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BEFORE THE ARIZONA CORPORATION COMMISSION

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Chairman
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Arizona Corporation Commission
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RESOURCE PLANNING AND PROCUREMENT IN 2015 AND 2016	DOCKET NO. E-00000V-15-0094 DECISION NO. 76632 ORDER

Open Meeting
March 13, 2018
Phoenix, Arizona

BY THE COMMISSION:

FINDINGS OF FACT

1. The Utilities Division Staff ("Staff") has completed the Assessment of the 2015-2016 Integrated Resource Plans of the Arizona Electric Utilities ("Assessment") as required by Arizona Administrative Code ("A.A.C.") R14-2-704(A), and Decision Nos. 75068 and 75269. After a cost benefit evaluation, Staff determined substantial funds could be saved by performing the assessment in-house. Accordingly, Staff did not retained a consultant for this Assessment.

Background

2. The Assessment represents the opinion of Staff. The Assessment is not an evaluation of individual electric service providers' facilities or quality of service. The Assessment does not set Commission policy or approve of any plan or specific project(s). Rather, it assesses the adequacy of the Integrated Resource Plans ("IRP" or "IRPs") to meet the requirements of the Commission's

Resource Planning and Procurement Rules ("Rules")[1]. The IRPs have been prepared by the four Load-Serving Entities ("LSE" or "LSEs") as defined in the Rules. The LSEs are Arizona Electric Power Cooperative ("AEPCO"), Arizona Public Service Company ("APS"), Tucson Electric Power Company ("TEP"), and UNS Electric, Inc. ("UNSE"). In addition, the second largest electric utility in Arizona, Salt River Project ("SRP"), which is not subject to these rules and regulations of the Commission and is not required to file an IRP, has voluntarily supplied its most recent Western Area Power Administration ("WAPA") IRP filing for the five year period 2013-2017. However, due to the planning period, the information is not included in this Assessment.

3. An IRP is essentially the utility's plan to meet the future electric service needs of its customers in a way that considers environmental impacts along with the concerns of customers, regulators, stockholders and 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 end result 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 served by the LSEs in Arizona.

4. 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, while considering the following factors[2]:

A. The total cost of electric energy services;
B. The degree to which the factors that affect demand, including demand management, have been taken into account;
C. The degree to which supply alternatives, such as self-generation, have been taken into account;
D. Uncertainty in demand and supply analyses, forecasts, and plans, and whether plans are sufficiently flexible to enable the utility to respond to unforeseen changes in supply and demand factors;
E. The reliability of power supplies, including fuel diversity and non-cost considerations;

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[1] An LSE is defined 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."
[2] The Commission's Resource Planning and Procurement Rules, A.A.C. R14-2-701 et seq. (Page 114. http://apps.azsos.gov/public_services/Title_14/14-02.pdf)

F. The reliability of the transmission grid;

G. The environmental impacts of resource choices and alternatives;

H. The degree to which the LSE considered all relevant resources, risks, and uncertainties;

I. The degree to which the LSE's plan for future resources is in the best interest of its customers;

J. The best combination of expected costs and associated risks for the LSE and its customers; and,

K. The degree to which the LSE's resource plan allows for coordinated efforts with other LSEs.

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

6. The Commission's decision in the initial IRP docket (2012 IRP filings, Decision No. 73884) acknowledged the special circumstances concerning AEPCO, namely that AEPCO does not serve any retail load, and its wholesale, supply-only role has declined dramatically since 2001. Therefore, the Commission ordered AEPCO to file whatever information, data, criteria and studies it has used in its 15-year planning studies, and that future AEPCO IRPs need not be acknowledged by the Commission. Decision No. 73884 also requires that each load-serving entity with possible extra capacity resulting in a reserve margin beyond 20 percent over a period of two years must include an alternative scenario in its IRP, in which any incremental additions of capacity, mandated or not, that contribute to the possible extra capacity, are delayed until such additions no longer contribute to the additional capacity[3]. The costs of this alternative scenario, including projected revenue requirements, must be included in the IRP.

7. In Decision No. 75068, (May 8, 2015), the Commission acknowledged the 2014 IRPs submitted by APS, TEP, and UNSE. The Commission also found that the 2014 IRP of AEPCO satisfied the requirements established in Decision No. 73884. Decision 75068 required APS and TEP to reexamine their load forecasting techniques prior to filing their 2016 IRPs to ensure that the resource plans would not forecast high load growth which would be unlikely to occur. The companies were required to file reports on the results of their reexamination by October 31, 2015. Decision No.

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[3] A reserve margin beyond 20 percent over a period of two years was not seen in any of the 2015 and 2016 IRPs.

75068 also required that the Load Serving Entities include a discussion of the status of their Energy Imbalance Market ("EIM") market participation deliberations in the update to their respective IRP and 3-Year Action Plans. APS, TEP, and UNS Electric were required to hold public pre-filing workshops prior to detailed portfolio planning and analysis in future IRPs. APS, TEP, UNSE, and AEPCO were also required to include a discussion of the development status and associated costs and benefits of new technologies they considered in their IRP and associated 3-Year Action Plans. In addition, APS, TEP, UNSE, and AEPCO were required to consider the following portfolios in their IRPs in addition to the portfolios they typically incorporate: (1) energy storage; (2) small nuclear reactors; (3) expanded renewables (including distributed resources): biogas, solar, wind, geothermal, etc.; and (4) expanded energy efficiency/demand response/integrated demand side management (which include the effect of microgrids and combined heat and power). Each LSE was also required to provide a discussion regarding its plans for aging generation plants in its IRP. Lastly, all LSEs (except AEPCO) were required to include a narrative description of any substantial changes to 3-Year Action Plans.

8. In a letter filed in this docket, dated June 16, 2015, Commissioner Little proposed extending the filing date for the next IRPs from April 1, 2016 to April 1, 2017 due to uncertainty surrounding the Environmental Protection Agency's Clean Power Plan ("CPP"). Commissioner Little requested comments from the utilities regarding the proposed filing extension. On June 19, 2015 Commissioner Burns filed a letter in the docket agreeing with Commissioner Little and further proposed to extend the IRP cycle from 2-years to 3-years, stating that the increased time would allow more thorough and comprehensive resource plans to be developed. Commissioner Burns also requested comments regarding the change to a 3-year cycle. Several stakeholders filed comments in the docket regarding extending the filing deadlines. In general, the majority of stakeholders supported extending the filing deadlines. On July 9, 2015, Commissioner Burns wrote a letter that discussed a two-part filing, consisting of a preliminary filing in April 2016 followed by a final filing in June 2017. In addition, Commissioner Burns provided a proposed timeline. In general, there was broad stakeholder support for a two-part filing. As a result, Decision No. 75269 (September 16, 2015) established an alternative timeline for the processing of the IRPs. Consequently, APS, TEP, and

UNSE were required to file Preliminary IRPs by March 1, 2016, and to provide updates to their IRPs by October 1, 2016. AEPCO was required to file its preliminary IRP by September 1, 2016. In addition, Decision No. 75269 also required an April 3, 2017 filing date for the final 2017 IRPs.

9. On March 8, 2017 APS requested an extension of time until April 10, 2017 to file its final IRP. On April 10, 217 the Hearing Division issued an order approving the request, in Decision No. 76859. On March 30, 2016 AEPCO requested an extension until May 3, 2017 to file its final IRP. On April 11, 2017 the Hearing Division issued an order approving the request, in Decision No. 76060. On September 19, 2017, Staff requested an extension of time to file the Staff Report and proposed order from October 1, 2017 to November 1, 2017. On October 5, 2017 the Hearing Division issued a recommended order granting Staff's request.

Compliance Requirements from Decision No. 75068

10. As described above, the Commission ordered additional compliance items in Decision No. 75068 (May 8, 2015).

I. Load Forecasting

11. "...Arizona Public Service Company and Tucson Electric Power Company shall include a report on the results of the re-examination of their load forecasting techniques..."[4]

APS:

12. As required in Decision No. 75068, APS re-examined its load forecasting in order to avoid forecasting high load growth that is unlikely to occur. APS has stated that previous forecasts have been too high due to an expectation of stronger economic and population growth following the 2008 recession than had actually occurred. For the evaluation APS focused on the components which have the largest impact on load growth, which are: the population growth forecast, residential use per customer forecast, and the commercial and industrial electricity demand forecast.

13. Based on the results from the re-evaluation, APS decided to develop a new econometric model designed to provide clearer insights into changes in population migration patterns. APS has stated that population growth is the most important variable to be considered in developing a

[4] Decision No. 75068. Page 14; http://docket.images.azcc.gov/0000162009.pdf

load forecast and most of the other economic growth variables used in developing different load forecast elements are directly influenced by the population growth forecast. APS also stated that the most variable component of the population growth projection is the net migration because it is sensitive to near-term business cycle effects. As a result, in order to enhance the net migration forecast, APS has engaged the Economic and Business Research Center at the University of Arizona to construct more formal statistical models of migration. According to APS' 2017 IRP, the new models were implemented.

14. In regard to the residential use per customer forecast component, APS tested six different models and concluded the current "residential end-use model remains the preferred modeling tool for developing projections... primarily because the current method has not suffered from any serious deficiencies and none of the other alternatives appear to be better." For the commercial and industrial electricity demand forecast, APS tested five different models and found that the model in use for the last several years continues to be the preferred method.

15. APS has stated that as part of good business practice, it periodically re-examines its load forecasting techniques and it will continue testing alternate approaches to forecasting going forward.

TEP:

16. As required by Decision No. 75068, TEP submitted a report that detailed the methodology that goes into developing a load forecast. The report detailed each of the forecasts that are necessary to establish a total retail sales forecast as well as a retail peak forecast. This included a discussion of the residential and commercial customer forecast methodology along with the residential and commercial use per customer forecast, the large industrial and mining sales forecast, and the retail peak forecast.

17. TEP has stated that it uses a "bottom up" approach for the energy forecast. A separate monthly energy forecast is prepared for each of the major rate classes. TEP stated that the factors impacting usage in each of the rate classes vary significantly, thus the methodology used to produce the individual rate class forecasts also varies. Large industrial and mining customers are tracked and the sales are forecasted on an individual basis. The residential, commercial, and small

industrial class sales are forecasted on a class basis by combining a customer forecast for each class with a monthly use per customer forecast for each class. The retail peak forecast is based on the historical relationship between hourly demand load, weather, calendar effects, and sales growth.

II. Discussion of EIM Participation

18. "...Load Serving Entities shall include a discussion of the status of their EIM market participation deliberations in the update to their respective IRP and 3-Year Action Plans."[5]

APS:

19. APS included a discussion of its EIM participation in its March 1, 2016 Preliminary IRP filing. APS stated it would be joining the EIM and that it anticipated annual cost savings to APS customers of approximately $7 million, while also citing optimized generation dispatch as a benefit in providing a platform for integrating growing renewable energy resources. In the 3-Year Action Plan, APS indicated participation in the California Independent System Operator ("CAISO") EIM would begin in October 2016.

20. A discussion regarding APS' EIM participation was also included in its 2017 IRP filing. APS joined the CAISO EIM as a new participating Balancing Authority on October 1, 2016. Since APS joined the EIM, the CAISO has published the Fourth Quarter 2016 Western EIM Benefits Report and APS's gross benefits from EIM participation were approximately $6 million. APS was a net exporter in both the 15-minute and 5-minute tranches in all three months of the quarter. APS' largest export volumes went to CAISO while its largest import volumes came from PacifiCorp.

