Western Resource Advocates Stakeholder Comments on Arizona Public Service's Integrated Resource Plan

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Western Resource Advocates

WRA's Stakeholder Comments on Arizona Public Service's Integrated Resource Plan

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I. Introduction

Western Resource Advocates ("WRA") submits the following comments on the 2023 Integrated Resource Plan ("IRP") of Arizona Public Service ("APS"). WRA is a non-profit, public interest conservation organization dedicated to protecting the land, air, and water of the West. WRA develops and implements policies to reduce the environmental impacts of the electric power industry in the region. WRA participated in APS's Resource Planning Advisory Council ("RPAC") and Modeling Committee. During this process WRA has worked closely with GridLab and an independent modeler, Energy Strategies, to examine APS's modeling and future resource opportunities. WRA has substantial experience in the IRP process after participating in years of IRPs both in Arizona and in other Western states. WRA supports the acknowledgement of APS's IRP but recommends that in its May 31, 2024, Response to Stakeholder Comments APS address certain plan deficiencies.

II. Background

A. Integrated Resource Planning

An Integrated Resource Plan is a tool for utilities and regulators to determine which mix of supply-side and demand-side resources will meet energy demand while keeping costs low, mitigating risk, and achieving policy goals.[1] The IRP process requires utilities to use analytical tools that can fairly evaluate and compare the costs and benefits of different kinds of resources.[2] This analysis goes beyond considering supply-side options.[3] Integrated resource planning presents an opportunity for utilities in Arizona to demonstrate to the Arizona Corporation Commission ("Commission") that Arizona's families and businesses will have affordable, reliable and sustainable energy.

IRPs are most effective when they are comprehensive, aligned, trusted, and impactful.

- **Comprehensive:** An IRP should accurately model the full suite of costs, system impacts, capabilities, and value of resources, and should consider these factors across transmission and distribution systems.[4]
- **Aligned:** To be effective, an IRP should meet traditional planning requirements including affordability, safety, and reliability.[5]

[1] Mark Dyson et al., *Reimagining Resource Planning*, ROCKY MOUNTAIN INSTITUTE, 7 (2023), https://rmi.org/insight/reimagining-resource-planning.
[2] David Millar et al., *Redacted Revised Report Arizona Utility Integrated Resource Plan Review*, ASCEND ANALYTICS, 25 (2021), https://docket.images.azcc.gov/E000015107.pdf?i=1706030435502.
[3] *Id.*
[4] Dyson, *supra* note 1, at 8.
[5] *Id.*

- **Trusted:** The resource planning process works best when it is transparent, well vetted, and includes robust and diverse stakeholder input.[6]
- **Impactful:** An IRP should elicit Commission review and approvals of specific resource-related decisions based on competitive solicitations that are informed by the approved IRP modeling. All subsequent resource-related decisions should be consistent with the prior approved IRP.[7]

Without these qualities the accuracy, credibility, and effectiveness of any IRP may be eroded, which in turn can cause unanticipated costs to rate payers, imprudent investments, and public policy failures.[8]

Comprehensive utility planning – like the IRP process – is more important than ever and provides utilities an opportunity to cost-effectively navigate the constantly evolving energy landscape in Arizona. This is especially salient for APS, which faces significant projected growth in population and load, the retirement or exit from two coal power plants, as well as the increasing incidence of extreme weather.[9] To address and meet these opportunities APS must account for cost-competitive renewable energy and storage resources, historic fuel price volatility, and global supply chain uncertainties. It must also incorporate statutory considerations surrounding climate change and carbon emissions in its IRP. Fortunately, utilities in Arizona have a diverse ecosystem of informed stakeholder organizations, like WRA, that are able to provide feedback and recommendations, and a Commission that will keep APS accountable to administrative requirements and Arizona's ratepayers.

This proceeding represents an important opportunity to shape Arizona's energy future.

B. Integrated Resource Planning in Arizona

The Commission adopted its first Resource Planning and Procurement Rules in 1989, and the rules were subsequently updated in 2010.[10] Arizona Administrative Code Title 14, Chapter 2, Article 7 states in part that utilities must: forecast 15 years in advance; file an IRP every even number year; disclose potential renewable resources, energy efficiency considerations and environmental concerns; and requires opportunities for public input.

[6] *Id.*
[7] For example, in some states, like Colorado, approval of a resource from a competitive solicitation linked to a resource plan creates a presumption of prudence, reducing litigation at the Certificate of Public Convenience and Necessity (CPCN) stage.
[8] *Id.* at 9.
[9] Todd P Komaromy, *APS 2023 Integrated Resource Plan*, 5 (2023), https://docket.images.azcc.gov/E000031965.pdf?i=1706042902736.
[10] Docket No. RE-00000A-09-0249, Decision No. 71722, https://docket.images.azcc.gov/0000112475.pdf?i=1706042473298; Arizona Administrative Code Title 14, Chapter 2, Article 7, Resource Planning.

