 MW towards meeting APS' peak demand requirements in 2032. Additionally, as discussed below, some of these resources could be paired with storage to provide additional capacity benefits.

For TEP we propose a similar buildout of renewables as TEP's selected Reference Case, however these resource additions would be accelerated to occur primarily before 2023 rather than after that year. In addition, after 2023, 200 MW of wind and 150 MW of solar would be added.

For distributed resources we incorporated the same projections of customer adoption included in APS and TEP's plans. We recognize that these projections could change, particularly in light of recent decisions affecting net metering and retail rate structures that may reduce deployment of rooftop solar going forward. In this case, there would be a reduced risk of overgeneration and ramping constraints under both the Selected and Alternative Portfolios.

Overall, we estimate that these additions would result in renewable energy (including distributed energy) accounting for approximately 40% of APS' and TEP's energy mix by 2030.

We believe APS and TEP's underutilization of renewable energy resources is due, in part, to using unreasonably high price assumptions for renewable resources. The prices in APS' resource plan, in particular, do not reflect the low prices of solar and wind that we have seen in recent RFPs and executed PPAs. In the alternative portfolios, new renewable energy resource costs were estimated based upon on recent PPA purchase prices in the region. For instance, solar PV PPA prices in Nevada, Colorado, and Arizona have recently been reported in the $29-35/MWh range.[7] Notably, in the Nevada case, there was no escalator applied to the PPA price of $34/MWh. Wind PPA prices for projects in New Mexico have recently been reported in the $18-20/MWh range.[8] Even if additional transmission costs are necessary to deliver this wind energy to Arizona, we find that wind resources would still be competitive.[9] Based on this knowledge we assumed a PPA price of $40/MWh for wind and $34/MWh for solar PV in the 2018 timeframe. For comparison, APS assumes a levelized cost of $158/MWh for wind and $58/MWh for solar PV (tracking), for installations in 2020. TEP assumes a levelized cost of $53/MWh for wind and $44/MWh for solar PV (tracking) for installations in 2018 (Table 5).

Table 5. Comparison of recent renewable energy PPA prices to renewable resource costs used by APS and TEP in their IRPs.

	Recent PPA or RFP Prices[10]	APS Modeled Costs	TEP Modeled Costs
Utility-Scale Solar PV (SAT)	• $31 – 34/MWh (NV Energy, 2017) • $29.50/MWh, median price (Xcel Energy (Colorado), 2017 RFP)	$58/MWh	$44/MWh
Wind	$19/MWh (Southwestern Public Service Co., Sagamore project, eastern New Mexico, 2017)	$158/MWh	$53/MWh

Additionally, wind and solar technologies were assumed to decline in cost at a rate of 1% and 2% per year respectively. Furthermore, we assumed prices for new wind and solar projects were adjusted over

[7] See for example the following recent announcements:

- https://pv-magazine-usa.com/2017/11/09/nv-energy-seeks-approval-for-31-34mwh-solar-ppas/
- https://www.utilitydive.com/news/xcel-solicitation-returns-incredible-renewable-energy-storage-bids/514287/
- https://www.utilitydive.com/news/updated-tucson-electric-signs-solar-storage-ppa-for-less-than-45kwh/443293/

[8] https://www.xcelenergy.com/staticfiles/xe-responsive/Company/Rates%20&%20Regulations/Regulatory%20Filings/NM-Filings-David-T-%20Hudson-NM-Direct.pdf

[9] Recent analysis by NREL has estimated incremental transmission costs for wind energy in the region to be approximately $22/MWh, based on the SunZia project: https://www.nrel.gov/docs/fy17osti/66506.pdf

[10] Solar prices predate the solar tariff announcement

time to account for the phase out of federal tax credits as well as new trade tariffs imposed on solar PV modules beginning in 2018.[11]

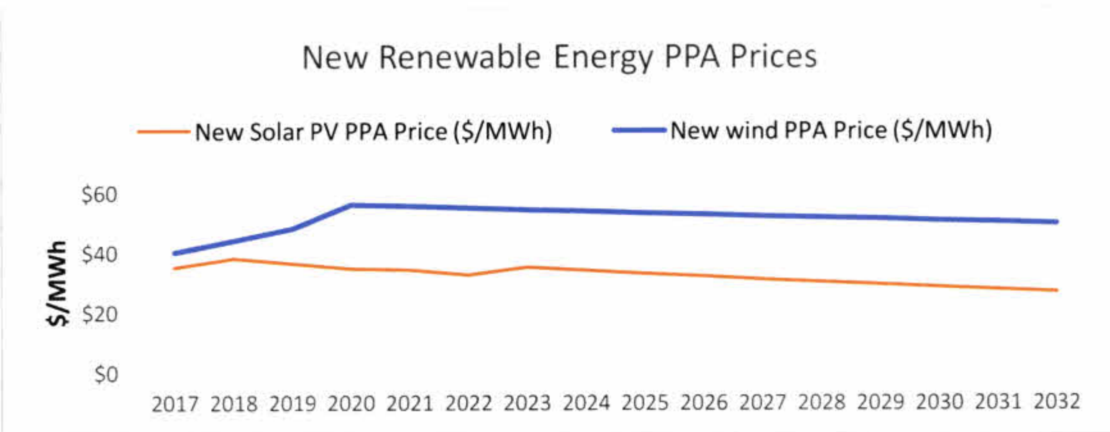


Table 6. New renewable resource costs assumptions used in developing the Alternative Portfolios. Solar and wind PPA prices are based on recent public announcements and are adjusted for phase out of federal tax credits (PTC/ITC) as well as recent Section 201 trade tariffs.

Hourly energy output profiles for wind and solar PV resources were developed using the System Advisor Model, using representative data for Arizona and New Mexico. These profiles were used to calculate net load for analyzing ramping and overgeneration issues on an hourly basis for APS.

Although renewable resources are intermittent they still provide a capacity contribution to the system that is less than their nameplate values. Both APS and TEP include assumptions for the peak-coincident capacity contributions of wind and solar PV resources.

Table 7. Comparison of capacity values for renewable resources used by APS and TEP.

Resource Type	**Capacity Value (peak coincidence)**
TEP Plan:	
Solar PV – Fixed	34%
Solar PV – Tracking	65%
Wind	23%
APS Plan:	
Solar PV - Fixed	10-50%
Solar PV – Tracking	40-73%
Wind	18-20%

[11] Analysis by Marathon Capital has shown that the likely impact of the Section 201 trade tariffs is likely to be on the order of 10-12% in 2018 (see https://www.marathon-cap.com/news/impact-of-section-201-import-tariffs-on-utility-scale-solar-lcoe). This impact will be reduced in later years as the tariffs phase down and would not apply to projects where PV modules were procured in advance, projects using modules that qualify for the 2.5 GW exemption, or projects using module technologies that are not affected by the Section 201 tariffs. Additionally, the impact will likely be dampened in high insolation regions such as Arizona due to higher output relative to initial module costs.

For solar resources, we assume installations are predominately grid-scale tracking systems with an initial capacity value of 65%, which is consistent with the value provide by TEP and the range provided by APS. However, as APS notes, "capacity values are subject to change and vary with existing levels of penetration." Thus, the capacity value for solar PV was steadily adjusted down over time to reflect the reduced capacity contribution of solar PV as penetration increases, ultimately reaching the lower end of the range provided by APS. It should be noted that coupling renewable energy resources with even a modest amount of energy storage may be a cost-effective way to limit this decline in capacity value. Notably, the median bid price received in Colorado for over 10,000 MW of proposed solar PV plus storage projects was $36/MWh, compared to our initial PV only cost of $35/MWh. Since our initial PV cost is somewhat conservative relative to recently announced prices, it may be possible to assume that most of the future solar PV projects could include a storage component. For wind we assumed capacity values reported by APS and TEP respectively. For solar resources we assumed annual output (capacity factor) consistent with TEP's plan and resources on APS' system. For wind resources we assumed annual output (capacity factor) similar to the recently proposed projects in New Mexico.

Navajo and Hopi Energy Resources

Arizona's economy has depended on tribal energy for decades through the use of power from Navajo Generating Station both for direct energy consumption and for pumping water to Phoenix and Tucson. In turn these communities have depended on the economy created by the Navajo Generating Station. While we agree that the plant is no longer economic and should be closed in 2020 as currently planned, we are supportive of a continued interdependence between the tribes and the broader Arizona community in terms of their shared energy economy.

Both APS and TEP are part owners of Navajo Generating Station (NGS), owning 315 MW and 168 MW respectively. Each utility also has access to a corresponding amount of transmission from the plant that could be repurposed for other resources developed in the vicinity of NGS. As such, a corresponding portion of the renewable resources in each Alternative Portfolio could be specified for projects developed in part to provide a continued benefit stream to the tribal communities. This corresponds to roughly 10-20% of the nameplate capacity of renewable resource additions proposed in each Alternative Portfolio. We believe the Commission should consider establishing a tribal renewable resource target as a means to help ensure this outcome.

Energy Storage Resource Additions

The Alternative Portfolios include significant new additions of energy storage resources beyond what APS and TEP included in their plans. These resources are included both to help meet peak demand and to help meet operational challenges associated with daytime overgeneration and evening ramping as solar penetration increases. Beyond these function, the energy storage systems can also provide economic value through energy arbitrage, by charging from the grid during times when energy is inexpensive, and discharging when it is more expensive. They may also provide fast ramping capabilities and frequency regulation.

The storage facilities were assumed to be 4-hour battery energy storage facilities. For APS we assumed the addition of 270 MW of battery energy storage facilities over the next five years, reaching over 2,104 MW by 2032. For TEP we assumed the addition of 250 MW of battery energy storage facilities over the next five years, reaching over 430 MW by 2032

Energy storage costs were based on Lazard's most recent Levelized Cost of Storage study, released in 2017.[12] This report estimates a levelized cost of storage equal to $395/kW-yr for a 4-hour duration lithium-ion battery used for peaker plant replacement (including financing). This is based on an estimated capital cost of $1,338/kW for a battery system installed in 2017.