TEP:

21. TEP provided a discussion of its EIM participation on Page 23 of its 2017 IRP. TEP contracted with the energy consulting firm E3 to perform a study to evaluate projected economic benefits of TEP's participation in the EIM. Based on the results of the E3 study, TEP estimates an annual benefit of approximately $2.5 million. However, it expects that the benefit will diminish over time. TEP has started the process of determining the relevant costs associated with joining the

[5] Decision No. 75068. Page 15; http://docket.images.azcc.gov/0000162009.pdf

CAISO EIM as well as evaluating what other western EIM market options may be available. TEP estimates that the cost analysis will be completed sometime during the summer of 2017[6]

22. In addition, TEP has engaged and plans on continuing engagement with market operators (such as the CAISO, the Southwest Power Pool, and the Mountain West Transmission Group) to determine the best path forward for its customers.

23. Although TEP did not include a discussion of its EIM participation in the context of its Five-Year Action Plan, it discussed its participation thoroughly elsewhere in the IRP.

<u>UNSE</u>:

24. UNSE discussed EIM participation in its Preliminary IRP filing as well as in its 2017 IRP. UNSE is within the TEP balancing authority and will make a determination to participate in the EIM based on TEP's analysis and results.

<u>AEPCO</u>:

25. AEPCO stated that it is exploring whether participation in the California EIM or another structured market may be beneficial to cooperative electric consumers in its 3-Year Action Plan[7].

III. Pre-filing Workshops and Stakeholder Outreach

26. APS held a Stakeholder Forum on February 9, 2016, during which APS outlined its approach to compliance with the IRP Rules and solicited input from stakeholders. APS held a second Stakeholder Forum on November 18, 2016, and presented its Preliminary IRP to stakeholders.

27. TEP and UNSE held a combined IRP Workshop for stakeholders on November 2, 2016. The Preliminary IRPs for TEP and UNSE were presented and stakeholder input was solicited.

28. Staff held a public IRP Workshop on July 18, 2016. APS, TEP & UNSE each presented their preliminary IRPs, and Vote Solar gave a presentation on the benefits of rooftop solar Distributed Generation.

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[6] Page 195 of TEP's 2017 IRP. http://docket.images.azcc.gov/0000178618.pdf

[7] Page 118. http://docket.images.azcc.gov/0000179477.pdf Page 118.

IV. Discussion of Development Status and Associated Costs and Benefits of New Technologies

29. Decision No. 75068 required that the LSEs "include a discussion of the development status and associated costs and benefits of new technologies they are considering in their 2016 Integrated Resource Plans submitted for Commission consideration and associated 3-Year Action Plans, and any updates thereto."[8]

APS:

30. APS included a discussion of various new technologies in Chapter 2 (Future Resource Options) of its 2017 IRP as well as Chapter 4 (Modernizing the Grid). Chapter 2 provided an overview of each resource, a description of each technology's operational characteristics, the development status of said technology, and the associated benefits. When comparing and analyzing the benefits of various resource technologies, APS also considered water usage in assessing the viability of new technologies, citing the deployment of low water use technologies as an integral part of the planning process. According to APS' 2017 IRP, the lowest water using technologies are solar photovoltaic ("PV"), Demand Side Management ("DSM"), combustion turbines, dry-cooled aeroderivative combustion turbines, and dry-cooled combined cycle. The most water intensive technologies are wet-cooled aeroderivative turbines, wet-cooled combined cycle, and nuclear.

31. Chapter 4 offered a discussion of distributed energy as a resource and APS' efforts to better assess distributed energy impacts and facilitate it as a component of grid and resource planning. APS provided information regarding numerous advanced technologies and programs being used to continue advances in: two-way communication technologies, grid health monitoring systems, and hosting capacity information to increase power quality and system responsiveness.

32. Based on results from APS' All-Source RFP; market combined cycle, combustion turbines, and demand response are listed as the three cheapest technologies in terms of capital costs ($ Per kW/Year). APS has stated there is a need to make resource comparisons on a per unit of reliability measure basis ($/kW) rather than a unit of energy measure ($/kWh) or levelized energy

[8] Decision No. 75068. Page 15; http://docket.images.azcc.gov/0000162009.pdf

comparison basis, because there is a difference in value associated with each resource related to resource dispatchability.

TEP:

33. TEP provided an extensive discussion regarding the development status, associated costs, and benefits of new technologies in Chapters 4, 5, 6, and 7 of its 2017 IRP.

34. In Chapter 4 of its 2017 IRP, TEP included a resources matrix where each technology is described by category, type, carbon profile, state of technology, primary use, and whether it can be dispatched upon demand. The resources are separated by category: such as Load Modifying Resources, Load Serving Renewable Resources, Load Serving Conventional Resources, and Grid Balancing Resources. Furthermore, the resources listed are: energy efficiency, distributed generation, rate design, wind, solar, natural gas combined cycle, pulverized coal, small modular nuclear, reciprocating engines, combustion turbines, pumped hydro storage, demand response, and battery storage. Also included in Chapter 4 was the levelized cost of energy for each resource[9].

35. According to Lazard's results, the cheapest resources to most expensive are: energy efficiency ("EE"), solar PV – tracking, solar PV – fixed tilt, wind, natural gas combined cycle, solar PV – commercial and industrial, small modular nuclear, solar PV – residential, reciprocating engines, combustion turbine, battery storage, and demand response.

36. Chapters 5, 6, and 7 included discussions related to each technology's characteristics, benefits, risks, and construction lead time. Specifically, Chapter 5 discussed distributed generation resources, Chapter 6 discussed load serving resources, and Chapter 7 discussed grid balancing and load leveling resources.

UNSE:

37. In Chapter 6 of UNSE's 2017 IRP, technology costs and development status are discussed in the context of future resource requirements. Specifically, the technologies included grid

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[9] TEP specifically references Lazard's "Levelized Cost of Energy Analysis 10.0 (December 2016)" and Lazard and Enovation Partners' "Levelized Cost of Storage Analysis 2.0 (December 2016)."
https://www.lazard.com/media/438038/levelized-cost-of-energy-v100.pdf,
https://www.lazard.com/media/438042/lazard-levelized-cost-of-storage-v20.pdf

balancing resources such as energy storage and fast response thermal generation units such as reciprocating internal combustion engines.

AEPCO:

38. In Tab C of the confidential version of AEPCO's 2017 IRP, AEPCO provides detailed cost and planning assumptions for prospective resources. In addition, Tab G also discussed the costs and benefits of energy storage.

V. Portfolios

39. Decision No. 75068 required that the LSEs "consider the following portfolios in their 2016 Integrated Resource Plans in addition to the portfolios they typically incorporate: (1) energy storage; (2) small nuclear reactors; (3) expanded renewables (including distributed resources): biogas, solar, wind, geothermal, etc.; and (4) expanded energy efficiency/demand response/integrate demand side management (which shall include the effect of microgrids and combined heat and power). If the Load Serving Entities did not include these portfolios in their Integrated Resource Plans, they shall indicate the reason(s) why they were excluded."[10]

APS:

40. APS considered each of the required portfolios and specifically refer to each as; Expanded Demand Side Management, Expanded Renewables, Energy Storage Systems, and Nuclear Small Modular Reactor.

TEP:

41. TEP provided a thorough discussion regarding alternative portfolios in Chapter 13 of its 2017 IRP. The list of portfolios analyzed included: an energy storage case plan, small nuclear reactors case plan (combined with full coal retirement), expanded energy efficiency case plan, and high solar case plan (substituted for the expanded renewables case plan).

42. The full coal retirement case plan was combined with the small nuclear reactor case plan based on the view that coal and nuclear resources provide the same service and as a means of maintaining some resource diversity in the absence of coal-fired generation. The expanded renewables

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[10] Decision No. 75068. Pages 15 & 16; http://docket.images.azcc.gov/0000162009.pdf

case plan was replaced with a high solar case plan because the reference case plan portfolio already had high renewable energy assumptions. Specifically, the high solar case plan allowed TEP to analyze the effects of a lower diversity renewable energy mix.

UNSE:

43. In Chapter 9 of UNSE's 2017 IRP, three alternative portfolios were analyzed: the Expanded Energy Efficiency Case Plan, the Expanded Renewable Energy Case Plan, and the Combustion Turbine Case Plan. The alternative portfolios vary from the list presented in UNSE's Preliminary IRP.

44. The Combustion Turbine Case Plan represented an alternative to the 2022 Natural Gas Combined Cycle addition in the Reference Case Plan. A specific Energy Storage Case plan was not presented because energy storage had been incorporated into the Reference Case Plan. In addition, the Small Modular Nuclear Reactor Case plan was not analyzed due to the high capital costs for SMR resources relative to UNSE's existing rate base. A Market-Based Reference Case Plan was not analyzed because under the Reference Case Plan, UNSE had capacity in excess of the 15 percent reserve margin in all years beyond the five years where market purchases can be included in the portfolio.

AEPCO:

45. AEPCO's resource portfolio evaluations are based on the forecasted resource needs of all its Class A Full Requirements Members as well as including its Partial Requirements Members. Because AEPCO is unique due to the fact that it supplies power only at wholesale to its Class A Members and it has no demand side component, the portfolios analyzed were based on the specific needs of its members and focused on the most realistic and cost-effective options available given AEPCO's unique position. Six scenarios were modeled by AEPCO in its IRP, each considered varying effects of the Clean Power Plan (including the availability of Emission Rate Credits) and forecasted natural gas and electric market prices, and examined the suitability of certain resource options under those possible futures.

46. Energy Storage was considered in an ancillary analysis and provided as part of AEPCO's IRP submission (behind Tab G). Small Nuclear Reactors were not considered by AEPCO

due to the regulatory burden and expense of operating a nuclear facility, especially given AEPCO's small size. Expanded Renewables were considered in AEPCO's IRP modeling. Expanded Energy Efficiency/Demand Response/Demand Side Management were not considered because AEPCO operates solely on the wholesale level.

VI. Plans for Aging Generation

47. Decision No. 75068 required that each LSE "provide a thorough discussion regarding its plans for aging generation plants in its 2016 Integrated Resource Plan…"[11]

APS:

48. APS provided a discussion of its plans for aging generation plants in the Response to Rules Section D – Supply section of its IRP, as well as in Chapter 7, and in its Action Plan (Chapter 8).

49. Four Corners 1, 2, and 3 were retired on December 31 2013 and APS finished dismantling the units in November 2016 and does not plan on fully decommissioning the site until after the retirement of Units 4-5, which is beyond the time frame of the Planning Period. Saguaro Steam 1 and 2 were retired June 30, 2013. Ocotillo Steam 1 and 2 are expected to be retired in 2018.[12] Cholla 2 was retired on October 1, 2015. Cholla 1 and 3 could potentially be retired in the 15-year Planning Period because Cholla is facing expensive environmental upgrade costs.[13] APS is continuing to evaluate its options related to Cholla, and has stated it will inform the Commission upon making any decisions on the matter.

50. In addition to providing updates on the status of the plants mentioned above, APS provided information related to the decommissioning costs of each plant and the associated reasons for decommissioning. Each of the seven portfolios considered by APS in the development of the 2017 IRP included planned major upgrades and plant retirements. Portfolio inputs and analysis results can be found in Chapter 7, in the Portfolios section.[14]

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[11] Decision No. 75068. Page 16; http://docket.images.azcc.gov/0000162009.pdf

[12] As a condition of Decision No. 76374, the entire Ocotillo Modernization Project will be in service before the rate effective date of APS's next general rate case. Exhibit A: http://docket.images.azcc.gov/0000182797.pdf

[13] Described in section D.17, page 179, of APS' 2017 IRP. http://docket.images.azcc.gov/0000178832.pdf

[14] Page 115 of APS' 2017 IRP. http://docket.images.azcc.gov/0000178832.pdf

TEP:

51. TEP discussed aging plants and retirements in Chapter 3 of its IRP. Over the next several years there will be significant coal and natural gas generating unit retirements. San Juan Unit 2 will cease operations by December 31, 2017. TEP has stated all 3 units at Navajo Generating Station could be retired by the end of 2019. TEP is currently weighing its options to completely exit and terminate its participation on San Juan Unit 1 by the end of June 2022. TEP is also committed to retiring and replacing its older and less efficient natural gas steam generators at Sundt Generating Station. In addition, TEP also provided a discussion within its Five-Year Action Plan regarding coal and natural gas retirements.