Following the review of IRPs filed by utilities, the Commission is required to file an order that acknowledges the IRPs, modifies the IRPs, or states the reason for denying them.[11]

In deciding whether an IRP should be acknowledged, the Commissioners are directed by A.A.C. R14-2-704(B) to consider the following factors:

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

APS's 2021 IRP was acknowledged by the Commission in Decision No. 78499. In that decision, the Commission also established several requirements for future resource plans,[12] These requirements include:

1. **Incorporating "the extension of key tax credits" and a "plan to run one of the Four Corners units seasonally."[13]**
2. **Analyzing a minimum of 10 resource portfolios "that are designed to evaluate the range of resource procurement actions, and their respective costs and benefits,**

[11] A.A.C. R14-2-704(B).
[12] Docket E-00000V-19-0034, https://edocket.azcc.gov/search/docket-search/item-detail/22167.
[13] Decision No. 78499, at 17.

that can be taken to achieve the emissions reduction goals specified" in APS's 2020 IRP.[14] The Commission went on to identify specific portfolios it wanted to be presented, such as a portfolio that removes restrictions on energy efficiency, a portfolio that removes modeling restrictions on the economic cycling and economic retirement of coal units, and a portfolio that eliminates must-run designations.[15]

3. **Providing "information on how each portfolio performs in terms of total cumulative emissions reductions in addition to annual emissions numbers."**[16]

4. **Presenting "robust retirement analyses[,] including specific estimated retirement dates for each resource."**[17] More specifically, the Commission directed APS to file "a comprehensive early retirement analysis for [APS's] stake in Four Corners Power Plant."[18] This analysis must include an evaluation of the economic costs and benefits to customers from the retirement, and possible necessary replacement of energy and capacity, and impacts to electric reliability.[19] The Commission directed APS to evaluate 2024, 2025, 2026, 2027, 2028, 2029, 2030, and 2031 retirement dates.[20]

5. **Filing a Market Report on the status of the utility's engagement in regional market forums.**[21] The Commission requires this Market Report to include "participation and intentions for further participation including cost savings and other benefits, barriers and concerns related to governance of western market proposals, transmission planning, coordination, open-access tariff consolidation, cost allocation and utilization arrangements, planning for resource adequacy and shall identify information the Commission needs to aide in future enabling decision-making."[22]

6. **Providing modeling software licenses to up to 12 RPAC members, thereby enabling those organizations to perform their own modeling runs.**[23] Through this requirement, the Commission recognized the broader process benefits when stakeholders have the tools to provide alternative perspectives on how to meet reliability, emission reductions, and affordability objectives. This improved transparency and reduction in information asymmetry can assist regulators and stakeholders in making fully informed resource decisions. Stakeholder portfolios can

[14] *Id.* at 13.
[15] *Id.* at 14, 16.
[16] *Id.* at 17.
[17] *Id.* at 12.
[18] *Id.*
[19] *Id.* at 11-12.
[20] *Id.* at 12.
[21] *Id.* at 11-12.
[22] *Id.*
[23] *Id.* at 14.

provide options not previously considered by utilities and can challenge the assumptions inherent in a utility's portfolios.

Commission Decision No. 78499, which was approved by Commissioner Lea Marquez Peterson, Commissioner Anna Tovar, and Chairperson Jim O'Connor, established a more robust IRP procedure for utilities to follow in Arizona. The Commission should build upon the improvements established in this decision, and further refine the IRP process using lessons learned from this IRP cycle. By doing this, the Commission can help to ensure that IRPs in Arizona are comprehensive, aligned, trusted, and impactful. This, in turn, will directly benefit utilities, stakeholders and, most importantly, Arizona's ratepayers.

C. APS's Stakeholder Process and the Resource Planning Advisory Committee

The Commission should recognize the importance of the stakeholders in the IRP process and continue to require this process in future decisions. APS has hosted more than 20 engagements since 2021 with its RPAC.[24] The utility IRP process also benefits from RPAC input in the development of resource procurement strategy and modeling assumptions. In accordance with Decision No. 78499, APS provided access to its data and software tools to stakeholders so that those organizations, which included two environmental groups and a trade association, could run their own portfolios.[25] WRA and APS attest that this improved stakeholder engagement process has delivered meaningful benefits to participants and provided "a shared value solution."[26]

The Commission should again require that APS engage in a robust stakeholder process, including a requirement to negotiate a project-based licensing fee to allow access to data and software tools for stakeholders who opt to participate. This collaborative process improved APS's analysis and improved the transparency of this IRP. Commission Decision No. 78499[27] has also enabled stakeholders to provide valuable information to Staff and the Commission, which is demonstrated by this report. However, given that this is the first IRP cycle using this RPAC process with shared modeling resources, WRA has recommendations for improvement.