For comparison, APS assumes a capital cost of $1,539/kW for a 4-hour Li-ion battery storage system installed in 2020. TEP assumes a construction cost of $2,568/kW (duration unspecified) for a Li-ion battery storage system installed in 2018. For reference, Xcel Energy's recent RFP received bids for over 1,600 MW of stand-alone battery storage, with a median price of $11.30/kW-month, which, if available year-round, translates to $136/kW-yr.[13]

We estimate a 2% annual cost decline for new energy storage resources, which is consistent with the forecast provided in the Lazard study. In general, our analysis assessed the addition of standalone storage resources. However, we are well aware that storage systems are increasingly being paired with renewable resource additions which offers many potential synergies. For example, storage systems primarily charged from solar PV can take advantage of the federal investment tax credits, as well as enhanced performance via DC-coupling. Storage can also enhance the capacity value of wind and solar by increasing dispatchability during peak hours, and reducing intermittency. These hybrid systems are also increasingly cost competitive. A solicitation recently conducted by Xcel Energy in Colorado received bids for over 10,000 MW of solar PV with battery storage projects, with a median bid price of $36/MWh. It also received over 5,000 MW of wind plus battery storage projects, with a median bid price of $21/MWh.

Energy Efficiency, Demand Response, and Demand Management Resource Additions:

For the APS Alternative Portfolio we initially included the energy efficiency and demand response resource additions included in the High DSM Portfolio developed by APS. We note that this portfolio generally reflects a continuation of APS' recent demand-side management efforts in each year of the plan. For example, APS achieved approximately 100 MW of peak demand savings and 517 GWh of energy savings from energy efficiency in 2016, which is the approximate amount of peak demand and energy savings achieved each year under APS' High DSM Portfolio. For TEP, we also initially included energy efficiency resources consistent with recent efforts. More specifically, TEP achieved 36 MW of peak demand savings and 159 GWh of energy savings from energy efficiency in 2016. For both utilities, additional energy efficiency measures were added beyond this "current trajectory" that were tailored to

[12] https://www.lazard.com/perspective/levelized-cost-of-storage-2017/

[13] Public Service Company of Colorado, December 28, 2017. 2016 Electric Resource Plan, 2017 All Source Solicitation 30-Day Report (Public Version).

meet the specific needs of the utilities' evolving load profiles. For APS, an additional 25 MW of annual incremental energy efficiency was added, yielding a total of 125 MW of annual incremental peak demand savings from energy efficiency. For TEP, an additional 9 MW of annual incremental energy efficiency was added, yielding a total of 45 MW of annual incremental peak demand savings from energy efficiency.[14]

Energy efficiency resource costs were estimated based on APS and TEP's 2016 DSM portfolios. In 2016, APS demonstrated incremental first-year costs of $133/MWh ($12/MWh lifetime) and TEP demonstrated first-year costs of $114/MWh ($10/MWh lifetime). Costs for procuring incremental energy efficiency were assumed to increase from 2016 levels at a rate of 3% annually, and were presumed to be expensed during the year they were implemented.

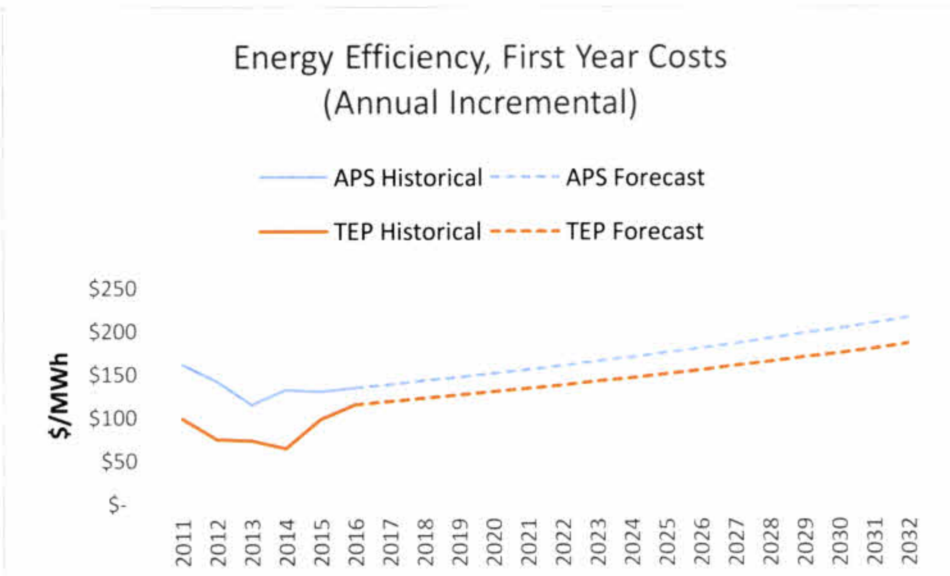
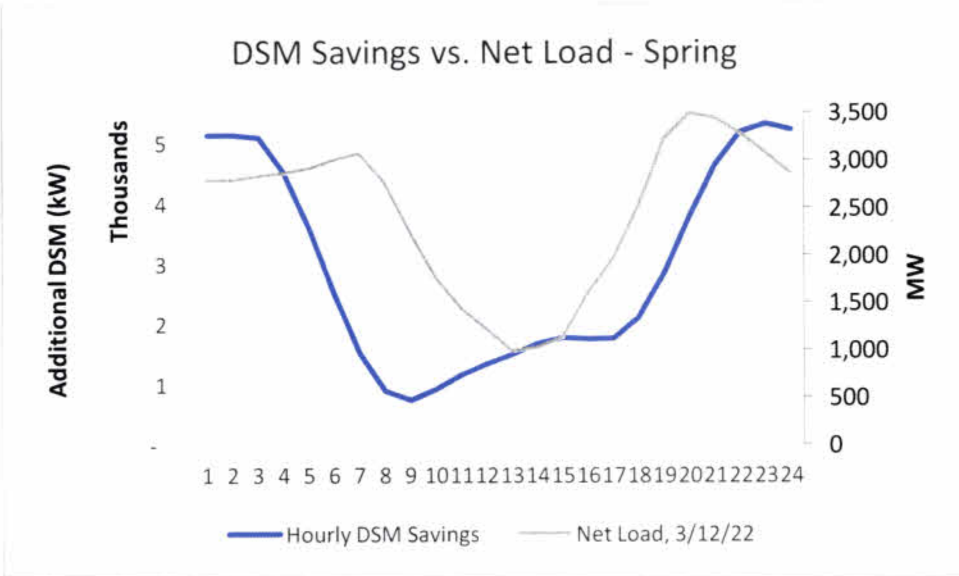


Figure 4. Portfolio costs for implementing demand-side management (DSM) programs included in the Alternative Portfolios.

The net load impact from the additional measures (e.g. the 25 MW for APS above the High DSM Portfolio) was estimated based on a proxy portfolio specifically designed to align with the utilities' evolving system needs. More specifically, measures were selected that maximize peak demand savings in summer months while minimizing savings during daylight hours in the spring months (when solar generation is prominent). The proxy measures found to achieve this effect consist primarily of residential cooling measures, commercial cooling measures, and commercial exterior lighting measures. The charts below illustrate a comparison of the incremental DSM measures to the APS net load profile during both spring and summer months. As these charts indicate, the DSM portfolio is well matched to the system needs across multiple seasons.

[14] Since these incremental measures are more targeted to MW peak savings, we assumed a proportionately lower overall GWh savings than other measures included in the portfolio.



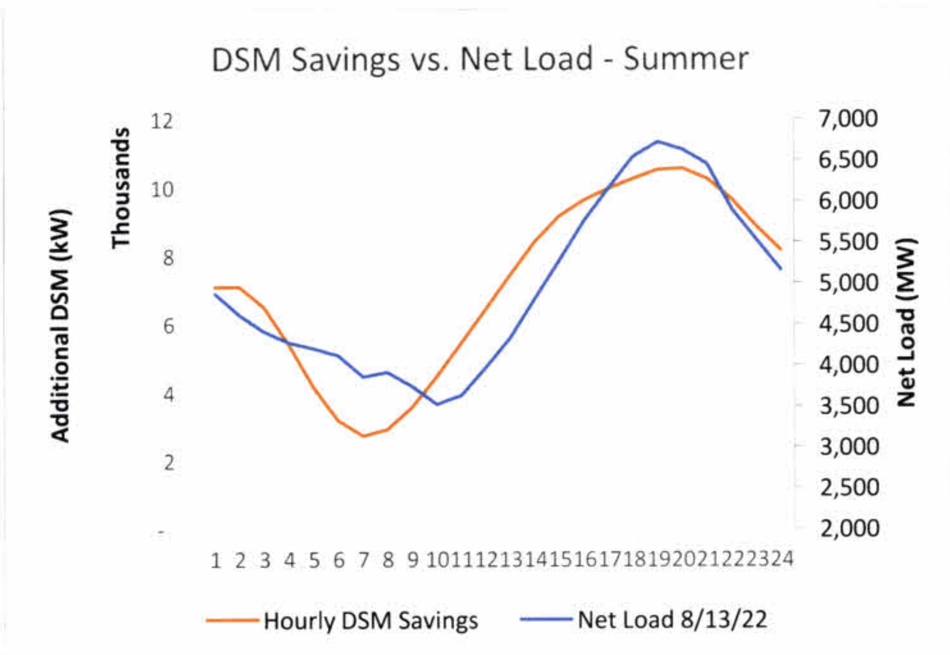


Figure 5. Comparison of APS' forecasted net load in spring and summer months to the savings achieved through the incremental DSM resources included in the Alternative Portfolios.

Both the APS Selected Portfolio and TEP Reference Case include additional demand response. For APS, 25 MW of annual incremental demand response are added in each year starting in 2021, reaching 300 MW by 2032. We included this same portfolio of DR resources that APS included but accelerated procurement to begin in 2018 (rather than waiting until 2021). In addition to conventional demand response, we also included an additional 5 MW of annual incremental demand management savings in each year. Thus the total demand response and demand management savings reach 30 MW of annual incremental savings in each year. For TEP we included the demand response included in the Reference

Case, which averages 3 MW/yr of incremental new resource additions. We also included an additional 3 MW/yr of new demand management savings in each year.

These additional demand management resource additions reflect the potential to achieve new types of demand savings through advanced demand control technologies and automation that were previously unavailable. Advanced demand management programs have been implemented by utilities in the region, but have yet to be scaled up in Arizona. For example, NV Energy has implemented a Residential Demand Response program that enables the utility to temporarily interact with a participating customer's end-use loads on hot summer days in exchange for an incentive and enabling technology. In 2015, NV Energy increased participation levels by 28 MW for a total of 180 MW of residential DR. The total cost to implement this program in 2015 was $11.2 M or about $62/kW. For comparison, APS' Peak Solutions DR program costs were approximately $67/kW in 2016 and TEP's C&I Direct Load Control program costs were approximately $16/kW.