UNSE:

52. UNSE is not anticipating any retirements during the planning period.

AEPCO:

53. "AEPCO's wholesale power contracts with its Class A Members currently reflect discontinuation of operations of Apache Generating Station's CC1, GT2, and GT3 on December 31, 2020. However, as a result of discussions with its Members, AEPCO anticipates contract extensions on these units beyond 2020 through 2035. Other Apache Station units are expected to retire at the end of the current Class A Member contracts in 2035."[15]

VII. 3-Year Action Plans

54. In Decision No. 75068 (May 8, 2015), the Commission ordered the LSEs, with the exception of AEPCO, to file updates to the three-year Action Plans contained in their respective IRPs whenever a substantive change occurs in the near term resource plan.

APS:

55. APS's Three-Year Action Plan for years 2017 through 2021 presents a nine-point summary of its intended resource initiatives over the three year planning period. The nine points in APS's Action Plan are summarized as follows:

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[15] Page 52. http://docket.images.azcc.gov/0000179477.pdf

56. Future Resources - APS issued an All-Source RFP for 400 to 600 MW of capacity in March 2016. After a comprehensive review of and analysis of received proposals, APS selected the 565 MW Arlington Valley, LLC Gas Tolling Agreement. The agreement allows APS 565 MW of capacity from the Arlington Valley combined cycle power plant beginning in 2020 for a period of six years to meet summertime peak load conditions throughout the months from June to September. APS intends to issue another RFP in 2017 for summer season peak capacity needs for 2021 and beyond.

57. Also during the Three-Year Action Plan period, APS intends to conduct initial siting activities for a wide range of resource opportunities.

58. Ocotillo Modernization Project - Site work has commenced at the Ocotillo plant site, including grading, foundation work, and underground utilities installation, as well as removal of existing oil tanks. Delivery of components for the first two of the five combustion turbines has also begun. Additional work includes preparation for the addition of two new 230kv generation connection circuits that will be interconnected to the existing 230kv Ocotillo Substation. The Ocotillo project is planned to be in service by summer 2019[16].

59. Evaluate and Decide on Remaining Coal Fleet - APS continues to execute its plans for the Four Corners Generating Station[17], and is evaluating plans for the Cholla Power Plant. Cholla Unit 2 was retired on October 1, 2015, and APS plans to no longer burn coal in Units 1 and 3 beyond 2024.

60. Based on a February 2017 decision amongst the owners of the Navajo Generating Station, APS will maintain its allocation of capacity from the plant through December 2019, providing that an agreement can be reached with the Navajo Nation. APS notes that discussions regarding the future of the Navajo Generating Station are continuing amongst a range of parties. APS will continue to participate in these discussions and will update its Three-Year Plan as decisions are made on this and other coal generating resources.

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[16] reference footnote 12 for additional information

[17] APS plans to add Selective Catalytic Reduction equipment. See Exhibit A: http://docket.images.azcc.gov/0000182797.pdf

61. Add Transmission Resources - APS's 2017-2026 Ten-Year Transmission System Plan includes 38 miles of 500kV transmission lines, 14 miles of 230kV transmission lines and five substations. Specific projects to be completed during the Three-Year Action Plan include the Mazatzal 345/69kV substation; the Ocotillo Modernization Project interconnection facilities; the Morgan – Sun Valley 500kV line; and the North Gila – Orchard 230 kV line Circuit No. 1.

62. Continue Expansion of Renewable Resources - APS will continue its Solar Innovation Study designed to study the integration of customer-side advanced technologies. Technologies to be investigated include rooftop solar, advanced inverters, home energy management systems, load controllers, and demand-based rate structures.

63. APS also intends to invest in its proposed AZ Sun II program. The purpose of the AZ Sun II program is to expand access to rooftop solar for low and moderate income consumers in APS's service territory.

64. Continued Implementation of Customer-Side Resources - Based on APS's Modified 2017 DSM Implementation Plan, APS plans on energy savings of approximately 562,000 MWh in 2017. The 2017 portfolio of DSM programs have been reshaped to put more emphasis on load shifting and peak load reduction measures.

65. Invest in Advanced Grid Technologies - APS will continue to implement its state-of-the-art grid management system, Project Illuminate, which uses advanced technologies to improve internal visualization and diagnostic capabilities.

66. CAISO Energy Imbalance Market - APS joined the CAISO Energy Imbalance Market ("EIM") on October 1, 2016. CAISO has published the Fourth Quarter 2016 Western EIM Benefits Report which states that APS's gross benefits from EIM participation was approximately $6 million, with APS being a net exporter in both the 15-minute and 5-minute tranches in all three months of the quarter.

67. Natural Gas Storage - APS is exploring potential options to develop a natural gas storage facility to add capacity, enhance reliability, and increase flexibility.

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TEP:

68. Although the Commission's IRP Rules require the Load Serving Entities to file a Three-Year Action Plan, TEP elected to file a Five-Year Action Plan. TEP's Five-Year Action Plan for years 2017 through 2022 presents a seven-point summary of its intended resource initiatives over the five year planning period. The seven points in TEP's Action Plan are summarized as follows:

a. Over the next five years, TEP plans to add 100 MW of utility-scale wind and 100MW of utility-scale solar resources.
b. TEP plans to reduce its coal resource capacity by 508 MW over the next five years as part of its portfolio diversification strategy.
c. TEP plans to move forward with a generating resource modernization project at its Sundt Generating Station. TEP will replace older gas-fired steam units with new natural gas fueled reciprocating internal combustion engines.
d. TEP will continue to implement cost-effective Energy Efficiency and Demand Response programs.
e. TEP plans to add a 50 MW battery storage project in 2019, and another 50 MW battery storage project in 2021.
f. TEP's 2017 Reference Case IRP recommends the addition of 413 MW of natural gas combined cycle capacity in 2022. TEP plans to meet this capacity need through a combination of wholesale market purchases, PPAs and potentially low-cost plant acquisitions[18].
g. TEP will continue to investigate, along with other Arizona utilities, the feasibility of developing in-ground natural gas storage capabilities.

UNSE:

69. Although the Commission's IRP Rules require the Load Serving Entities to file a Three-Year Action Plan, UNSE elected to file a Five-Year Action Plan. UNSE's Five-Year Action Plan for years 2017 through 2022 presents a six-point summary of its intended resource initiatives over the five year planning period. The six points in UNSE's Action Plan are summarized as follows:

a. UNSE plans to continue its community scale build out of renewable energy and expects to serve 20 percent of its retail load using renewable energy by 2020. UNSE will complete a 4.4 MW solar fixed PV project in the summer of

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[18] According to an October 13, 2017 Press Release by the company, "TEP has secured use of an efficient, low-cost, natural gas power plant that will diversify the company's energy portfolio and support efforts to deliver at least 30 percent of the company's power from renewable resources by 2030. TEP has reached an agreement with SRP to purchase the output of Unit 2 at the gas-fired Gila River Power Station. TEP, which already shares ownership of Gila River Unit 3, also secured an option to purchase Unit 2 from SRP, which is acquiring Units 1 and 2 at the plant. TEP will begin using power from Gila River Unit 2 after SRP's acquisition is finalized, which is expected by early 2018. TEP's option to purchase the 550 MW unit will be available for three years after SRP takes ownership. TEP has relied on a 413 MW share of Gila River Unit 3 since buying that unit in partnership with sister company UNS Electric in 2014. Energy from Gila River will help TEP offset the potential loss of 508 MW of coal-fired resources."

2017 and in 2018 the Company is expecting its 46 MW Grayhawk solar project will commence commercial operation.

b. UNSE intends to conduct detailed Technology Assessments and/or issue a Request for Proposal for fast-responding resources to be in service by 2022.

c. UNSE will continue to implement cost-effective EE programs based on Arizona's EE standard.

d. UNSE plans to add 5 MW of battery storage capacity in 2019, and another 5 MW of battery storage capacity in 2022.

e. UNSE's 2017 Reference Case IRP recommends the addition of 137 MW of natural gas combined cycle capacity in 2022. UNSE plans to meet this capacity need through a combination of wholesale market purchases, PPAs and potentially low-cost plant acquisitions.

f. UNSE will continue to investigate, along with other Arizona utilities, the feasibility of developing in-ground natural gas storage capabilities.

Annual Renewable Energy Requirement

70. The Commission's Renewable Energy Standard and Tariff ("REST") rules require affected utilities to produce a certain percentage of renewable energy each year based on the utility's annual retail sales. This Annual Renewable Energy Requirement ("ARER") is defined in R14-2-1804 and requires affected utilities to produce seven percent of their annual retail sales from renewable energy in 2017. The ARER increases by one percent per year until it reaches 15 percent in 2025.

71. APS's IRP indicates that it plans on exceeding the ARER requirement with 14.3 percent of renewable generation in 2017; 21.3 percent in 2025; and 25.6 percent in 2032 (the end of the IRP planning horizon). APS was required to achieve 1,700 GWh of incremental renewable generation by December 31, 2015, per Decision No. 71448.

72. TEP has set a goal of 30 percent renewable energy as a percentage of sales by 2030. TEP's IRP plans to exceed the ARER requirements in 2017 and each year thereafter as part of its 30 percent by 2030 goal.

73. In 2017, UNSE plans to produce approximately 115 GWh of renewable energy, which equates to seven percent of forecast retail sales for the year. UNSE anticipates reaching an annual renewable energy production of approximately 20 percent of retail sales by 2020, and will remain above the 15 percent REST requirement through 2032.

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74. AEPCO was relieved of the IRP Rules requirements related to REST compliance by Decision No. 73884. This relief was granted to AEPCO in recognition of AEPCO's unique situation as a wholesale-only energy supplier.

Distributed Renewable Energy Requirement

75. The Commission's Renewable Energy Standard and Tariff ("REST") rules require affected utilities to produce a certain percentage of their ARER from distributed renewable resources. The Distributed Renewable Energy Requirement ("DRER") in R14-2-1805 mandates 30 percent of the utility's ARER in 2017 and throughout the IRP planning horizon.

76. APS's IRP indicates that it plans to exceed the 30 percent requirement, with distributed resources contributing 75 percent of its ARER in 2017, and 127 percent in 2032 (the end of the IRP planning horizon).

77. TEP anticipates exceeding the annual DRER in 2017 and each year thereafter in its IRP[19].

78. UNSE anticipates exceeding the annual DRER in 2017 and each year thereafter in its IRP[20].

79. AEPCO was relieved of the IRP Rules requirements related to REST compliance by Decision No. 73884. This relief was granted to AEPCO in recognition of AEPCO's unique situation as a wholesale-only energy supplier.

Energy Efficiency Standard

80. Commission Decision No. 71819 adopted a new article 24, "Electric Energy Efficiency Standards" ("Energy Efficiency Standards") in A.A.C. Title 14 Chapter 2 which became effective January 1, 2011. The Energy Efficiency Standards require 14.5 percent reduction of the previous year's retail sales for 2017 and increases to 22 percent by 2020.

81. The Energy Efficiency Standard for APS were modified in Decision No. 75679 to even out its annual Energy Efficiency requirements leading up to a cumulative load reduction of 22

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[19] TEP will meet the Residential portion of its Distributed Renewable Energy Requirement by including Renewable Energy Certificates obtained under the Track and Record method.

[20] UNSE will meet the Residential portion of its Distributed Renewable Energy Requirement by including Renewable Energy Certificates obtained under the Track and Record method.

percent by 2020 requirement. APS's IRP indicates that the Company plans on 14.18 percent cumulative load reduction in 2017; 16.74 percent in 2018; 19.34 percent in 2019; and 22 percent in 2020.