[24] Komaromy, *supra* note 9, at 6.
[25] *Id.* at 13.
[26] *Id.*
[27] Decision No. 78499, at 12.

III. Comments and Recommendations

APS filed its Integrated Resource Plan on November 1, 2023. The IRP details how APS plans to navigate the next 15 years and addresses some of the opportunities and challenges it will face during that period.[28] APS states it is "rapidly increasing the amount of cost-effective clean energy on [its] system," and it has a goal of 65% clean energy by 2030.[29] Despite this, APS has only committed to reduce its carbon dioxide pollution 60% by 2030, relative to a 2005 baseline.[30]

APS's reference case incorporates a forecast of technology costs, load, and commodity prices for the next 15 years.[31] The reference case includes a diverse portfolio of methane gas, microgrids, solar, wind, energy storage, transmission facilities and demand-side programs. APS's reference case adds 14,000 megawatts ("MW") of supply-side resources by 2038, and nearly 5,000 MW of demand-side resources.[32] APS's reference case also assumes that APS will exit Four Corners Generating Station in 2031 and add 1 gigawatt ("GW") of new methane gas combustion turbine capacity in that year.[33]

APS's reference case provides the basis for WRA's analysis and serves as a useful point of comparison for outside parties to develop alternative portfolios; however, it is not APS's preferred portfolio as described in the IRP. Using APS's reference case, WRA and Energy Strategies developed alternative portfolios to offer additional points of comparison relative to APS's IRP. These alternative portfolios were designed to explore how small changes to key input assumptions or resource decisions might affect the overall portfolio, as well as key metrics including portfolio cost, emissions, resource retirements, reliability, and more.

WRA recommends the Commission acknowledge APS's IRP. However, there are significant areas for improvement in APS's plan. In order to ensure APS's IRP and subsequent resource acquisitions prudently meet the needs of Arizonans, WRA recommends certain amendments to its plan, which should be submitted as part of APS's Response to Stakeholder Comments, which is due May 31, 2024.

First, in order to correctly model its generation resource needs in the future, APS should refine its load forecast. Second, to reduce costs for customers, APS should select the Four Corners Coal Exit 2028 Case as its preferred portfolio. Third, APS should present a version of its preferred portfolio that includes assumptions for the operation of a day-ahead

[28] Komaromy, *supra* note 9, at 5.
[29] *Id.* at 8.
[30] *Id.* at 84.
[31] *Id.* at 9.
[32] *Id.*
[33] *Id.* at 231, Attachment F.1(A)(1).

market, and a modified version of the Four Corners Coal Exit 2028 portfolio that also incorporates assumptions for the operation of a day-ahead market. In its May Response to Stakeholder Comments, APS should also disclose the steps it plans to take to move forward with regional market participation. Fourth, APS should commit to accelerate its procurement of "no-regrets" wind, solar, storage, energy efficiency, and transmission resources.

In addition, WRA provides suggestions for the Commission as it looks forward to future IRP cycles. First, the Commission should continue its direction to APS to engage in a robust stakeholder process but provide additional specificity and direction to ensure that process is impactful and meaningful. Second, the Commission should direct APS to conduct a day-ahead market entry impact assessment to inform its next IRP cycle. Third, the Commission should move away from concurrent IRP filings for all regulated utilities, in order to allow a more thorough evaluation of each utility's proposed plan.

A. Suggested Amendments to APS's Plan

In evaluating the reference case, Energy Strategies discovered reporting issues that created difficulties in its evaluation of IRP portfolio costs. In consultation with APS, the utility confirmed to WRA and Energy Strategies that it did not include new capacity expansion resource costs in the output portfolio produced by the Aurora model. In other words, APS only considered the cost of the existing generation fleet when running the Aurora model, and then calculated the revenue requirement of the entire portfolio in an undisclosed process outside of the model. Due to APS's failure to include new capacity expansion resources in the reference case's cost outputs, it was not possible to fully and accurately evaluate the APS modeled portfolios relative to the alternative portfolios developed by Energy Strategies. While there is some discrepancy in the reported portfolio costs of the alternative portfolios relative to the IRP reference, the alternative portfolios still provide valuable points of comparison to understand changes in generation, emissions, and capacity over time.

In order to ensure APS's IRP is meeting the needs of Arizonans, WRA recommends certain amendments to APS's plan, which should be submitted as part of APS's May Response to Stakeholder Comments.