In 2017, NV Energy use of automation and agreements with customers resulted in over 60 direct load control "events" using thermostats, without much customer override. Many of these automated "events" did not take place during peak periods. These NV Energy results are based on new, expanded views of what the opportunities of demand management are, and challenge a common notion that utilities and customers can only manage around 6-8 events a year.

Based on the cost and performance of demand management programs in Nevada we think there is significant potential to scale up similar cost-effective demand management programs in Arizona (in fact, our assumptions may be conservative in this regard). For the Alternative Portfolio, the cost for the incremental demand response and demand management was estimated based on the cost to procure demand response as reported in APS' 2016 DSM plan, escalated at a rate of 3% annually.

Cost Analysis

We evaluated the Alternative Portfolios for their impact in terms of overall cost to customers relative to the utilities' Selected Portfolios.[15] While some of the changes made in developing the Alternative Portfolios led to increased costs due to incremental resource additions, other changes let to substantial cost savings to customers. Notably, cost savings in the Alternative Portfolios were achieved from the following: 1) avoidance of new natural gas additions and 2) reduced fuel and operating costs at existing fossil resources (or increased off-system sales). The net impact of these changes is summarized in the table below. The net present value of customer savings for the Alternative Portfolios were computed using a discount rate of 7.5%.

[15] We recognize that federal tax legislation passed in December 2017 may have an impact on overall utility resource portfolio costs. We did not attempt to account for this in our analysis since the effects are still being determined. We believe the comparison presented here is sound, even if more nuanced tax rate analysis would change costs for all portfolios (both Alternative and Selected).

Table 8. and Table 9. Estimated difference in revenue requirements between the APS and TEP Alternative Portfolios and the APS and TEP Selected Portfolios.

APS Alternative Portfolio - Change Relative to Selected Portfolio	Revenue Requirement, $ millions (NPV, 2017-2032)
Avoided New Natural Gas Costs	($3,511)
Additional Avoided Fuel Costs	($531)
Incremental RE, ES & DSM Resource Costs	$3,766
Total Increase (Decrease) vs Selected Portfolio	($275)

TEP Alternative Portfolio - Change Relative to Selected Portfolio	Revenue Requirement, $ millions (NPV, 2017-2032)
Avoided New Natural Gas Costs	($973)
Additional Avoided Fuel Costs	($144)
Incremental New Resource Costs	$850
Total Increase (Decrease) vs Selected Portfolio	($268)

The avoided costs of deferred new natural gas additions were readily determined from the estimated revenue requirements for these resources provided by APS and TEP. This does not account for additional incremental new pipeline costs which may also be significant.

Additional avoided fuel costs under the Alternative Portfolios were also estimated. To do so, we first determined the total annual energy production (in MWh) from both new and existing resources based on information provided by APS and TEP and the assumptions described in previous sections. Next we determined the annual MWh load obligation, after accounting for energy efficiency and distributed generation. The initial MWh supply of the Alternative Portfolio was generally found to exceed the load obligation in most years. Thus, we assumed that the output at certain existing generators could be reduced, yielding corresponding savings in fuel and O&M. We adjusted the output of specific existing generators and estimated the fuel cost savings based on generator-specific assumptions provided by the utilities.

As noted previously, TEP's Reference Case shows more energy generated (in annual MWh) than is necessary to serve its load in each year. Our understanding is that this difference between energy generated and load is attributable to a significant amount of off-system sales anticipated by TEP. Thus, we took into account the effect of potentially reduced off-system sales when calculating the reduction in fuel costs.

We recognize that a full production cost simulation would be more precise way of quantifying the fuel cost savings from existing resources, however, this was not possible given the limited time and resources available. Nevertheless, we believe this method provides a reasonable first order approximation of the savings achievable through the Alternative Portfolio.

Additional costs for renewable energy, energy storage, energy efficiency, and demand response were only calculated for the incremental resources procured above the Selected/Reference Case portfolios. In this sense, we believe our estimates of these costs are conservative. That is, the total savings from pursuing the Alternative Portfolio may be even greater since some of these resource types are already included in the Selected/Reference Case but appear to be less costly than what APS and TEP have assumed.

Key Performance Metrics

The Alternative Portfolios reflect a more diverse energy mix, and reduce emissions of air pollutants and water use. This reduces utilities' and customers' risk exposure to rising fuel prices or environmental regulations.

Arizona Public Service

Under APS' Selected Portfolio, the utility would be reliant on natural gas to meet approximately 40% of energy demands in 2032, and 66% of peak load; under the Alternative Portfolio, 28% of APS' energy needs are met with natural gas[16], 22% is met through enhanced energy efficiency efforts, 18% of demand is met with nuclear resources, and 32% of demand is met with renewables (both utility scale and distributed generation). If energy efficiency is excluded from the mix, the portfolio meets an equivalent of a 40% renewable portfolio standard. Figure 6 illustrates the energy mix for APS' selected portfolio and the Alternative Portfolio.

The diversified fuel mix has important implications for carbon emissions and water use. The Alternative Portfolio reduces APS' carbon emissions, reducing the potential cost of complying with future federal carbon regulation (Figure 7). In its IRP, APS models a carbon price of $15/metric ton, beginning in 2023. If these carbon prices are applied, the value of the avoided carbon emissions in the Alternative Portfolio is estimated at approximately $300 million (NPV).[17]

Similarly, expected water use under the Alternative Portfolio declines steadily. By 2032, total water use in the Alternative Portfolio is 20% (10,000 acre-feet) less than water use in 2017. For reference, if not used for power generation, that volume of water could meet the household consumptive needs of over 100,000 people for a year. In contrast, water use for power generation grows under the Selected Portfolio (Figure 8).[18]

[16] We assume the energy from market purchases and exchanges is likely generated at natural gas plants.

[17] Assumes a discount rate of 7.5%.

[18] Data from IRP, Attachment F.1(b)(5). Water use for the Alternative Portfolio is based on data in the IRP (Attachment D.3) and EIA Form 923 (2016).

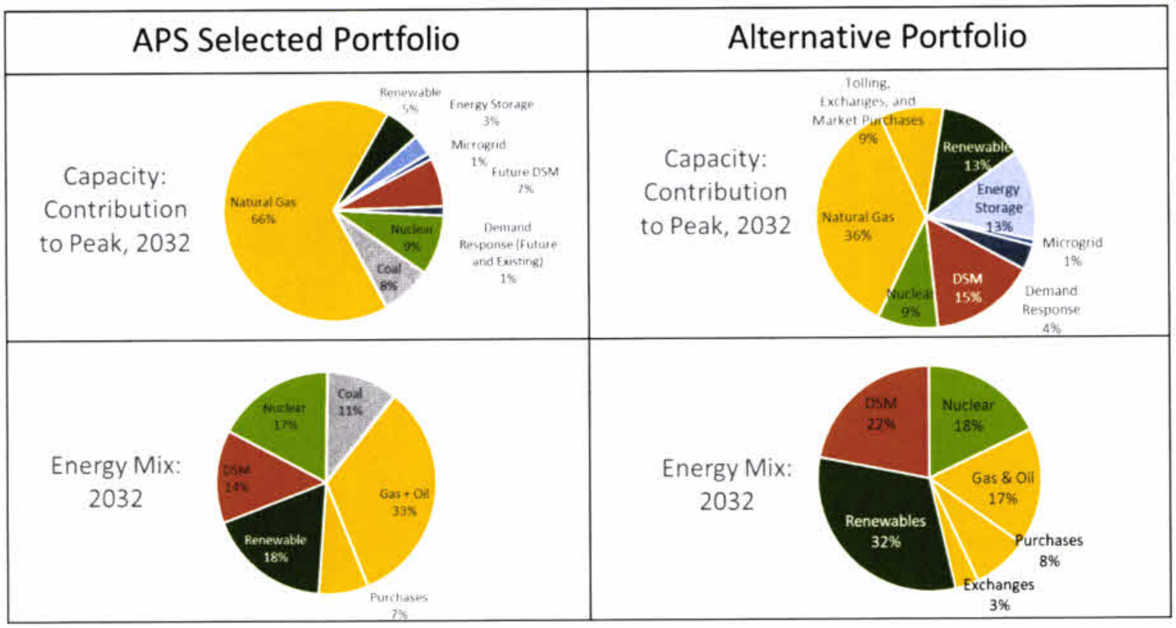


Figure 6. Graph shows the peak capacity and energy mix for APS' Selected Portfolio and the Alternative Portfolio.

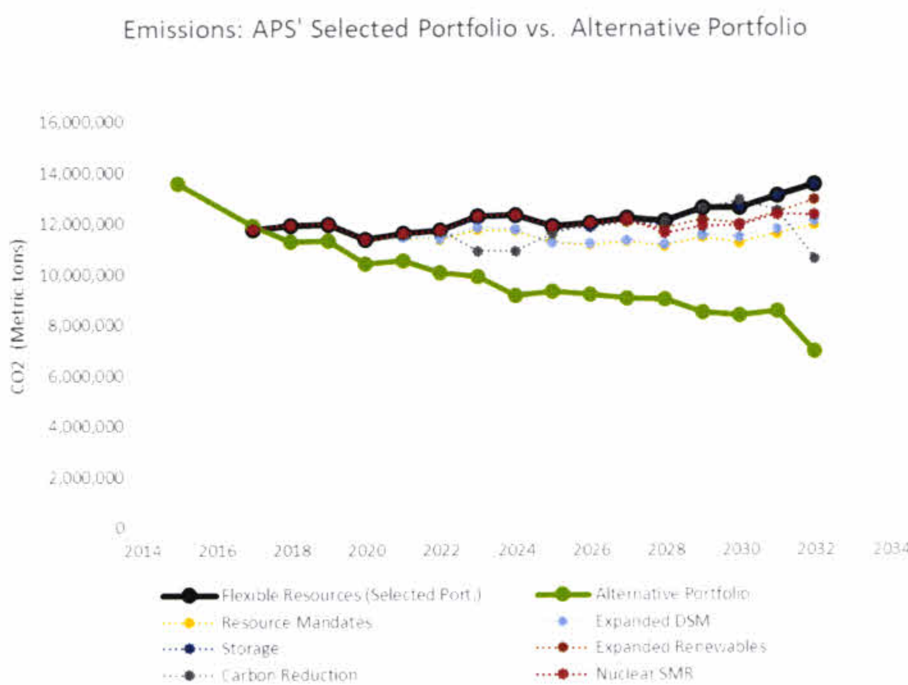


Figure 7. Carbon emissions grow under APS' Selected Portfolio, while they decline steadily under the Alternative Portfolio. The other portfolios evaluated in APS' resource plan are included for reference, and illustrate the small variability in emissions among the seven portfolios.