82. In 2017 TEP's target for energy savings will be 204,341 MWh, which equates to the 14.5 percent savings required by the Energy Efficiency Standard. TEP plans to maintain compliance with the Energy Efficiency Standard through 2020 when the requirements sunset. Assumptions for EE savings after 2020 indicate that TEP could potentially reduce TEP's system peak demand by 318 MW by 2032.

83. UNSE reported energy savings of approximately 12 percent for 2016. In 2017, the UNSE target for energy savings is 43,611 MWh which equates to the required 14.5 percent under the Energy Efficiency Standard. For resource planning purposes, UNSE has assumed that it will maintain compliance with the Energy Efficiency Standard through 2020 when the program sunsets.

84. AEPCO was relieved of the IRP Rules requirements related to Energy Efficiency Standard compliance by Decision No. 73884. This relief was granted to AEPCO in recognition of AEPCO's unique situation as a wholesale-only energy supplier.

Commissioner Comments

Commissioner Doug Little

85. In a letter dated June 16, 2015 in Docket No. E-00000V-15-0094 Commissioner Little proposed extending the filing date for the next integrated resource plan from April 1, 2016 to April 1, 2017.

86. Extension was proposed due to uncertainty surrounding the EPA's final Clean Power Plan. Commissioner Little asked for Utility comments regarding the proposal.

Commissioner Bob Burns

87. Commissioner Burns agreed with Commissioner Little and further proposed to extend the IRP cycle from 2 years to 3 years[21]

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[21] Letter filed on June 9, 2016 in Docket No. E-00000V-15-0094.

88. Increased time would lead to more thorough and comprehensive resource plans. Commissioner Burns requested Utility comments regarding the proposal.

89. Commissioner Burns also filed comments on July 9, 2015 in Docket No. E-00000V-15-0094 requesting comments on the proposed extension of the April 2016 IRP filing date.

90. Specifically Commissioner Burns wanted to discuss a two part filing. The first would be a preliminary filing which would occur in April 2016. The Commission would then review the IRP, ask questions and provide feedback. The final filing would occur in June 2017. Commissioner Burns also provided a timeline.

91. As previously mentioned, the comments made in response to the letters filed by Commissioner Little and Commissioner Burns resulted in Decision No. 75269, which established an alternate timeline for the IRP.

Commissioner Bob Stump

92. In his September 9, 2016 letter in Docket No. E-00000V-15-0094, Commissioner Stump stated that the following items merit a more in-depth analysis by LSEs in the final IRPs:

- LSEs should provide more information regarding how their forecasts will impact customer billing metrics.
    - LSEs should quantify the size, growth rate and associated impacts of the near-term cost shift from rooftop solar to residential ratepayers' bills.
- Provide commission with more robust resource cost comparisons illustrations. (ex. Utility-scale v. rooftop solar, demand response v. energy efficiency, etc.)
- Profiling of customer attitudes, knowledge, and preferences.
- More robust tracking of historical load forecasting performance, providing why certain forecasts were incorrect and the degree of inaccuracy (to help improve future forecasts).
- More focus on addressing peak demand reduction. Address the effectiveness of various programs in managing peak demands.

93. The LSEs provided more robust resource comparison cost illustrations as requested by Commissioner Stump. However, Staff concludes there was an insufficient amount of information that would satisfy Commissioner Stump's request regarding: historical load forecasting performance (discussed within the IRP rather than Preliminary IRPs), DSM program evaluation and effectiveness in managing peak demand, customer attitudes and preferences, and the impact of future portfolios on average bills of different ratepayer populations.

Commissioner Andy Tobin

94. In his December 6. 2016 letter in Docket No. E-00000V-15-0094, Commissioner Tobin discussed the risk management principle, which was discussed at the Commission's November 29, 2016 Special Open Meeting. Commissioner Tobin expressed the following points:

- Arizona's utilities must invest in diverse resource options to realize the affordability and reliability IRP planning principles.
- The preliminary IRPs do not achieve this balance as they are heavily weighted toward the selection of a single resource option – natural gas.
- Ignoring resources like utility scale energy storage and other innovative technologies is not in the best interests of ratepayers.
- Utilities should provide a stand-alone calculation for energy storage in future versions of their 2017 IRPs.
- Arizona has other options that support AZ jobs, are less risky, and less expensive than natural gas.
- Suggestions for the IRPs:
    - More robust levelized resource Cost Comparisons. In chart format delineating how the cost category contributes to overall cost for each resource.
    - Economic development: what the utility is doing to attract/retain companies and support in-state job creation.
    - More illustrative risk/reward tradeoffs.
    - More strategies to take advantage of low daytime pricing—how can AZ best benefit from California's over generation especially during peak periods?
    - More coverage of the distribution system—How is the grid changing (quantify needs, flexible ramping needs, non-generation alternatives to meet needs, opportunities to geo-target demand-side resources to alleviate constraints)?

95. Staff believes that the IRPs contained sufficient information regarding levelized resource cost comparisons, risk/reward tradeoffs (although they could be more illustrative), and the distribution system, as requested by Commissioner Tobin. However, Staff believes there was an insufficient amount of information in TEP's and UNSE's IRPs regarding strategies to take advantage of low daytime pricing and economic development (in the context of what the utility is doing to attract and retain companies and support in-state job creation).

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Preliminary IRPs - Stakeholder Comments

Freeport Minerals Corporation

96. TEP's discussion of the impacts of a customer opt-out program fail to address how customer opt-out load can be integrated in the IRP.

97. A permanent opt-out program would allow TEP to avoid long-term generation investment costs.

98. TEP's calculation of the short term impacts of an opt-out program is flawed and TEP's depiction of an opt-out program ignores the AECC/Noble Solutions proposal.

Interwest Energy Alliance

99. Utility-scale renewable generation should comprise a greater share of the resource mix because of improved technology, efficiency of scale, falling prices, and low uncertainty.

100. The preliminary IRPs rely too heavily on natural gas and seem too optimistic about natural gas prices.

101. Competitive procurement should be utilized more frequently for new generation resources.

102. Encourages the Commission to develop a pilot program allowing large customers and residential communities to procure a percentage of their electricity from third-party renewable providers.

Ormond Group

103. Utilities are relying too heavily on natural gas and through adjuster mechanisms, remove all risk for price increases from the utilities and place it on Arizona customers.

104. The Commission might consider asking for direct analysis on customers' bills from different natural gas price increase scenarios such as extreme, short-term price disruptions resulting from weather related events and longer-term price impacts resulting from increased international competition or supply delivery curtailments and disruptions.

105. Another line of inquiry is to ask if/how a utility would change its preferred resource portfolio if the utility shared in the risk for natural gas prices increases such as the former Arizona

Public Service Company 90 percent – 10 percent cost share requirement where the company was only allowed to pass through 90 percent of natural gas cost increases and had to absorb 10 percent.

106. Prices for renewable energy resources have never been lower and in some cases are lower than new natural gas and don't carry consumer price volatility risk. There is room to expand renewable resources instead of moving to a system where the majority of electric generation is natural gas dependent.

107. Ask utilities to study scenarios that maximize the amount of renewable energy and the system modifications necessary. For example, direct APS and other utilities to study a scenario where 75 percent of new resources are noncarbon, non-polluting, non-water consuming technology and 25 percent is natural gas. This type of "stretch" scenario would provide the Commission and stakeholders with a bookend of what is possible.

<u>TEP Customer</u>

108. TEP should not purchase any additional natural gas generating capacity and should instead procure local utility scale solar facilities, augmented by energy storage when needed.

109. Fixed cost Solar PPA's provide a much more reliable Return on Investment ("ROI") than long life natural gas fired generating assets subject to annual and significant increases in the Operating, Maintenance and fuel costs.

110. If natural gas prices increase, before the useful life, full depreciation of the gas assets, full recovery cannot be achieved.

111. Solar costs continue to decrease and offer a wide array of potential benefits.

2017 IRPs – Stakeholder Comments

<u>Calpine Energy Solutions, LLC ("Calpine") – Response to APS and TEP Plan</u>[22]

112. Calpine has participated in several proceedings relating to the potential role of alternative generation: APS 2012 rate case, UNSE and TEP's 2015 rate cases, APS 2016 rate case.

113. In 2015 UNSE rate case the Commission declined to approve a buy-through program.

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[22] September 13, 2017. http://docket.images.azcc.gov/0000182699.pdf

114. In the 2015 TEP rate case, Calpine and Arizonans for Electric Choice and Competition ("AECC") jointly proposed an alternative generation service program, modeled on the APS AG-1 program. The Commission declined to approve either a buy through or opt out alternative.

115. Calpine asserts that the "results are in" with respect to the AG-1 Program, as a Settlement Agreement in the 2016 APS rate case was adopted by the Commission in Decision 76295. In this agreement the AG-1 program has been succeeded by an alternative generation service buy-through program for large commercial and industrial customers, to be known as AG-X.

116. Calpine notes that during the August 15, 2017 meeting, Chairman Forese, in explaining his vote that the Forthcoming AG-X program could have a significant positive impact on future economic development within the APS service area.

117. Calpine notes that the instant proceeding offered the opportunity to comment during the time period April 4, 2017 and September 30, 2017. Calpine deferred filing comments until after the TEP and APS rate cases were concluded.

118. Calpine supports the AECC comments on both APS and TEP's IRP filings.

119. Calpine believes that the rapidly changing nature of the electric utility industry in Arizona and the ever increasing need to be responsive to the changing needs of customers now requires the Commission to assume a proactive role in communicating to the electric utilities various options it would like them to consider incident to their planning. Accordingly, Calpine supports the inclusion of the two recommendations of the AECC in the forthcoming acknowledgement of the APS and TEP 2017 filings.

<u>TEP – Response to Comments Filed by Calpine Energy Solutions, LLC</u>[23]

120. The settlement agreement approved in the APS rate case (see Decision No. 76295 (August 18, 2017)) resulted in a negotiated rate rider AG-X. The majority of the terms and conditions of the AG-1 and AG-X tariffs are substantially similar.

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[23] September 21, 2017. http: docket.images.azcc.gov 0000182862.pdf

121. Given the similarities, and the fact that there was no cost of service evidence or any other vetting of either the AG-1 or AG-X programs, TEP argues that the results are not clear.

122. Until an in-depth analysis of these programs is presented on the record within an APS general rate case that does not result in a settlement, it is not clear what the actual impact will be on non-participating customers.

Calpine – Reply to TEP Comments[24]

123. TEP assumptions selectively designed to support its underlying opposition to any form of third-party alternative generation service include:

124. The belief that Stranded Cost exit fees for such programs are per se equivalent in duration to the Company's then remaining generation plant(s) operating life.

125. An assumed inability by the Company to effectively compete for energy purchases from the low cost wholesale power markets.

126. An assumed high level of risk that alternative generation service customers would elect to return to such service from TEP rather than commit to market risk over the long-term.

127. The apparent belief that cost recovery criticisms voiced by APS in mid- 2016 would necessarily be inherent in any continued or future form of buy-through or opt-out program.

Freeport Minerals Corporation and Arizonans for Electric Choice and Competition – Response to APS' Plan[25]

128. The APS IRP was filed four months before the Commission approved the AG-X program. APS was not obligated by the Settlement Agreement and Decision to integrate it into its IRP. Freeport is not asking that the AG-X program be incorporated into the 2017 IRP.

129. Freeport believes that in future IRPs APS and the Commission can focus on the role such programs can play in mitigating the need for additional supply side resources.

130. There may be opportunities to expand the AG-X program in later years, albeit incrementally and subsequent to a future rate case.

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[24] September 29, 2017. http: docket.images.azcc.gov 0000182970.pdf
[25] September 8, 2017. http: docket.images.azcc.gov 0000182627.pdf

131. Freeport urges the Commission to make consideration of alternative generation programs a regular part of the analysis in subsequent IRPs.