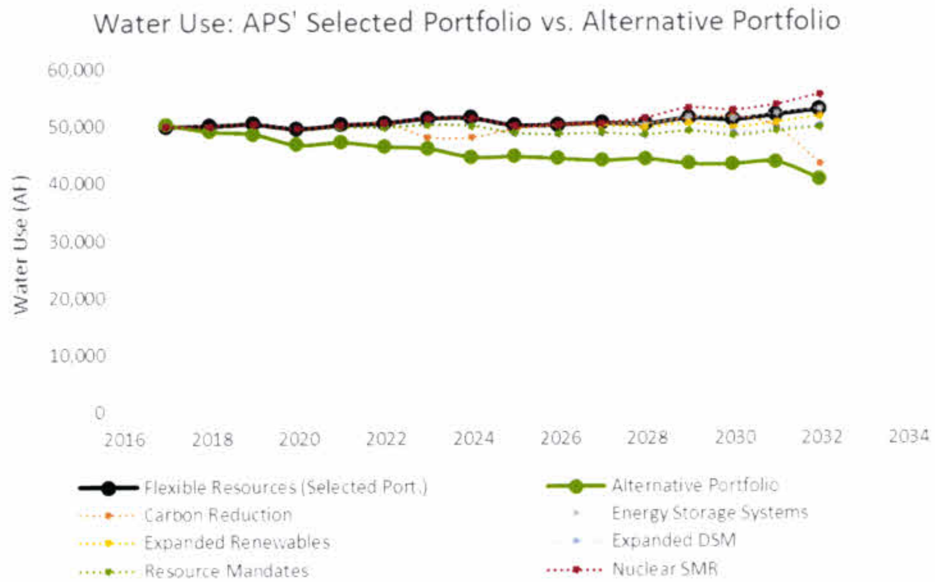


Figure 8. Total water use rises under APS' Selected Portfolio, while it declines steadily under the Alternative Portfolio.

Tucson Electric Power

The Alternative Portfolio represents a more diverse fuel mix, and reduces carbon emissions and water use associated with TEP's load. The Alternative Portfolio differs in several key ways from TEP's Selected Portfolio. Under the Alternative Portfolio, the renewable capacity added generally matches that in TEP's Selected Portfolio; however, this capacity it is added early in the period, rather than delayed until the mid-2020s. In addition, 200 MW of wind and 150 MW of solar are added in the latter portion of the 15-year planning period. Battery storage and energy efficiency resources displace the proposed natural gas resources, reducing total natural gas burn in the Alternative Portfolio.

Under TEP's Selected Portfolio, the utility appears to assume a significant amount of off-system sales due to the fact that the total generation (in GWh) reported in the plan exceeds the utility's load requirements. This excess would be even greater due to energy savings achieved through expanded energy efficiency as contemplated in the Alternative Portfolio. In the Alternative Portfolio, we reduce that excess generation, primarily by reducing output at fossil fuel plants. Whereas under TEP's selected portfolio, renewables (including both utility-scale and distributed PV) represent approximately 20% of the total energy needs (including wholesale sales)[19] in 2032, under the Alternative Portfolio, renewables account for 36% of the energy mix (or 41% of total supply-side resources). Energy efficiency meets a larger portion of demand, and natural gas and coal represent smaller portions of the total energy mix (Figure 9).

To estimate the carbon emissions of the Selected Portfolio and the Alternative Portfolio, we calculate the carbon emissions associated with all of TEP's energy generation, and then adjust those emissions to reflect only TEP customers' share (roughly 67% of the total emissions).[20] As shown in Figure 10, under

[19] Estimated from IRP Chart 53, which includes all generation.

[20] This analysis assumes the off-system sales are the average energy mix of coal, renewables, and natural gas.

the Alternative Portfolio, emissions decline more rapidly than under TEP's Selected Portfolio, and are roughly 36% lower in 2032 than in 2017. Water used for power generation declines under both TEP's Selected Portfolio and the Alternative Portfolio, but there is a more significant reduction under the Alternative Portfolio, due to the displacement of fossil resources with higher levels of energy efficiency and renewables (Figure 11).

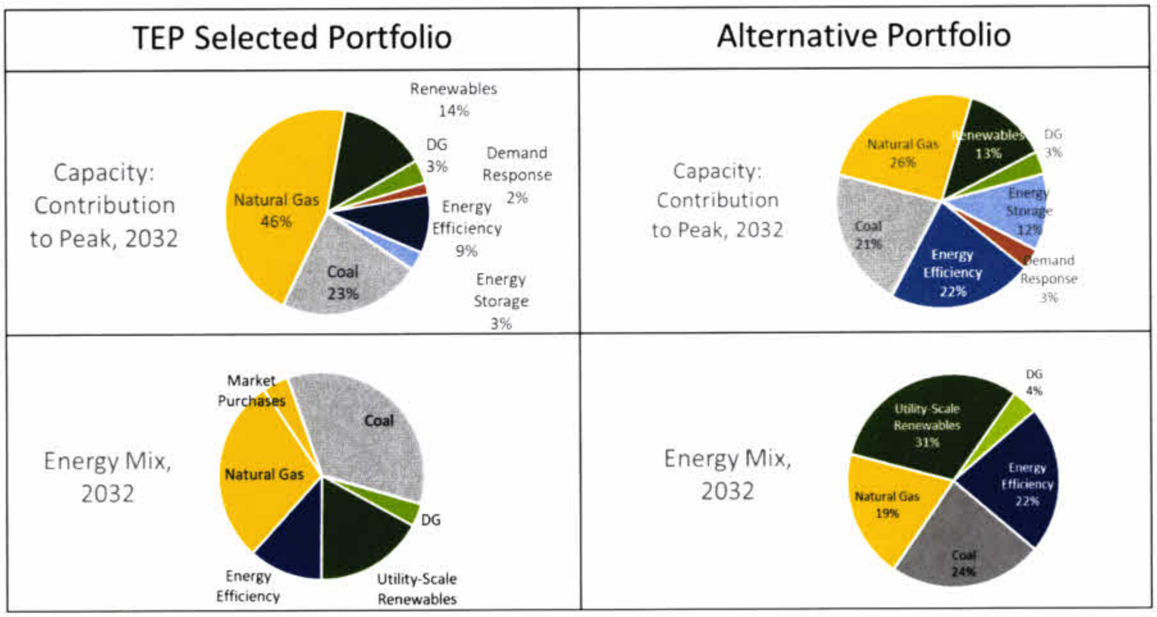


Figure 9. Graphs show peak capacity and energy mixes for TEP's Selected Portfolio and the Alternative Portfolio.

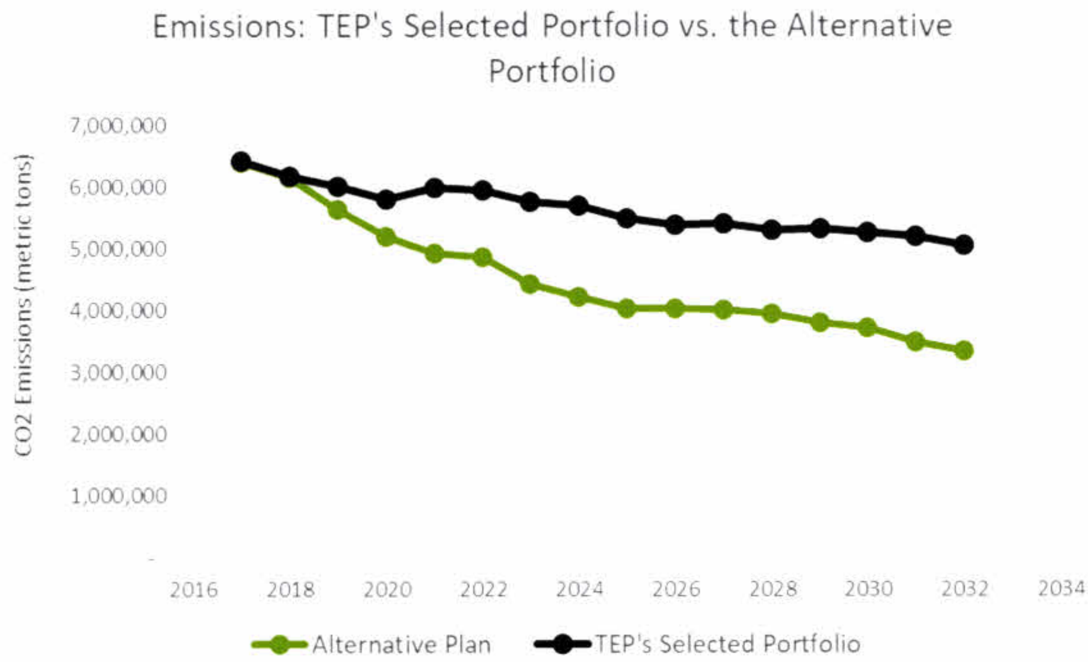


Figure 10. Estimated carbon emissions associated with TEP's load. Note that these emissions are lower than those reported in TEP's IRP, because they are adjusted to reflect emissions associated with TEP's native load, and exclude off-system sales.

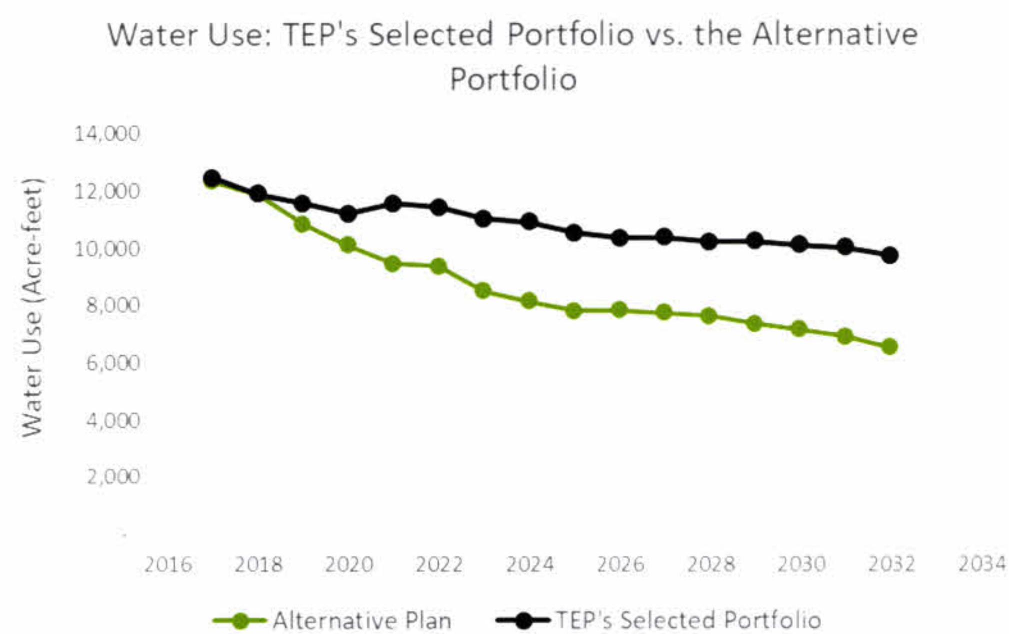


Figure 11. Estimated water use for TEP's native loads under the Selected Portfolio and the Alternative Plan. The Alternative Plan provides almost 4,000 acre-feet of water savings in 2032.

Operational Issues

Beyond meeting peak demand and energy needs, we recognize that the increased penetration of renewable energy is leading to new system challenges. For example, flexible ramping resources may be needed to accommodate certain ramping events, such as when solar PV generation declines in the evening. Additionally, the abundance of solar energy during midday in certain low-load months may lead to overgeneration events in which there is more renewable energy being generated than the system can accommodate. In particular, APS operates the Palo Verde Nuclear Generating Station which consists of inflexible steam units that cannot be ramped down below a certain minimum operating level. Coal units are also relatively inflexible but can still accommodate some amount of cycling. While we think there are many effective strategies for addressing these issues, it is important to study them to better understand when and where they could become significant.

As such, we conducted a preliminary analysis of the overgeneration and ramping issues on APS' system under the Alternative Portfolio using 8760 load and renewable resource data. We also considered these issues for TEP's portfolio, and have conducted a high-level assessment of ramping needs, but have not yet completed the same level of analysis due to time and resource constraints.

The highlights of this analysis are provided below. Beyond this high-level assessment, we recognize that a more detailed modeling effort using production cost simulations could be valuable in better understanding these operational challenges. We would be eager to collaborate with APS and TEP on conducting such modeling exercises to understand the overall annual and multiyear impact on system cost and reliability.

Overgeneration

We assessed the overgeneration issue by calculating the 8760-hourly load and net load (including the impact of large-scale wind and solar) on the system and comparing this to the Palo Verde minimum operating capacity on APS' system (1146 MW). We find that overgeneration events occur on several days throughout the year, but are still relatively infrequent over the course of the year and are most severe in spring months (e.g. April). The addition of energy storage serves to partially alleviate this problem, particularly for overgeneration caused by distributed energy resources that is not curtailable. Large-scale renewables can also be curtailed to help further address the problem. Below is an example of one of the most challenging days in 2032 illustrating how the system could be operated through a combination of energy storage and renewable resource curtailment. Note that this is an extreme case that occurs far into the future, but still appears to be manageable. On an annual basis, we estimate that curtailment of large-scale renewable energy output (in MWh) could reach approximately 6% by 2025. We recommend additional steps to further reduce the amount of curtailment:

- Encourage or require dispatchable capabilities for future distributed generation resources.
- Target electric vehicle load towards daytime load through work-place, school bus, and freight vehicle charging programs.
- Identify opportunities for off-system sales, or market participation, particularly with trading partners in the northern part of WECC that may not have abundant solar resources.

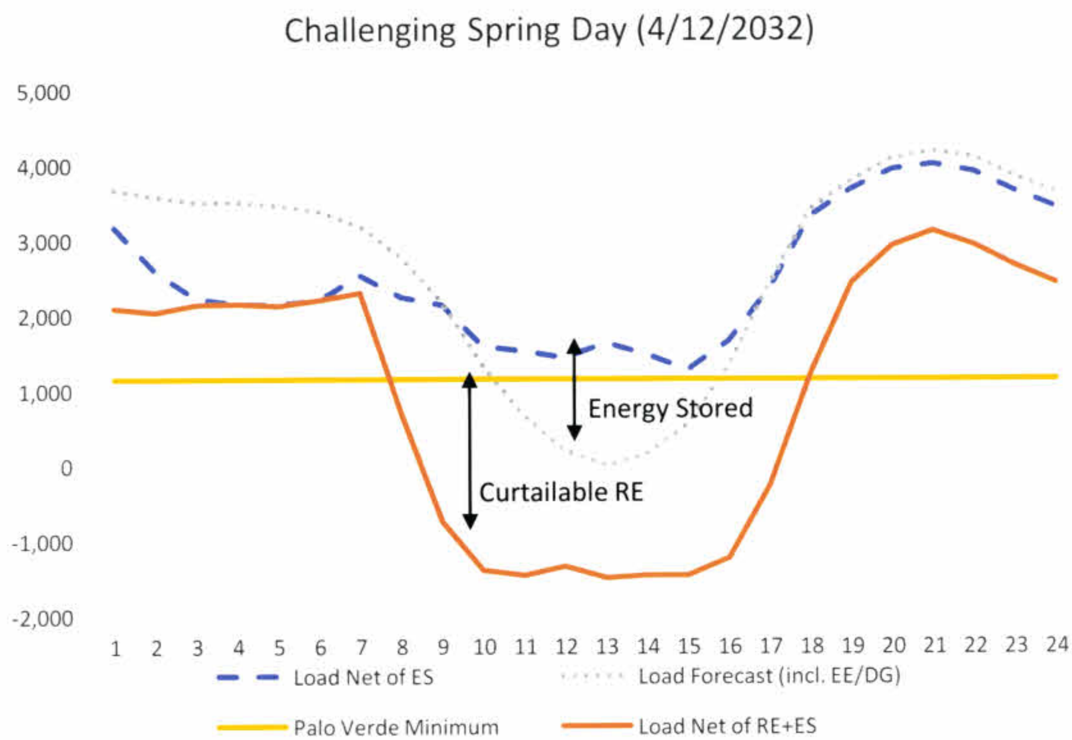


Figure 12. Illustration of one of the most challenging days for overgeneration analyzed in 2032. In this case, a combination of battery storage and renewable resource curtailment can prevent overgeneration from affecting the minimum operating level of the Palo Verde Generating Station.

During summer months, overgeneration is not an issue on APS' system.

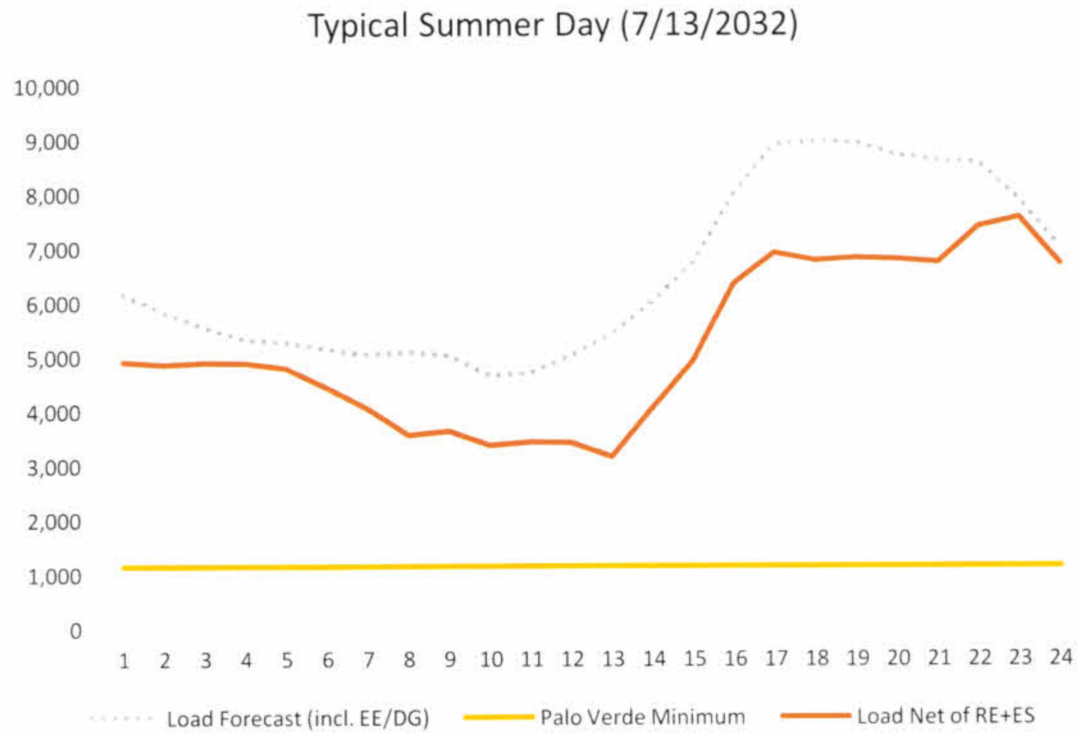


Figure 13. Illustration of the net load for a summer day. As this illustrates, for many months of the year, overgeneration is not a concern.

Ramping

Both APS and TEP describe flexible ramping as a significant future challenge for operating their systems. In particular, TEP notes increasingly significant 10-minute ramping needs going forward and provided an analysis of its ability to meet these needs going forward.

The following chart details the ramping need and capability on TEP's system in 2024 under the Reference Case. We note that under the "Base Case" or "Geographically Dispersed RE" case analyzed by TEP, there is an excess of approximately 250-280 MW of ramping resources. Even under the worst case (i.e. "Geographically Concentrated RE"), and the removal of Sundt Units 3 & 4 there is still an excess of approximately 100 MW. Based on this analysis we believe it may be prudent to delay the addition of some of the proposed new RICE units in order to avoid excess procurement of ramping resources.