Freeport Minerals Corporation and Arizonans for Electric Choice and Competition – Response to TEP's Plan[26]

132. The parties request that the Commission require TEP to conduct a thorough study on the role that buy-through or opt-out programs similar to APS AG-X can have on TEP resource planning. Interested stakeholders can then present evidence whether such programs will benefit consumers and the broad public interest.

133. Alternative generation is not novel, citing APS, Texas and Oregon.

134. TEP did not analyze how a buy-through or opt-out program might alleviate the need for more natural gas capacity.

135. TEP did not include this analysis in the section "A New Integration Approach to Resource Planning". (Page 26 of the final TEP IRP).

136. Between potential displacement of TEP renewable capacity and projected reserve deficiency TEP could accommodate by-through or opt-out much larger than 60 MW.

137. TEP has contracted to sell 44 MW of capacity and 400 GWhs of energy to Navopache. No fixed generation costs are allocated to this contract, and 100 percent of profits will flow to TEP shareholders.

138. The timing for the evaluation of the role that alternative generation programs can have in meeting needs is now.

139. TEP should be required to supplement its IRP with detailed information about potential alternative generation programs, with different sizes (i.e. between 60-200 MW) so all parties and the Commission will have the information necessary to fully address the issue in TEPs next rate case.

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[26] September 8, 2017. http: docket.images.azcc.gov 0000182628.pdf

TEP – Response to Comments Filed by Freeport Minerals Corporation and Arizonans for Electric Choice and Competition[27]

140. TEP has reviewed the transcript and video of the February 8, 2017 Open Meeting and did not find that the Commission instructed the Company to address the role of a buy-through or opt-out program in the 2017 IRP.

141. There was a limited discussion about the potential to use the integrated resource planning docket as an alternative for the TEP to study the impacts of a buy-though tariff.

142. The Commission never directly asked TEP if it would be willing to commit to conduct a buy-through or opt-out program analysis of its 2017 IRP.

143. TEP submitted an analysis regarding opt-out or buy-through programs in its Supplement to its Preliminary IRP filing on October 1, 2016.

144. Further analysis with a more defined proposal and the ability to identify specific impacts on TEP and its customers is more appropriate for a rate case.

Interwest Energy Alliance – Response to APS' Plan[28]

145. APS' IRP makes incorrect assumptions regarding the current and future capital cost of utility-scale solar photovoltaic systems.

146. APS' forecast of natural gas prices does not include even modest sensitivity analysis with respect to gas prices. Sensitivity analyses would likely demonstrate that APS' overreliance on natural-gas resources unnecessarily exposes its rate-paying customers to price increases. This Commission should be particularly sensitive to APS' overly optimistic natural gas forecast following the Commission's agreement to remove the cost sharing provision for APS' Power Supply Adjustor several years ago.

147. The IRP fails to account for the operational capabilities of utility-scale solar, which already provide a cost-effective and efficient alternative to many of the services the plan assumes must be provided by natural gas resources.

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[27] Comments filed on September 21, 2017. http:__docket.images.azcc.gov_0000182862.pdf
[28] September 8, 2017. http:__docket.images.azcc.gov_0000182644.pdf

148. The IRP does not account for the rapidly emerging PV and storage market, which could provide an economically and environmentally preferable alternative to combustion resources.

149. The IRP assumptions about the rate of adoption of residential solar PV are highly uncertain at a time when APS' modifications to its net metering tariffs and phased down federal tax benefits are likely to operate as a disincentive to such adoption over the planning period.

150. APS mistakenly assumes that current conditions in the Western energy markets, which have led to sporadic sales of low- and negatively-prices solar in limited hours, will persist indefinitely, when, in fact, both technical and systemic remedies are already being adopted by project operators, the California Independent System Operator and system planners.

151. The IRP incorrectly assumes that wind resources are limited in Arizona, and does not accurately consider high-quality, low cost wind resources available in the region.

152. The Commission should schedule workshops to discuss APS' assumptions, model outputs, modeling methodologies, and reasonable foreseeable potential errors introduced by the selected approaches.

153. A more rigorous, thorough, and transparent approach to resource planning is necessary.

Sierra Club ("SC") – Response to TEP's Plan[29]

154. TEP's planning processes are neither robust nor complete and fail to explain ratepayer risks, and use stale data.

155. TEP's portfolios are narrow in scope, do not test a reasonable range of assumptions or futures and obscure the value proposition of alternative energy resources.

156. TEP's IRP fails to comply with the requirements of A.A.C.R 14-2-703(F); it does not demonstrate that the finalized portfolio is based upon a comprehensive consideration of a wide range of supply-and-demand-side options, fails to manage uncertainty and risks associated with TEP's current fleet, and fails to provide evidence that it achieves a reasonable long-term total cost.

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[29] September 27, 2017. http://docket.images.azcc.gov/0000182930.pdf

157. TEP's assumptions regarding its coal plants and the economic risks associated with near term retirements are insufficient.

158. TEP dismisses the capacity value of primary renewable energy resources and dismisses the potential of these options to contribute to the TEP's reserve margin. TEP improperly evaluates timing of solar energy relative to demand, and the rapid response required to meet fluctuating solar.

159. TEP understates the amount of energy efficiency available to TEP and incorrectly assesses incremental energy efficiency as a cost, rather than a net incremental value, by use of an inconsistent valuation methodology. TEP, inconsistently with its assessment of other resources, assessed the up-front costs but failed to account for long term benefits. TEP's "expanded efficiency case plan" ultimately saves the company just under 20 percent of retail load by 2032 instead of 17.5 percent in the reference case. This is not a substantial increase in EE savings, and it is unreasonable to consider this expanded or aggressive efficiency.

160. TEP undervalues the role of battery storage, and the IRP lacks cost assumptions for future battery storage, and fails to include other value propositions for grid-scale storage, including ancillary services.

161. TEP's assessment of the Clean Power Plan's requirements is flawed and inconsistent with reasonable risk aversion practices.

162. TEP's IRP planning process is one of the least transparent and least valuable to regulators and stakeholders among those conducted by large utilities.

163. The Portfolios studied are "non-optimized" and provide no explanation how the portfolios were developed.

164. The alternative portfolios are neither robust nor reasonable.

165. Sierra Club makes the following recommendations.

166. TEP should be required to revise its modeling and scenarios to capture a wider range of scenarios, future outcomes and potential portfolios. TEP should be required to use some form of optimization modeling or be compelled to provide detailed assessments of its resource choices in the scenarios provided.

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167. TEP should be required to assess the economic value of Springerville 1 and 2, separately. This valuation should include a risk assessment for coal and market prices, carbon regulation, CAISO market integration and integration with substantial renewable buildout.

168. The Commission should not approve RFPs for new gas resources based on long term assumptions of load growth, particularly the proposed 2011 combined cycle plant in the reference case. The Commission should demand a rigorous analysis of need and alternatives, including optimized portfolios, prior to giving even implied approval of the new facility.

169. TEP should be required to rigorously model expanded renewable scenarios, in which substantial renewable energy, above the amounts in the reference case, are obtained and balanced by TEP.

170. TEP should account for the full lifetime savings of energy efficiency measures in its modeling and should not assume that cost-effective energy efficiency programs will be unavailable after 2020.

171. TEP should rigorously account for the ancillary and capacity values provided by already contracted and potential battery storage in determining the need for NGCC and RICE capacity.

TEP – Response to Comments Filed by Sierra Club[30]

172. SC advocates for commitments to certain technologies long before the information necessary to make such decisions can be reliably known.

173. SC wrongfully states that there is no explanation in the IRP how the portfolios were developed. This information is provided in several parts of the IRP, which TEP cites. The planning process was robust and transparent.

174. The IRP meets all of the criteria of the requirements of A.A.C. R14-2-703 (F). SC statements regarding "three key stages in any electric resource planning process are not aligned with the Commission's IRP rules. TEP provides a review of the requirements for a Reference Case

[30] October 10, 2017. http://docket.images.azcc.gov/0000183141.pdf

Portfolio in the IRP rules, and citations in the IRP to TEP's compliance with the rules regarding the components of the Reference Case Portfolio.

175. TEP disputes the SC criticism of its planning process. SC confuses "lowest cost", which is not in the IRP rules with "reasonable cost" which is used in the IRP rules. SC also overlooks the complexity involved in resource choices and how this is recognized in the IRP rules. TEP provides an outline of its methodology to develop its Reference Case Portfolio. TEP states it used a logical series of steps and a rigorously documented series of assumptions using high level screening tools followed by the use of an hourly production cost model to develop its Reference Case Portfolio.

176. TEP provides information and citations regarding the source of data in its planning process, noting that the Appendix A to its IRP plan contains a December 2016 report that it used to develop future scenarios.

177. SC's claims that TEP failed to adequately address its Coal Resource Planning issues lacks merit. The Executive Summary in the IRP demonstrates that TEP acknowledges the changing role of coal fired generation. TEP summarizes its retirement commitments relating to Sundt, San Juan Units 1 and 2, and Navajo Generating Station, and its assessment regarding the acquisition of Springerville Unit 1 capacity.

178. SC's statement that TEP's planned expansion of renewable energy to serve 30 percent of retail load as "modest" is not supported by facts. The DSIRE[31] website shows that TEP's goal of 30 percent by 2030 meets or exceeds the standards of most states.

179. SC's comments regarding TEP's method for assigning peak capacity is a key factor in limiting TEP's renewable energy buildout are incorrect. TEP assigns a relatively high coincident peak value to solar resources.

180. SC is wrong to characterize renewable energy resources as a replacement for coal, and demonstrates a lack of understanding of the basic function of dispatchable resources.

181. SC's comments that TEP's treatment of Energy Efficiency has two substantial flaws are flatly wrong. TEP treats EE as a demand-side resource which entails modeling EE consistently

[31] TEP states that DSIRE is the most comprehensive source of information on incentives and policies that support renewables and energy efficiency in the United States.

with supply-side resources. SC's suggestion that TEP use "lifetime costs" pretends that the costs to achieve energy savings accrue in the same year that savings occur, by spreading the costs evenly over the lifetime of the measure is completely inconsistent with how all other supply-side resources are modeled.

182. SC's comments on battery storage are not accurate. SC apparently misinterpreted a chart in the IRP concluding that the chart indicates that the reference case assumes that TEP will only have 30 MW of battery storage by 2020 (in addition to its existing 5 MW). This chart values actually represent resource contribution to system peak; the assumed full amount of battery storage by 2030 is 220 MW.

183. SC's characterization of how TEP deals with the considerations inherent in the Clean Power Plan is wrong. The Clean Power Plan is still a final adopted rule with a clear CO2 emission mitigation methodology and remains in effect, and is therefore an appropriate surrogate for gauging TEP's condition relative to future CO2 mitigation requirements. Using any other targets would be highly speculative.

Sierra Club – Response to APS' Plan[32]

184. APS has an unrealistically high load forecast which is nearly identical to the forecast used and rejected in 2014.

185. The IRP has a systemic bias against demand-side management alternatives. APS incorrectly uses customer energy efficiency costs in its calculation of net present revenue requirements.

186. APS provides inadequate justification for its portfolio selection. The Carbon Reduction portfolio provides a benefit of over $200 million relative to the selected portfolio over the long term, while also resulting in lower emissions and water usage. APS failed to provide a transparent description of how APS weighted its key metrics.

187. APS overstates the future costs of available solar and wind resources, ignoring both the current low cost of renewables and ongoing cost declines.

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[32] September 27, 2017. http: docket.images.azcc.gov 0000182931.pdf

188. APS undervalues battery storage by assuming inflated battery storage costs and understating the potential for batteries to provide near-term cost-effective peak capacity and ancillary services. APS erroneously states that battery storage may not even be feasible within the next ten years, despite recent procurement of cost-effective storage by APS and other Arizona Utilities. This biases it against one clear alternative to APS' pursuit of extensive new natural gas capacity.