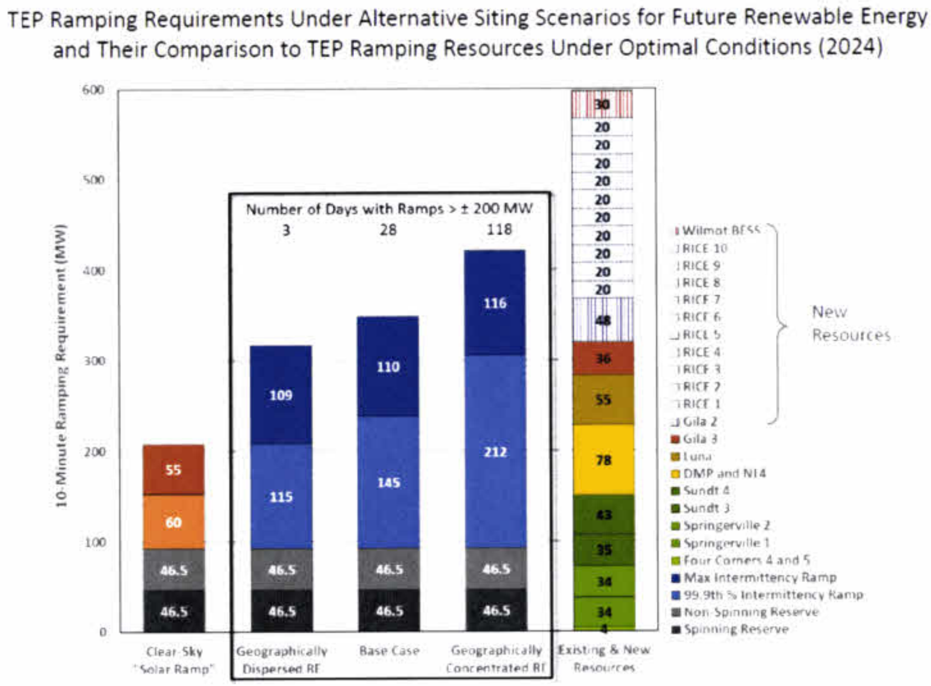


Figure 14. TEP's analysis of 10-minute ramping needs under various renewable energy scenarios. Source: TEP presentation at the Fall 2017 Joint CREPC-WIRAB Meeting, October 16, 2017. http://westernenergyboard.org/wp-content/uploads/2017/10/10-17-17-crepc-wirab-alter-energy-storage.pdf

Under the Alternative Portfolio, since significant energy storage and ramp-reducing DSM resources are added in earlier years, we assume the first RICE unit addition could be delayed from 2020 to 2022. The reduced need for RICE units is further illustrated below:

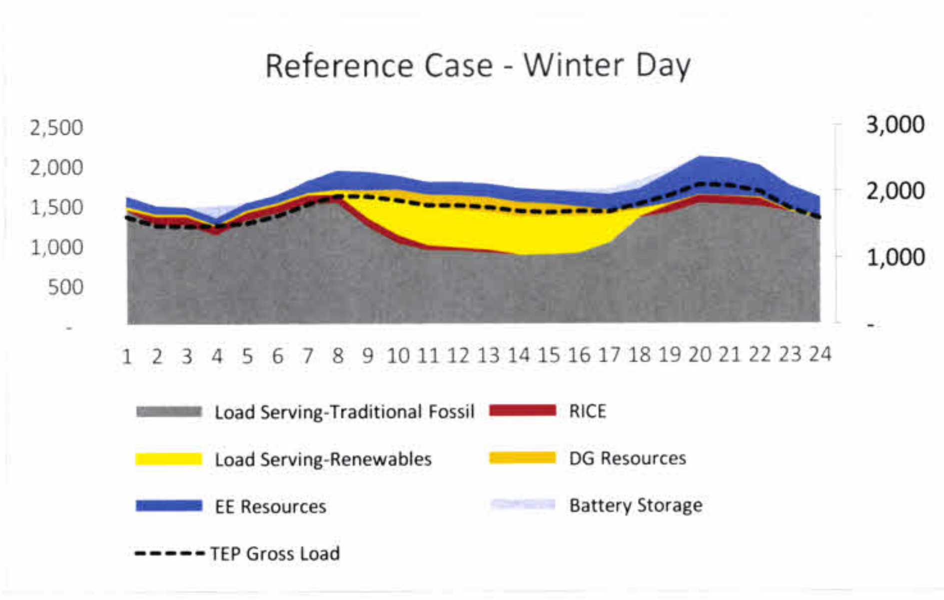


Figure 15. Illustration of load-serving, load-modifying, and grid balancing resources under TEP's Reference Case (replicating TEP's analysis in Chart 19 of their plan).

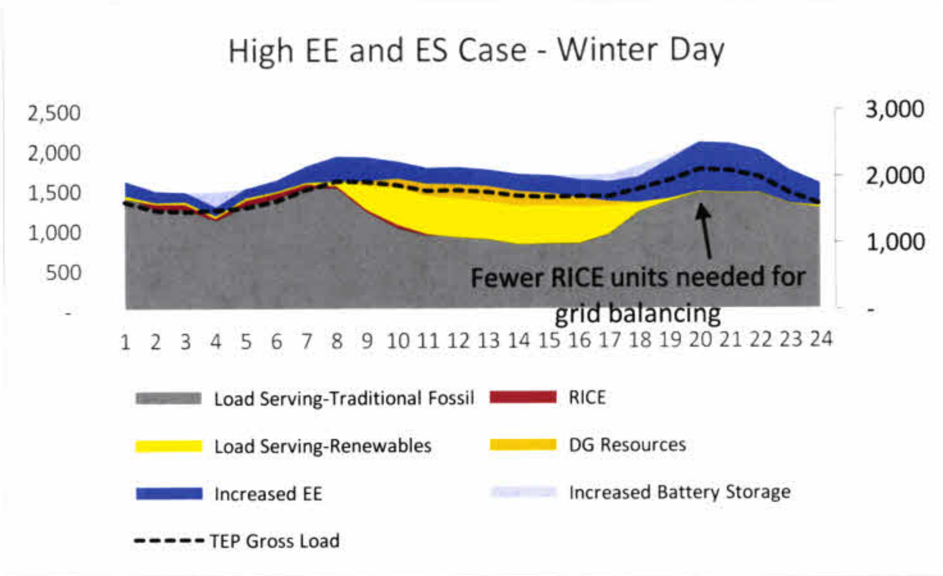


Figure 16. Illustration of the reduction in grid balancing resources that are needed under a portfolio that includes a higher amount of energy efficiency and energy storage (such as the Alternative Portfolio).

Under TEP's Reference Case, a total of approximately 250 MW of grid balancing resources (192 MW of RICE units and 55 MW of energy storage) are added to provide ramping capabilities while delivering 30% renewable energy in 2030. Under the Alternative Portfolio, we have accelerated the procurement of these same renewable resources (325 MW wind and 450 MW solar PV) to occur by 2024. Within the same timeframe, an equivalent 250 MW of grid balancing energy storage resources to provide grid balancing services, in addition to the 100 MWs of RICE units. Additional energy storage is also added in later years corresponding with additions of solar PV resources. Further study may be needed to ensure sufficient 10-minute ramping beyond 2024.

APS did not provide a quantitative assessment of its flexible ramping needs and capabilities in its IRP, but did provide quantitative information in response to a data request. In response to this request, APS provided estimates of the ramping capabilities of new and existing generators in terms of MW/min. It also provided estimates of future 1-hour and 3-hour ramping needs while noting that projections of its 10-minute ramping needs were unavailable. We chose to analyze 3-hour ramping needs since this is a common metric that has been used in recent years by the California ISO to assess flexible resource adequacy. To assess the performance of the Alternative Portfolio, we calculated the maximum 3-hour ramp in each year based on hourly net load. In addition, we estimated the ramping capability on the system from both existing and new resources. The 3-hour ramping capability was estimated based on the ramp rates for each resource type provided by APS in response to a data request and the capacity of each resource type on APS' system under the Alternative Portfolio.[21] The chart below summarizes the ramping needs versus the capability on APS' system under the Alternative Portfolio. We note that there are sufficient ramping resources to meet APS' needs in each year under the Alternative Portfolio.

[21] In cases where a range of ramp rates was provided, we selected the mid-point of this range

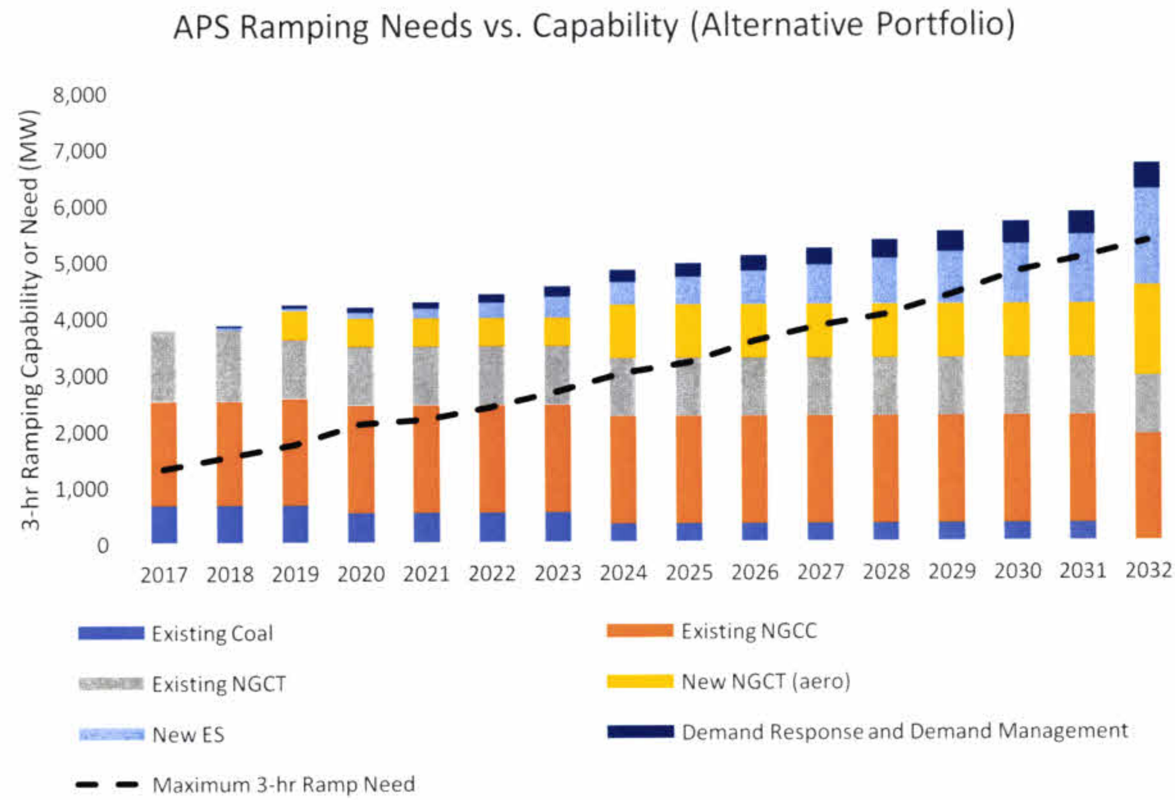


Figure 17. Comparison of APS 3-hour ramping needs and ramping capabilities over the 15-year planning horizon under the Alternative Plan.

Voltage

We recognize that part of the justification for building certain natural gas units such as the RICE units proposed by TEP (and previously the Ocotillo project proposed by APS) is to ensure the system has sufficient voltage support within a specific local area. Since we have removed several of these units it may be necessary to provide location-specific voltage control using other technologies. As such, in the TEP portfolio, we also included the cost of adding 200 Mvar of synchronous condensers and/or capacitor banks, which are also capable of providing local voltage support. According to the NREL Distribution System Upgrade Unit Cost Database, the unit cost of a capacitor bank ranges from approximately $26-61/kVar. Recent estimates of the cost of a synchronous condenser range from $10-40/kVar.[22] Assuming an average cost of $40/kVar, we estimate the cost of these 200 MVar of voltage support additions to be approximately $8 million.

[22] See: http://ieeexplore.ieee.org/iel7/7527139/7539405/07539450.pdf

Electric Vehicles

While electric vehicles (EVs) are still a small percentage of the vehicle fleet, the adoption rates have increased rapidly in recent years. With declines in battery prices, improvements in technology, and manufacturers' plans to deliver additional electric vehicle models, EV sales are expected to continue rising. And in Arizona, Governor Ducey's commitment to advancing electric vehicle innovation through the Intermountain West Electric Vehicle Corridor[23] will help accelerate EV adoption in the state. Electric vehicles will increase total energy demands, but can provide a number of benefits, including air quality and public health benefits from reducing emissions of NOx and CO2, as well as electric grid benefits. As TEP noted in its IRP, well-timed EV charging could take advantage of mid-day solar resources, thereby helping to address overgeneration concerns. Off-peak charging can take advantage of under-utilized utility resources, reducing overall customer costs.

The effect of electric vehicles on utility infrastructure is still uncertain; however, it is critical that utilities evaluate the demands and the potential benefits in a quantitative manner. Various utility and academic studies[24] have evaluated key EV issues, including the number, type, and distribution of EV charging stations; charging energy demands and impact on peak demands; and the ability to shift charging to off-peak times to maximize customer benefits. We recommend APS and TEP develop similar studies, evaluating the following levels of EV penetration in their service territories:

- Moderate adoption level: 4% of all passenger vehicles (including fleet vehicles) in 2025 are battery electric (BEV) or plug in hybrid electric vehicles (PHEVs)[25]
- High adoption level: 8% of passenger vehicles are BEVs or PHEVs in 2025. This level of adoption is consistent with achieving a target of 1 million EVs in Arizona in 2030.[26]

Specifically, those studies should quantify

- Total electric demand;
- The number, type, and cost of charging stations under a scenario where most charging takes place at home, overnight;

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[23] Memorandum of Understanding Between Arizona, Colorado, Idaho, Montana, Nevada, New Mexico, Utah and Wyoming Regional Electric Vehicle Plan for the West, October 12, 2017. https://azgovernor.gov/sites/default/files/rev_west_plan_mou_10_3_17_final.pdf

[24] See, for example:

- Phoenix Business Journal, January 18, 2018. "SRP studying how electric vehicles impact the power grid," https://www.bizjournals.com/phoenix/news/2018/01/18/srp-studying-how-electric-vehiclesimpact-the.html
- Southern California Edison, 2017. The Clean Power and Electrification Pathway, https://www.edison.com/content/dam/eix/documents/our-perspective/g17-pathway-to-2030-white-paper.pdf.
- U.S. Department of Energy, 2017. National Plug-In Electric Vehicle Infrastructure Analysis.
- Ceres and MJB&A, 2017. Accelerating Investment in Electric Vehicle Charging Infrastructure: Estimated Needs in Selected Utility Service Territories in Seven States.

[25] This level is consistent with recent national projections by Edison Electric Institute and Bloomberg New Energy Finance, but less than the estimated amount of EVs in the vehicle fleet in states that have adopted a ZEV sales requirement as part of a vehicle fuel efficiency standard.

[26] This is also roughly consistent with the most aggressive state goals, including California's EV targets.

- The number, type, and cost of charging stations, under a scenario where higher levels of charging take place during the day in order to utilize low-cost solar PV;
- The appropriate mix of public and private charging stations; and
- The role of utilities in scenarios where they own both public and private charging stations and where they do not, and where there is mixed ownership in the marketplace.

In sum, we believe this type of focused study can help identify the potential customer benefits of electric vehicles and inform the appropriate level of utility investment in EV charging infrastructure. The plans should inform utilities' strategic investments in EV charging infrastructure and promoting EV sales.

Concluding Observations

In this filing, we have presented candidate Alternative Portfolios for both APS and TEP. These portfolios shift the emphasis of new resource investments from natural gas to renewable energy, energy storage, energy efficiency, and demand management.

Our preliminary analysis has shown that these Alternative Portfolios are capable of meeting both utilities' energy and peak demand needs well into the future. Furthermore, we are reasonably confident that they will be able to manage other operating needs such as flexible ramping, overgeneration, and voltage control. Finally, the portfolios appear to outperform the utilities' selected portfolios on a variety of metrics including cost (revenue requirements), emissions, and water use. As such, we recommend that the Commission take steps to ensure that the resource procurement decisions taken by APS and TEP in their near-term action plans are consistent with the Alternative Portfolios presented here.

Appendix A: Loads and Resources

APS Alternative Portfolio

Year	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
MW (peak)																
Load Requirements																
Peak Demand (prior to EE/DG)	7,023	7,307	7,581	7,855	8,130	8,405	8,681	8,961	9,248	9,539	9,835	10,141	10,446	10,761	11,081	11,410
Peak Demand (after EE/DG)	6,892	7,004	7,112	7,220	7,330	7,437	7,545	7,657	7,776	7,899	8,029	8,169	8,308	8,457	8,614	8,776
Reserve Requirements	961	981	1,000	1,024	1,114	1,134	1,155	1,175	1,194	1,216	1,238	1,263	1,286	1,310	1,336	1,364
Total Load Requirements	**7,984**	**8,288**	**8,581**	**8,879**	**9,244**	**9,539**	**9,836**	**10,136**	**10,442**	**10,755**	**11,073**	**11,404**	**11,732**	**12,071**	**12,417**	**12,774**
Exisitng Resources																
Nuclear	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146
Coal	1,672	1,672	1,672	1,357	1,357	1,357	1,357	970	970	970	970	970	970	970	0	0
Natural Gas	4,341	4,341	4,167	4,135	4,135	4,135	4,135	4,135	4,135	4,135	4,135	4,135	4,135	4,135	4,135	4,135
Combined Cycle	1,852	1,852	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898	1,898
Combustion/Steam Turbines	1,254	1,254	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034	1,034
PacifiCorp Seasonal Exchange	480	480	480	480	480	480	480	480	480	480	480	480	480	480	480	480
Tolling Agreements	560	560	560	565	565	565	565	565	565	565	565	565	565	565	565	565
Market/Call																
Options/Hedges/AG-X	195	195	195	158	158	158	158	158	158	158	158	158	158	158	158	158
Renewable Energy	514	514	515	515	516	516	504	504	505	505	487	488	488	476	476	476
Distributed Energy	13	13	13	13	13	14	14	14	14	14	14	14	14	14	14	14
Solar	417	418	418	418	419	419	420	420	420	420	421	421	421	421	421	421
Wind	55	55	55	55	55	55	55	55	55	55	37	37	37	37	37	37
Geothermal	10	10	10	10	10	10	10	10	10	10	10	10	10	0	0	0
Biomass/Biogas	19	19	19	19	19	19	6	6	6	6	6	6	6	3	3	3
Energy Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Microgrid	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22
Total Existing Resources	7,695	7,695	7,522	7,175	7,176	7,176	7,164	6,777	6,778	6,778	6,760	6,761	6,761	6,749	5,779	5,779
Customer Resources																
Energy Efficiency	98	223	348	473	598	723	848	973	1098	1223	1348	1473	1598	1723	1848	1973
Future Distributed Energy	15	32	43	54	64	77	90	103	116	129	140	151	162	173	183	195
Demand Response & Demand Management	18	48	78	108	138	168	198	228	258	288	318	348	378	408	436	466
Customer Resources (DSM, DG & DR)	131	303	469	635	800	968	1136	1304	1472	1640	1806	1972	2138	2304	2467	2634
Future Resources																
Nuclear (SMR)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Future Natural Gas	150	140	510	662	720	660	510	941	941	941	941	941	941	941	1641	1641
NG Combined Cycle	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NG Combustion Turbines	0	0	510	510	510	510	510	941	941	941	941	941	941	941	1641	1641
Short-Term Market Purchases	150	140	0	152	210	150	0	0	0	0	0	0	0	0	0	0
Future Renewable Energy	0	106	118	331	420	504	582	646	688	748	800	852	894	930	962	961
Wind	0	15	30	45	60	75	90	105	120	135	150	165	180	195	210	221
Solar	0	91	88	256	330	399	462	511	538	583	620	657	684	705	722	710
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Biomass/Biogas	0	0	0	30	30	30	30	30	30	30	30	30	30	30	30	30
Energy Storage	0	36	36	76	136	216	376	536	696	748	828	920	1015	1159	1483	1683
Microgrid	11	11	11	11	11	36	86	86	86	86	86	86	86	86	86	86
Total Future Resources	**161**	**293**	**675**	**1080**	**1287**	**1416**	**1554**	**2209**	**2411**	**2523**	**2655**	**2799**	**2936**	**3116**	**4172**	**4372**
Total Resources	**7,987**	**8,291**	**8,666**	**8,890**	**9,263**	**9,560**	**9,854**	**10,290**	**10,661**	**10,941**	**11,221**	**11,532**	**11,835**	**12,169**	**12,418**	**12,784**