189. APS assumes long-term gas prices that are lower than even the lowest sensitivities evaluated by other, standard long term forecasters. The gas price sensitivities are not sufficiently spread out to reasonably assess exposure to gas price risk. These assumptions bias the IRP in favor of the construction of natural gas capacity.

Sierra Club Recommendations:

190. APS should submit a revised IRP that:

191. Includes a credible load forecast and does not depend on rapid load growth that is unlikely to materialize.

192. Corrects for the erroneous inclusion of participant demand-side management costs in its assessment of the revenue requirements of alternative scenarios.

193. Account for the current low costs, and likely future declines in the costs of renewable and battery storage resources.

194. Incorporates gas prices and load forecast sensitivities which cover a more reasonable range of likely futures.

195. Provides a greater transparency around its portfolio selection process.

196. APS should withdraw its recently released RFP for up to 700 MW of new capacity.

197. APS should pursue all cost-effective energy efficiency and should not dismantle its current efficiency programs simply because it believes they will not be required by law after 2020.

198. APS should investigate near-term opportunities to invest in cost-effective renewable and battery storage resources.

199. APS should conduct a detailed study of the economic viability of each of its remaining coal units.

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Southwest Energy Efficiency Project's Response to APS' Plan[33]

200. The resource portfolio selected by APS is bad for customers and is not in the public interest because it increases both cost and risk significantly, and more than is necessary to deliver reliable energy resources to meet customer needs.

201. APS' Selected Portfolio is weighted too heavily towards costly supply-side resources. The analysis presented in the IRP is biased in favor of these resources, and is biased against demand-side resources that would lower overall costs to customers.

202. A resource portfolio with more demand-side resources would outperform the APS Selected Portfolio on virtually every relevant metric, including costs to customers.

203. APS' natural gas plant buildout under the APS Selected Portfolio creates a significant new "cost shift" that would transfer $2.9-4.1 billion ("NPV") from its customers to APS' investors and the federal government.

Southwest Energy Efficiency Project's Recommendations:

204. The Commission should reject and should not acknowledge the APS 2017 (i.e. 2015-2016) Integrated Resource Plan.

205. The Commission should explicitly reject APS' proposed approach to reduce deployment of demand-side resources after 2020.

206. The Commission should require APS to select and implement a resource portfolio, as an improved Selected Portfolio, with fewer MW of supply-side, natural gas resources and more MW of demand-side resources.

207. The Commission should require APS to use the Expanded DSM Portfolio as a floor for the level of DSM resources in the improved Selected Portfolio.

208. The Commission should order APS to address these issues in its next IRP.

209. The Commission should prioritize its actions to ensure prudent resource decisions are made in the near term.

. . .

[33] October 16, 2017. http: docket.images.azcc.gov 0000183250.pdf

210. The Commission should order APS to modify its Near-term Action Plan to include additional DSM investment after 2020.

TEP – General Comments Regarding Buy-Through and Opt-Out Programs[34]

211. TEP does not believe that buy-through or opt-out programs that were proposed in the APS settlement would provide TEP with any long-term value within the current IRP planning process.

212. The next option for the Commission to fully and appropriately consider buy-through or opt-out program and establish rates for such program is TEP's next rate case.

213. Any additional analytical work done in the current IRP would be outdated by the time of the next rate case and TEP would need to rework the analysis to reflect future changes in load growth, wholesale market conditions, and TEP's future capacity requirements.

214. TEP requests that the Commission not require the Company to submit any additional analysis on buy-through or opt-out programs as part of the 2017 IRP and defer any such analysis to TEP's next IRP so it can be timed to more closely coincide with TEP's next rate case.

2017 IRPs - Staff Comments

215. During Staff's review of the 2017 IRPs, forecasted costs of various technologies was an area of specific inquiry and review. Based on the review, Staff believes LSEs should include in their portfolio analyses the forecasted change in costs of both established technologies and emerging technologies.

216. The LSEs provided various graphical and tabular representations for each of the portfolios that were analyzed, which Staff found extremely useful and beneficial in its review of the 2017 IRPs. APS provided a table which displayed a breakdown by capacity and energy mix contributions for each portfolio that was analyzed[35]. LSEs should provide a similar table in future IRPs, although with additional information included. Specifically, LSEs should include a breakdown of each specific technology type, listed under a given resource that was included in the portfolio analysis. The breakdown should include the name of the technology (i.e. "Aeroderivative Gas

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[34] September 21, 2017. http: docket.images.azcc.gov 0000182862.pdf
[35] Table ES-2 on Page 13 of APS' 2017 IRP. http: docket.images.azcc.gov 0000178832.pdf

Turbine" listed under "Natural Gas", "Combined Cycle" listed under "Natural Gas", "Utility Scale Solar – Thin Film Solar PV – Fixed" listed under "Renewables", "Rooftop Solar PV" listed under "Renewables", etc.), its capacity contribution to the portfolio, the cost per MW of that particular technology, and the total cost.

217. The various portfolios that are analyzed by each LSE are of great interest to Staff and various stakeholders. It may be beneficial for LSEs to collaborate with Staff to conduct a workshop for the sole purpose of discussing each portfolio that is being analyzed in the LSEs' IRP. Specifically, the modeling assumptions (i.e. reasons why certain technologies were selected and the associated costs), the modeling outputs, and modeling methodologies could be discussed at such a workshop.

218. The reported results, provided by the LSEs, from each of the studied scenarios are valuable and provide the Commission with insight regarding the cost, feasibility, and effects of implementing each scenario. Going forward, it may be beneficial for utilities to further study resource mixes with more emphasis on natural gas price sensitivities.

219. After a period of high and volatile natural gas prices in the early 2000s, natural gas prices have been much lower and less volatile, largely due to the introduction of large volumes of inexpensive shale gas, in the last decade. Further, significant proven and technically recoverable natural gas reserves exist in the United States. But the level and volatility of the price of natural gas is very uncertain in the long term future as a variety of factors domestically and internationally can exert upward or downward pressure on prices. Combined with Arizona's growing reliance on natural gas generation in recent decades and the expectation that such dependency will grow in the future, natural gas pricing issues are a key driver in future resource planning decisions by Arizona utilities. Thus a very robust sensitivity analysis, considering a wide variety of natural gas price scenarios, should be a cornerstone of utility resource planning in Arizona.

220. With further study of resource mixes, utilities could identify optimum resource mixes between natural gas, renewables, and DSM which could reduce customer risk to unexpected changes in natural gas prices. As a result, there may exist scenarios which have slightly higher costs but whose diversification can provide a cushion from risks associated with natural gas pricing in the future.

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221. As Arizona LSEs become more dependent on natural gas-fired generation, the lack of market area natural gas storage in Arizona becomes more of a concern. Natural gas storage can provide utilities a variety of benefits including greater reliability, assistance in black start situations, more efficient management of pipeline capacity, avoidance of pipeline penalties, and hedging opportunities. Staff believes that utilities should address natural gas storage in greater detail in future IRPs, including a discussion of efforts to develop natural gas storage, the costs and benefits of natural gas storage, and risks resulting from a lack of market area natural gas storage in Arizona.

222. Energy efficiency mandates that apply to public service corporations that provide electric services in Arizona, expire in 2020[36]. The Rules do not provide for any energy efficiency savings beyond that date and the IRP process applies only to Load Serving entities[37]. AAC R14-2-703 (F) (6) requires that IRP plans "... address energy efficiency so as to meet any requirements set in rule by the Commission or in an order of the Commission." LSEs have considered energy efficiency as a resource in their IRPs. In docket No. G-01551A-15-0168, the Application of Southwest Gas Corporation for Approval of an Energy Efficiency and Renewable Energy Resource Technology Implementation Plan, Staff identified options for addressing the issue of the expiration of the Energy Efficiency Rules which include; suspending or updating the Rules, establishing IRP goals in rate cases, and making Energy Efficiency and Demand Response a part of the IRP process. Staff noted that not every utility is required to file an IRP. In order to incorporate Energy Efficiency and Demand Response into IRP, more utility stakeholders would need to participate in the IRP process or "non-generation" utilities may require a streamlined IRP process. As a result, Staff recommended that one or more EE workshops be held to allow stakeholders to provide input on the options. Staff renews that recommendation in this docket.

223. Decision No. 76295[38] ordered APS to demonstrate that analysis of resource and system upgrade options includes a storage alternative when APS acquires any new resource or transmission or distribution upgrade where appropriate. "In the analysis, APS must demonstrate that it reasonably

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

[37] A Load Serving Entity is defined 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. AAC R14-2-701 (26).

[38] APS Rate Case Docket No. E-01345A-16-0036. Pages 112-113. http://docket.images.azcc.gov/0000182160.pdf

considered all of the costs and benefits of each resource or system upgrade option, allowing for comparisons to be made on similar terms and planning assumptions. Energy storage shall also be included as a resource option in any analysis of baseload resources as well as any analysis of non-baseload resources." Decision No. 76295 further states, "APS shall include accurate cost data in its modeling assumptions… APS shall account for the forecasted decline in energy storage costs and ensure that storage resources are modeled in such a way that the IRP model captures their impact. Costs shall also be transparent by providing the cost of each technology with and without state and federal tax incentives and/or credits. APS shall also identify and analyze a reasonable, representative range of storage technologies and chemistries." This analysis should be a component of all LSE's future IRPs and should be clearly discussed within each IRP.

3-Year IRP Cycle - Stakeholder Comments

224. Several stakeholders voiced concerns regarding the IRP process at the Workshop meetings and in written comments filed in the docket. The nature of stakeholder concerns covers a broad spectrum, including the following:

<u>APS</u>

225. 3-Year cycle would reduce resource demands on the Commission and utilities in IRP preparation.

226. However, the 2-year cycle promotes a dialogue and timeliness which improves the transparency the Commission and stakeholders have requested.

<u>Ormond Group</u>

227. A schedule of biennial filings is typical in the industry and is appropriate in the current situation. The ACC process of three year actions plans is also appropriate to provide input to the utilities.

228. The Commission can make the resource planning process more robust and useful if it directs future scenarios for study that are in the public interest, then hosts a discussion about the pros and cons of those scenarios to help influence utility decision-making.

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Southwest Energy Efficiency Project ("SWEEP")

229. SWEEP is willing to consider a longer cycle but only after recent IRP improvements have implemented and assessed.

230. SWEEP is concerned that a longer cycle may not accommodate rapidly emerging technologies.

231. 3-year cycle will not provide adequate frequency of information.

TEP

232. The companies (TEP & UNSE) are open to a longer IRP cycle.

233. Changing the IRP frequency will require a rulemaking action.

Western Grid Group

234. The 2-year cycle should be maintained.

235. The IRP is the only source of information of the overall view of possible future resource scenarios.

236. Considered the speed of technology growth, a 3-year gap in this information is not ideal.

Stakeholder Recommendations

237. The majority of stakeholders filing comments in this docket also offered recommendations for addressing concerns and improving the IRP process. Staff commends the stakeholders for their timely and informed comments and suggestions. The stakeholder recommendations are summarized as follows:

Arizona Committee for Compressed Air Energy Storage ("ACCAES")

238. Arizona's solar potential is immense and without compressed air energy storage ("CAES"), Arizona can only become a local supplier of intermittent solar power. With CAES, Arizona has a unique opportunity to lead the nation to true energy independence.

239. The ACC and utilities should consider ACCAES's plan to develop Arizona's first independent PV-CAES plant, linked to new or existing solar PV farms or other forms of generation. It overcomes limitations of geographically constrained hydropower or expensive and capacity-limited technologies like batteries.

240. ACCAES proposes to establish a private firm to develop and to provide Arizona's first CAES unit, a utility-scale 300 MW PV-CAES plant, to be used for energy arbitrage, primarily in the role of providing dispatchable solar power to the community.