TEP - Alternative Portfolio																
Year	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
MW **(peak)**																
Load Requirements																
Peak Demand (prior to EE/DG)	2,661	2,632	2,671	2,728	2,789	2,918	2,918	2,943	2,903	2,922	2,944	2,953	2,973	3,001	3,028	3,056
Peak Demand (after EE/DG)	2,443	2,360	2,346	2,352	2,362	2,441	2,392	2,368	2,280	2,253	2,229	2,191	2,166	2,148	2,129	2,111
Reserve Requirements	366	354	352	353	354	366	359	355	342	338	334	329	325	322	319	317
Total Load Requirements	**3,027**	**2,986**	**3,023**	**3,081**	**3,143**	**3,284**	**3,277**	**3,298**	**3,245**	**3,260**	**3,278**	**3,282**	**3,298**	**3,323**	**3,347**	**3,373**
Exisitng Resources																
Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Coal	1,411	1,241	1,241	1,073	1,073	903	903	903	903	903	903	903	903	903	793	793
Four Corners	110	110	110	110	110	110	110	110	110	110	110	110	110	110		
Navajo	168	168	168													
San Juan	340	170	170	170	170											
Springerville	793	793	793	793	793	793	793	793	793	793	793	793	793	793	793	793
Natural Gas	1237	1237	1237	1156	1156	1075	1075	1075	1075	1075	1075	1075	952	952	848	848
Sundt	422	422	422	341	341	260	260	260	260	260	260	260	260	260	156	156
Luna	184	184	184	184	184	184	184	184	184	184	184	184	184	184	184	184
Gila River	412	412	412	412	412	412	412	412	412	412	412	412	412	412	412	412
Existing CTs	219	219	219	219	219	219	219	219	219	219	219	219	96	96	96	96
Renewable Energy	134	134	134	134	134	134	134	134	134	134	134	134	134	134	134	134
Energy Storage	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Microgrid																
Total Existing Resources (excl. DR & market purchases)	2,787	2,617	2,617	2,368	2,368	2,117	2,117	2,117	2,117	2,117	2,117	2,117	1,994	1,994	1,780	1,780
Customer Resources																
Energy Efficiency	142	187	232	277	322	367	412	457	502	547	592	637	682	727	772	817
Future Distributed Energy	76	85	93	99	105	110	114	118	121	122	123	125	125	126	127	128
Demand Response (Future & Existing)	28	34	40	46	52	58	64	70	76	82	88	94	100	106	112	118
Total Customer Resources (DSM, DG & DR)	246	306	365	422	479	535	590	645	699	751	803	856	907	959	1011	1063
Future Resources																
Nuclear (SMR)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Future Natural Gas	0	1	0	80	0	200	100	100	100	100	100	100	100	100	100	100
NG Combined Cycle	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NG RICE	0	0	0	0	0	100	100	100	100	100	100	100	100	100	100	100
Short-Term Market Purchases	0	1	0	80	0	100	0	0	0	0	0	0	0	0	0	0
Future Renewable Energy	0	38	80	108	158	200	250	313	304	295	286	300	313	344	355	343
Wind	0	12	23	23	46	46	58	75	75	75	75	75	98	98	121	121
Solar	0	26	57	85	112	154	193	239	230	221	212	225	215	246	234	222
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Energy Storage	0	25	25	115	160	250	250	250	250	250	250	300	300	380	380	430
Microgrid	0	0	0	0	0	.	0	0	0	0	0	0	0	0	0	0
Total Future Resources	-	64	105	303	318	650	600	663	654	645	636	700	713	824	835	873
Total Resources	**3,033**	**2,987**	**3,087**	**3,093**	**3,165**	**3,302**	**3,307**	**3,425**	**3,470**	**3,513**	**3,556**	**3,673**	**3,614**	**3,777**	**3,626**	**3,716**

Appendix B: Energy Mix

APS Alternative Portfolio **Year**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Load Forecast (GWh)																
Sales Prior to EE/DG	29,135	30,230	31,359	32,427	33,480	34,528	35,577	36,634	37,713	38,802	39,907	41,041	42,173	43,339	44,526	45,739
Demand Side Management (cumulative)	-464	-985	-1,512	-2,038	-2,495	-2,951	-3,408	-3,869	-4,321	-4,778	-5,235	-5,700	-6,148	-6,604	-7,061	-7,531
Distributed Generation	-320	-631	-942	-1,255	-1,564	-1,950	-2,370	-2,806	-3,242	-3,672	-4,096	-4,502	-4,878	-5,225	-5,564	-5,904
Losses	1,985	2,003	2,023	2,039	2,059	2,074	2,086	2,097	2,110	2,125	2,140	2,159	2,180	2,206	2,233	2,261
Total Own Load Energy Needs	30,336	30,618	30,927	31,174	31,481	31,700	31,886	32,057	32,260	32,477	32,717	32,998	33,328	33,716	34,134	34,565
Supply-side Resources (GWh)																
Nuclear	9,296	9,176	9,176	9,202	9,296	9,303	9,299	9,326	9,296	9,299	9,299	9,326	9,299	9,293	9,303	9,326
Coal	8,053	7,183	6,321	5,609	6,085	5,586	5,458	3,399	3,305	3,211	3,117	3,023	2,929	3,399	0	0
Natural Gas (incl. tolling agreements)	9,097	9,620	10,506	10,127	9,221	9,211	8,081	9,405	9,868	9,577	9,239	8,706	8,472	7,647	10,838	10,608
Renewables (excl. DG)	2,666	3,400	3,696	4,985	5,652	6,284	6,800	7,335	7,794	8,260	8,678	9,093	9,523	9,899	10,504	10,850
Purchases	1,224	1,249	1,239	1,270	1,263	1,373	2,346	2,732	2,180	2,325	2,601	3,091	3,371	3,783	3,879	4,223
Energy Storage (round trip losses)	0	-9	-9	-20	-36	-57	-99	-141	-183	-196	-217	-241	-266	-304	-389	-442
Total Supply	30,336	30,618	30,927	31,174	31,481	31,700	31,886	32,057	32,260	32,477	32,717	32,998	33,328	33,716	34,134	34,565
Resource Mix																
Nuclear	31%	30%	30%	30%	30%	29%	29%	29%	29%	29%	28%	28%	28%	28%	27%	27%
Coal	27%	23%	20%	18%	19%	18%	17%	11%	10%	10%	10%	9%	9%	10%	0%	0%
Natural Gas	30%	31%	34%	32%	29%	29%	25%	29%	31%	29%	28%	26%	25%	23%	32%	31%
Renewables (excl. DG)	9%	11%	12%	16%	18%	20%	21%	23%	24%	25%	27%	28%	29%	29%	31%	31%
Purchases	4%	4%	4%	4%	4%	4%	7%	9%	7%	7%	8%	9%	10%	11%	11%	12%
Energy Storage	0%	0%	0%	0%	0%	0%	0%	0%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%
Total	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
RE (incl. DG), % of total load	10%	13%	15%	19%	22%	24%	27%	29%	31%	33%	35%	36%	38%	39%	40%	41%

TEP Alternative Portfolio

Year	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Load Forecast (GWh)																
Retail Sales Prior to EE/DG	8,734	8,818	8,885	9,000	9,245	9,713	9,986	10,106	10,199	10,298	10,387	10,487	10,584	10,691	10,798	10,907
Demand Side Management (cumulative)	-829	-994	-1,159	-1,324	-1,489	-1,654	-1,819	-1,984	-2,149	-2,314	-2,479	-2,644	-2,809	-2,974	-3,139	-3,304
Distributed Generation	-342	-385	-420	-451	-478	-501	-521	-538	-553	-555	-563	-569	-571	-575	-578	-582
Firm Wholesale Sales	589	611	608	658	713	755	655	686	401	401	401	402	401	401	401	402
Losses	571	563	554	552	559	582	581	579	553	548	542	537	532	528	524	520
Short-term Wholesale Sales (incl. losses)	4,330	2,794	3,015	1,037	1,576	984	1,034	1,330	1,762	1,584	1,578	1,653	1,887	2,169	2,212	2,199
Total Energy Needs	13,052	11,407	11,483	9,471	10,126	9,878	9,916	10,178	10,212	9,962	9,865	9,866	10,024	10,239	10,217	10,142
Supply-side Resources (GWh)																
Coal	9,132	7,942	7,044	5,300	5,108	4,650	3,955	3,955	3,955	3,955	3,955	3,955	3,955	3,955	3,821	3,473
Natural Gas	3,065	2,310	2,952	2,570	2,904	2,945	3,306	3,073	3,134	2,959	2,938	2,913	2,781	2,832	2,587	2,878
Renewables (excl. DG)	856	1,161	1,492	1,626	2,147	2,336	2,708	3,202	3,175	3,100	3,025	3,061	3,350	3,532	3,889	3,881
Energy Storage (round trip losses)	0	-5	-5	-24	-34	-53	-53	-53	-53	-53	-53	-63	-63	-80	-80	-90
Total Supply	13,052	11,407	11,483	9,471	10,126	9,878	9,916	10,178	10,212	9,962	9,865	9,866	10,024	10,239	10,217	10,142
Resource Mix																
Coal	70%	70%	61%	56%	50%	47%	40%	39%	39%	40%	40%	40%	39%	39%	37%	34%
Natural Gas	23%	20%	26%	27%	29%	30%	33%	30%	31%	30%	30%	30%	28%	28%	25%	28%
Renewables (excl. DG)	7%	10%	13%	17%	21%	24%	27%	31%	31%	31%	31%	31%	33%	34%	38%	38%
Energy Storage	0%	0%	0%	0%	0%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%	-1%
Total	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
RE (incl. DG), % of total load	9%	13%	16%	21%	25%	27%	31%	35%	35%	35%	34%	35%	37%	38%	41%	42%

Appendix C: Comparison of Resource Additions for APS and TEP Selected Portfolio vs. Alternative Portfolios

APS Comparison

Resource Additions **(Nameplate Capacity, MW)**	**Alternate Portfolio (2017 – 2022)**	**Alternate Portfolio (2017 – 2032)**	**APS' Selected Portfolio (2017 – 2022)**	**APS' Selected Portfolio (2017 – 2032)**
Natural Gas Combined Cycle	+0	+0	+1,500	+2,000
Natural Gas Combustion Turbine	+510	+1,600	+941	+3,516
Energy Efficiency (contribution to peak demand)	+723	+1,973	+491	+900
Demand Response	+168	+466	+51	+173
Utility-scale Wind	+375	+1,105	+0	+90 (contract extension)
Utility-scale Solar PV	+700	+1,920	+0	+0
Battery Storage	+270	+1,834	+3	+397
Distributed PV	+1,200	+3,200	+1,200	+3,200

TEP Comparison

Resource Additions **(Nameplate Capacity, MW)**	**Alternate Portfolio (2017 – 2022)**	**Alternate Portfolio (2017 – 2032)**	**TEP's Reference Case (2017 – 2022)**	**TEP's Reference Case (2017 – 2032)**
Natural Gas Combined Cycle	0	0	412	412
Natural Gas Reciprocating Internal Combustion Engine (RICE)	100	100	192	336
Energy Efficiency (contribution to peak demand)	225	817	83	176
Demand Response	30	90	18	39
Utility-scale Wind	200	525	100	325
Utility-scale Solar PV	240	600	80	450
Battery Storage	250	430	50	100
Distributed PV	88	133	88	133