241. ACCAES request that the ACC grant them authority to establish a public or privately owned utility storage facility which may have other Arizona Utilities as partners. ACCAES foresees the ACC setting storage rates as it does for other utilities.

TEP

242. Future clean energy targets should be developed on a utility-by-utility basis. Clean energy standards applied at a statewide level are inherently inflexible, and fail to take into account the unique circumstances of each utility. This inflexibility creates inefficiencies in resource acquisitions and system dispatch, which ultimately results in higher costs passed on to customers. TEP believes that the IRP is a better mechanism to develop utility specific clean energy targets than a state-wide, "one size fits all" Rulemaking.

Vote Solar

243. Suites of aggregated distributed energy resources ("DERs") should be considered as alternatives to generation, transmission and distribution investments. Utilities should identify plans for leveraging capabilities of DERs in deferring or avoiding transmission and distribution investments and improving reliability.

244. Each utility should identify the assumptions behind the forecast of customer adoption of DG. The impact of proposed utility rate design proposals on DG penetration should be discussed in the IRPs.

245. The following scenarios should be included in the IRPs; adoption of a mass-based compliance approach to the Clean Power Plan, adoption of a rate-based compliance approach to the Clean Power Plan, early retirement of aging coal power plants, high levels of customer-driven DER penetration, high levels of energy efficiency and demand response, high level of adoption of electric vehicles, participation in EIM (TEP and UNSE) and full participation in regional ISO day ahead and real time energy markets (all utilities), and limitations on water use at thermal power plants due to climate stress.

246. Three-year action plans should include capital plans for upgrades to the transmission and distribution systems in addition to new sources of generation.

247. The process for reviewing the utility preliminary IRPs should provide for several opportunities for stakeholders to review both Commission guidelines and each utility's proposed plans.

Assessment Conclusions

248. Decision No. 75269 instituted additional requirements to the IRP process for APS, TEP and UNSE. These LSEs were required to file Preliminary IRPs by March 1, 2016, and to provide updates to their IRPs by October 1, 2016. AEPCO was required to file its preliminary IRP by September 1, 2016. Decision No. 75269 made pre-filing workshops for the Preliminary IRPs optional. APS held a pre-filing stakeholder workshop on February 9, 2016 before filing its Preliminary IRP on March 1, 2016[39]. TEP and UNSE filed their Preliminary IRPs on March 1, 2016 and AEPCO filed its Preliminary IRP on September 1, 2016[40,41,42]

249. Although Decision No. 75269 contemplated the possibility of Commission proceedings at Open Meetings for review of the Preliminary Plans, the Commission elected not to schedule such proceedings. However, on July 18, 2016, the Commission held a workshop on the Preliminary IRPs filed by APS, TEP, and UNSE.

250. On September 30, 2016 APS, TEP, and UNSE each filed a supplement/update to their Preliminary IRP.

251. Both Decision No.75269 and Decision No. 75068 required APS, TEP and UNSE to provide opportunities for stakeholder and public review before the filing of the final IRPs. TEP and UNSE held a stakeholder workshop on November 2, 2016 to share information related to key planning assumptions that were used in the development of their IRPs. APS held a stakeholder workshop on November 18, 2016 to provide a forum to discuss planning considerations in preparation for its 2017 IRP.

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[39] APS Preliminary IRP. http: docket.images.azcc.gov 0000168766.pdf
[40]TEP Preliminary IRP. http. docket.images.azcc.gov. 0000168772.pdf
[41] UNSE Preliminary IRP. http: . docket.images.azcc.gov. 0000168775.pdf
[42] AEPCO Preliminary IRP. http. . docket.images.azcc.gov 0000173152.pdf

252. On March 8, 2017, APS filed a request for a one week extension of the April 3, 2017 deadline in Decision No. 75269 to file its 2017 IRP. On March 30, 2017, AEPCO filed a request for extension of the filing date for its 2017 IRP. Both extensions were granted by the Commission.

253. On April 3, 2017, TEP and UNSE each filed their 2017 IRP. On April 10, 2017, APS filed its 2017 IRP and on May 3, 2017, AEPCO filed its 2017 IRP.

254. A total of three parties filed notices to become a party in the proceeding: Freeport Minerals Corporation, Arizonans for Electric Choice and Competition, and the Sierra Club. In addition, the Residential Utility Consumer Office and Southwest Energy Efficiency Project filed an application to intervene.

255. Staff believes that the 2017 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). Staff believes the IRPs of APS, TEP and UNSE meet the requirements of the Commission's IRP rules and prior relevant Decisions, and recommends that the Commission acknowledge the IRPs of these companies. However, Staff would like to bring attention to the following:

APS

256. APS' forecasted load growth and customer growth appears to be too aggressive given the information contained in the 2017 IRP and prior IRPs. Specifically, the total load requirement in 2012 was given as 8,233 MW[43] while the load requirement listed in the 2017 IRP was roughly 8,000 MW[44], indicating relatively small load growth spanning the six year period (2012-2017). In addition, APS stated that it expected to add 600,000 customers by 2027 in its 2012 IRP and also stated that it expected to add 550,000 customers by 2032 in its 2017 IRP. However, according to its Historical Resource Planning report for 2016, APS has added approximately 11,909 customers per year on average for the past ten years (2007 – 2016)[45]. In order to achieve a customer growth of 550,000 or 600,000 within a 15-year planning period, APS would have to add, on average, approximately 36,666 customers each year (versus the historical addition of 11,909 customers per year).

[43] Table 2 on Page 6 of APS' 2012 IRP. http: docket.images.azcc.gov 0000135557.pdf
[44] Figure 1-2 on Page 33 of APS' 2017 IRP. http: docket.images.azcc.gov 0000178832.pdf
[45] Page 33. http: docket.images.azcc.gov 0000178578.pdf

257. APS's selected plan assumes a retirement of Cholla Units 1 and 3 in 2024 and APS is continuing to evaluate its options related to Cholla. APS is taking proactive measures in regard to monitoring natural gas prices, the economics of retiring Cholla, and future carbon legislation. If the selected resource plan is modified as a result of monitoring these key variables, APS will provide such information in an update to its 3-Year Plan.

258. It appears that the alternate timeline of the current IRP cycle was beneficial by allowing increased stakeholder participation. APS studied two additional portfolios (the Carbon Reduction and Resource Mandates Portfolios) based on stakeholder suggestions provided during the Stakeholder Forums held by APS in February and November 2016.

<u>UNSE</u>

259. UNSE has stated that, "going forward, rather than focusing specifically on summer peaking requirements, UNSE intends to transition from conventional peak shaving DR programs to more advanced DR programs that are capable of cost effectively addressing grid balancing needs such as short-run ramps and disturbances at timescales ranging from seconds up to an hour, throughout the year." UNSE should provide a general discussion regarding this transition and its results in its next IRP.

<u>AEPCO</u>

260. Staff finds that the information provided by AEPCO satisfies the requirements established in Decision No. 73884.

<u>ALL LSEs</u>

261. Staff finds that the information provided by each LSE satisfies the requirements established in Decision No. 73884 and Decision No. 75068.

Staff Recommendations to Improve the IRP Process Based on Staff and Stakeholder Concerns

262. The concerns presented by Staff and the various stakeholders offer a number of opportunities to possibly "fine tune" and improve the existing IRP process. Staff has prepared a list of recommendations that attempt to address the concerns enumerated by parties to this docket:

. . .

263. The LSEs should be ordered to include in their portfolio analyses the forecasted change in costs of both established technologies and emerging technologies.

264. The LSEs should be ordered to include a tabular representation that provides a breakdown by capacity and energy mix contributions for each portfolio that was analyzed, similar to Table ES-2 on Page 13 of APS' 2017 IRP. The table should include a breakdown of each specific technology type, listed under a given resource that was included in the portfolio analysis. The breakdown should include the name of the technology (i.e. "Aeroderivative Gas Turbine" listed under "Natural Gas", "Combined Cycle" listed under "Natural Gas", "Utility Scale Solar – Thin Film Solar PV – Fixed" listed under "Renewables", "Rooftop Solar PV" listed under "Renewables", etc.), its capacity contribution to the portfolio, the cost per MW ($ Per MW) of that particular technology, and the total cost.

265. The LSEs should be ordered to coordinate with Staff to hold a public workshop within 60 days after filing future preliminary IRPs, for the sole purpose of discussing each portfolio that will be analyzed by the LSEs. Specifically, the modeling assumptions (i.e. reasons why certain technologies were selected and the associated costs), the modeling outputs, and modeling methodologies could be discussed at the workshop. This would allow further transparency for stakeholders to review assumptions and inputs regarding the various portfolios.

266. The LSEs should be ordered to address natural gas storage in greater detail in future IRPs, including a discussion of efforts to develop natural gas storage, the costs and benefits of natural gas storage, and risks resulting from a lack of market area natural gas storage in Arizona. In addition, natural gas pricing issues are a key driver in future resource planning decisions by Arizona utilities. Thus a very robust sensitivity analysis, considering a wide variety of natural gas price scenarios, should be a cornerstone of utility resource planning in Arizona. Consequently, the LSEs should be ordered to include a wide variety of natural gas price scenarios in future IRPs.

267. After considering the comments filed in the Docket, and based on the experiences encountered during the most recent 3-year IRP cycle, Staff believes that expanding the IRP process to a three year cycle, with the requirement for Preliminary IRPs, provides more opportunity for

stakeholder input and is therefore in the public interest. Accordingly, Staff recommends that the Commission order Staff to begin the process to change the existing IRP rules.

268. Staff also recommends that the Commission establish a defined comment period of 90 days from the date of the filing of the final IRP Plans in order to allow Staff sufficient time to thoroughly analyze and evaluate the comments prior to the preparation of the Staff Report and proposed order.

269. In order to address the future expiration of Energy Efficiency mandates, Staff recommends the Commission order Staff to conduct one or more EE workshops to allow stakeholders to provide input regarding the future of EE beyond the 2020 expiration date.

270. Decision No. 76295[46] ordered APS to demonstrate that analysis of resource and system upgrade options includes a storage alternative when APS acquires any new resource or transmission or distribution upgrade where appropriate. APS must also demonstrate that it reasonably considered all of the costs and benefits of each resource or system upgrade option, allowing for comparisons to be made on similar terms and planning assumptions. It was further ordered that energy storage shall also be included as a resource option in any analysis of baseload resources as well as any analysis of non-baseload resources. In addition, Decision No. 76295 further ordered APS to include accurate cost data in its modeling assumption and to account for the forecasted decline in energy storage costs and ensure that storage resources are modeled in such a way that the IRP model captures their impact. It was further ordered that costs shall also be transparent by providing the cost of each technology with and without state and federal tax incentives and/or credits. APS was also ordered to identify and analyze a reasonable, representative range of storage technologies and chemistries. This specific analysis, ordered in Decision No. 76295, should be a component of all future LSE's IRPs and should be clearly discussed within each IRP.

271. Due to Staff and Stakeholder concerns regarding APS's forecasted load growth, Staff recommends that APS be ordered to file a report, in the instant Docket, justifying its 2015 and 2016 IRP load growth projections. Said report shall also include an analysis of (A) a "no growth" scenario;

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[46] APS Rate Case Docket No. E-01345A-16-0036. Pages 112-113. http://docket.images.azcc.gov/0000182160.pdf

and (B) a "low growth" scenario (<1-percent growth) and the resultant implications on APS's resource selections under each scenario. APS shall also include a discussion regarding how each of the required scenarios affect its Three Year Action Plan. This report shall be docketed by APS within 90 days of the Commission's Decision in this matter.

272. All LSEs shall include "no-growth" and "low growth" (<1 percent growth) scenarios in future IRP Plans, until further order of the Commission.

273. As a result of TEP's recent decision to purchase the output of Unit 2 at the gas-fired Gila River Power Station[47], Staff recommends TEP file an update to its Three-Year Action Plan within 30 days of the Commission's Decision in this Matter.

274. Staff recommends that the Commission acknowledge the IRPs as filed.

275. The foregoing Staff recommendations apply broadly to all LSEs without discussion of the special circumstances concerning AEPCO as referenced in the Commission's prior IRP decisions. In keeping with Decision Nos. 73884 and 75068, we conclude that AEPCO should continue to participate in the IRP process by submitting whatever information, data, criteria, and studies the Cooperative has used in its 15-year planning analysis, but that AEPCO should not be subject to the additional requirements proposed by Staff, and that AEPCO's future IRPs need not be acknowledged by the Commission.

276. The Commission's Rules require a determination by the Commission whether each IRP filed by the LSEs complies with the requirements of the Rules. We find that of the 11 factors summarized in Finding of Fact 4, the APS IRP failed to comply with B, D, I, and K. In addition, Decision No. 75068 required APS to reexamine its load forecasting techniques prior to filing its IRP. As noted by Staff and the Sierra Club, APS's forecasted load growth appears too aggressive. This overstatement of growth as well as the apparent lack of compliance with Decision No. 75068 support the decision to decline to acknowledge APS's IRP. Consequently, there can be no coordinated efforts with other LSEs, because the APS IRP is based on faulty and/or unrealistic load growth. We disagree

[47] see footnote 15

with Staff's recommendation and based on the information provided by the LSEs, we find that it is in the public interest to decline acknowledgement of any of the IRPs as filed.

CONCLUSIONS OF LAW

1. Arizona Public Service Company, Tucson Electric Power Company, UNS Electric, Inc., and Arizona Electric Power Cooperative are Arizona public service corporations within the meaning of Article XV, Section 2, of the Arizona Constitution.

2. The Commission has jurisdiction over Arizona Public Service Company, Tucson Electric Power Company, UNS Electric, Inc., and Arizona Electric Power Cooperative, and over the matters raised herein.

3. The Commission, having reviewed the final 2015 and 2016 Integrated Resource Plans of Arizona Public Service Company, Tucson Electric Power Company, UNS Electric, Inc., and Arizona Electric Power Cooperative, Staff's Assessment of the 2015-2016 Integrated Resource Plans and its Recommended Opinion and Order, both dated November 1, 2017, finds that the subject Integrated Resource Plans do not meet the requirements of the Commission Resource Planning and Procurement rules.

ORDER

IT IS THEREFORE ORDERED that the Load Serving Entities, except Arizona Electric Power Cooperative, shall include in their portfolio analyses the forecasted change in costs of both established technologies and emerging technologies.

IT IS FURTHER ORDERED that the Load Serving Entities, except Arizona Electric Power Cooperative, shall include a tabular representation that provides a breakdown by capacity and energy mix contributions for each portfolio that was analyzed, similar to Table ES-2 on Page 13 of APS' 2017 IRP. The table shall include a breakdown of each specific technology type, listed under a given resource that was included in the portfolio analysis. The breakdown shall include the name of the technology (i.e. "Aeroderivative Gas Turbine" listed under "Natural Gas", "Combined Cycle" listed under "Natural Gas", "Utility Scale Solar – Thin Film Solar PV – Fixed" listed under "Renewables", "Rooftop Solar PV" listed under "Renewables", etc.), its capacity contribution to the portfolio, the cost per MW ($ Per MW) of that particular technology, and the total cost.

IT IS FURTHER ORDERED that the Load Serving Entities, except Arizona Electric Power Cooperative, shall coordinate with Staff to hold a public workshop within 60 days after filing future preliminary IRPs, for the sole purpose of discussing each portfolio that will be analyzed by the Load Serving Entities. Specifically, the modeling assumptions (i.e. reasons why certain technologies were selected and the associated costs), the modeling outputs, and modeling methodologies shall be discussed at the workshop.

IT IS FURTHER ORDERED that for all future IRPs submitted by Arizona Public Service Company, Tucson Electric Power Company, and UNS Electric, Inc., Staff shall, in addition to their existing review requirements and methods, hire one or more third-party analysts to conduct an independent review of the scenarios and portfolios presented in each IRP, and of their respective costs and benefits, and to develop and present alternative scenarios and portfolios the third-party analyst deems are not adequately represented or considered in the IRP. The hiring of a third-party analyst shall require prior Commission approval.

IT IS FURTHER ORDERED that the Load Serving Entities, except Arizona Electric Power Cooperative, shall address natural gas storage in greater detail in future IRPs, including a discussion of efforts to develop natural gas storage, the costs and benefits of natural gas storage, and risks resulting from a lack of market area natural gas storage in Arizona. In addition, natural gas pricing issues are a key driver in future resource planning decisions by Arizona utilities. Thus a very robust sensitivity analysis, considering a wide variety of natural gas price scenarios, shall be a cornerstone of utility resource planning in Arizona. Consequently, the Load Serving Entities, except Arizona Electric Cooperative, shall include a wide variety of natural gas price scenarios in future IRPs.

IT IS FURTHER ORDERED that Staff shall, within 60 days of the effective date of this Decision, open a formal rulemaking docket and, within 120 days of the effective date of this Decision, hold a first in a series of stakeholder workshops to completely revise and reform the existing Resource Planning and Procurement rules, A.A.C. Title 14, Chapter 2, Article 7, to include, but not be limited to, Staff recommendations in Finding of Fact 267 and all other necessary and prudent reformations.

IT IS FURTHER ORDERED that the following timeline is adopted for Load Serving Entities to follow in preparing and filing their next Integrated Resource Plans.

IRP Process Step	Start Date	Due Date	Responsibility
Pre-Filing Workshops (optional)	8/1/2018	1/31/2019	LSEs/ACC
LSEs File Preliminary Resource Plans	4/1/2019	4/1/2019	LSEs
Staff Reviews Preliminary Plans/Stakeholder Review	4/1/2019	6/1/2019	Staff
ACC/Staff Holds Workshop(s) on Preliminary Plans	5/1/2019	6/1/2019	LSEs/ACC/Staff
ACC Open Meeting To Review preliminary Resource Plans	7/15/2019	8/15/2019	ACC
Pre-Filing Workshop on Final Resource Plans	9/1/2019	11/30/2019	LSEs/ACC
LSE's File Final Resource Plans	4/1/2020	4/1/2020	LSEs
Stakeholder Comments Due	7/1/2020	7/1/2020	Stakeholders
LSEs' Response to Stakeholder Comments Due	7/1/2020	8/15/2020	LSEs
Staff Assessment and Proposed Order	7/1/2020	11/2/2020	Staff
ACC Holds Open Meeting Acknowledge Final Integrated Resource Plans	1/15/2021	2/15/2021	ACC

IT IS FURTHER ORDERED that the filing date set forth in A.A.C. R-14-2-703(C) that would have required Integrated Resource Plans to be filed on April 1, 2018 is waived, and is replaced with the dates included in the schedule set forth above.

IT IS FURTHER ORDERED that the deadline for stakeholder comments regarding Final Integrated Resource Plans shall be 90 days from the date said Final plans are filed in Docket Control. LSE's shall have 45 days from the deadline for stakeholder comments to file a response to any stakeholder comments filed in Docket Control.

IT IS FURTHER ORDERED that Staff shall conduct one or more EE workshops to allow stakeholders to provide input regarding the future of EE beyond the 2020 expiration date.

IT IS FURTHER ORDERED that all Load Serving Entities, except Arizona Electric Power Cooperative, shall include, in future Integrated Resource Plans, an analysis of a reasonable range of storage technologies and chemistries; and an analysis of anticipated future energy storage cost declines as further discussed in Decision No. 76295.

IT IS FURTHER ORDERED that all Load Serving Entities, except Arizona Electric Power Cooperative, shall include a storage alternative as a resource option in future Integrated Resource Plans, and shall include an analysis of storage alternatives into their respective processes when considering upgrades to transmission or distribution systems, or when considering new build or capacity upgrades for existing generation resources.

IT IS FURTHER ORDERED that Arizona Public Service Company shall prepare a report justifying its 2015 and 2016 IRP load growth projections. Said report shall also include an analysis of (A) a "no growth" scenario; and (B) a "low growth" scenario (<1-percent growth) and the resultant implications on APS's resource selections under each scenario. APS shall also include a discussion regarding how each of the required scenarios affect its Three Year Action Plan. Said report shall be filed in the instant docket within 90 days of the Commission's decision in this matter.

IT IS FURTHER ORDERED that all Load Serving Entities, except Arizona Electric Power Cooperative, shall include "no-growth" and "low-growth (<1%)" scenarios in future Integrated Resource Plans, until further order of the Commission.

IT IS FURTHER ORDERED that Arizona Public Service Company, Tucson Electric Power Company, and UNS Electric, Inc. in each of their next IRPs shall analyze, along with their preferred portfolio, at least one portfolio where the addition of fossil fuel resources is no more than twenty percent (20%) of all the resource additions. In developing each of their portfolios to satisfy this requirement, Arizona Public Service Company, Tucson Electric Power Company, and UNS Electric, Inc. shall each work in good faith with each of the stakeholders in this case that desire to continue to participate and also work in good faith with any Tribal Nations located in Arizona that desire to participate in developing the portfolio to satisfy this requirement.

IT IS FURTHER ORDERED that Arizona Public Service Company, Tucson Electric Power Company, and UNS Electric, Inc., in each of their next IRPs shall analyze, along with their preferred portfolio, at least one portfolio that includes, as a fifteen year forecast, all of the following: the lesser of 1000 MW of energy storage capacity or an amount of energy storage capacity equivalent to 20% of system demand; at least 50% of "clean energy resources," which are resources that operate with zero net emissions beyond that of steam, of which 25 MW of nameplate capacity running at no less than 60% capacity factor are renewable biomass resources; and at least 20% of Demand Side Management.

IT IS FURTHER ORDERED that a Load Serving Entity may not procure by purchase, acquisition, or construction a generating facility of natural gas energy of 150 MW of capacity or more unless all of the following conditions are met: (a) all ordering paragraphs, conditions, and additional compliance items required by this Decision have been fully satisfied, as determined by a future order of the Commission; (b) the Load Serving Entity has conducted an independent analysis comparing the present and future costs between the specific natural gas procurement and alternative energy storage options and Staff reviewed that analysis; and (c) the Load Serving Entity filed a petition under R14-2-704(E) that seeks approval for the specific procurement, and the Commission approved the petition. This ordering paragraph and the requirements it establishes shall expire automatically on January 1, 2019.

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IT IS FURTHER ORDERED that Tucson Electric Power Company shall file an update to its Three-Year Action Plan to reflect its announced intention to acquire Unit 2 of the gas-fired Gila River Power Station within 30 days of the Commission's decision in this matter.

IT IS FURTHER ORDERED that the Commission does not Acknowledge the Final Integrated Resource Plans as filed by Arizona Public Service Company, Tucson Electric Power Company, and UNS Electric, Inc.

IT IS FURTHER ORDERED that the Final Integrated Resource Plan filed by Arizona Electric Power Cooperative satisfies the requirements established in Decision Nos. 73884 and 75068.

BY THE ORDER OF THE ARIZONA CORPORATION COMMISSION

CHAIRMAN FORESE COMMISSIONER DUNN

COMMISSIONER TOBIN COMMISSIONER OLSON COMMISSIONER BURNS

IN WITNESS WHEREOF, I, TED VOGT, Executive Director of the Arizona Corporation Commission, have hereunto, set my hand and caused the official seal of this Commission to be affixed at the Capitol, in the City of Phoenix, this 29TH day of MARCH, 2018.

TED VOGT
EXECUTIVE DIRECTOR

DISSENT: ____________________

DISSENT: ____________________

EOA:ZTB:red/CHH

Resource Planning and Procurement in 2015 and 2016
Docket No. E-00000V-15-0094

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