1. APS Should Refine and Update its Load Growth Assumptions

A load forecast is a key input assumption for IRP modeling and is a critical factor driving resource acquisitions selected in the modeling results. Utilities should use reasonable and reliable load forecast assumptions for their base case modeling and test the robustness of portfolio alternatives with high and low load growth sensitivities.

APS developed load forecasts for the near term covering the 15-year Action Plan period and representing the longer term for the full planning period of 2023-2038. It is apparent in Figure 2.2 of the IRP that APS projects a substantial increase in load growth starting immediately and following a rapid load growth trend continuing through the planning period.[34] This load growth trend, which APS relies on as its base case assumption for its IRP modeling, is substantially driven by APS's predicted growth of data centers and industrial loads.

The Commission should ensure that the utility's base case load forecast is not based on speculative assumptions and reasonably captures likely load growth. As shown in Figure 1 below, APS anticipates that its residential and commercial customers represent a small portion of future load growth.[35] Despite the rapid population growth in APS's territory, the utility's energy efficiency programs have helped to temper the energy consumption growth trends for residential and commercial customers.[36] Rather, the utility anticipates the greatest share of future load growth to come from data centers and large industrial manufacturing. WRA is concerned that the forecast load growth from the data center and manufacturing sectors is speculative, as the projected data center growth assumes investment decisions of private corporate entities, and the manufacturing load forecast includes assumptions for hydrogen production.[37] In particular, the hydrogen production sector is extremely nascent.

COMPONENT	GWH
New Data Centers	12,997
Large Industrial & Manufacturing	5,843
Electric Vehicles	3,406
C&I	785
Residential	657
TOTAL GROWTH	**23,689**

Figure 1: Sources of Energy Growth 2023-2038 – APS IRP Table 2-1

Considering the uncertainty and enormity of these data center and industrial load growth projections, WRA recommends APS refine and revise its base case load growth forecasts to reduce speculative assumptions and shift such uncertain load growth to the High Load sensitivity analysis. While electric vehicle load is also a significant component of projected electricity needs, forecast EV load is lower than for the data center and manufacturing sectors, and utilities are already implementing programs to manage EV loads more flexibly than may be anticipated for data centers and manufacturing.

The Commission should also ensure that cost allocation methodologies in future rate cases fairly allocate costs for new generation across customer types. Fair allocation methodologies avoid burdening residential and commercial customers with excessive costs of meeting the larger electric load growth trends of data centers and industrial customers, especially if the methodology assigns costs to customer classes based on their share of load during just four peak hours of the year. Where this occurs, costs tend to shift to residential customers as the peak load hours shift later in the day.

[34] *Id.* at 19, Figure 2-2.
[35] *Id.* at 19, Table 2-1.
[36] *Id.* at 26.
[37] *Id.* at 20.

2. APS Should Select the Lower-Cost Four Corners Coal Exit 2028 Case as its Preferred Portfolio

In order to reduce costs for customers, APS should select the Four Corners Coal Exit 2028 Case as its preferred portfolio in its May Response to Stakeholder Comments, and the Commission should acknowledge APS's IRP with this change. APS's own modeling shows substantial cost savings from retiring Four Corners in 2028, which would save its customers $139 million compared to the reference case (Portfolio 01).[38] APS modeling results further show that delaying the Four Corners retirement to 2029 or 2030 results in additional cost with each year of delay, costing an additional $48 million in 2029 and another $82 million if retirement is delayed until 2030, as shown in Figure 2 below.[39]

In WRA's modeling, the Early Four Corners Retirement portfolio prepared by WRA's independent modeler further validates APS's own finding of the cost savings that arise from retiring Four Corners in 2028. The Four Corners Coal Exit 2028 alternative portfolio is one of the lowest cost alternatives developed by APS and is also cheaper than five of the six alternatives modeled by WRA's independent modeler.[40] The early retirement of Four Corners in 2028 is the most prudent and cost-effective resource portfolio decision. WRA's alternative portfolios demonstrate shifting investment towards wind, solar and storage will *decrease* customer costs.

SCENARIO	PVRR ($ MILLIONS)	PVRR RELATIVE TO REFERENCE CASE ($ MILLIONS)
Reference	$37,722	-
Four Corners Coal Exit 2027	$37,748	+$26
Four Corners Coal Exit 2028	$37,583	-$139
Four Corners Coal Exit 2029	$37,631	-$91
Four Corners Coal Exit 2030	$37,665	-$57

Figure 2: Four Corners Revenue Requirement Comparison – APS IRP Table 5-3.

Early retirement of these generation units and avoiding the substantial operation and maintenance costs associated with coal plants will save ratepayers more than the lifetime costs of these new renewable resources.

[38] *Id.* at 71.
[39] *Id.* at 75, Table 5-3. The lost savings from each year of delay is calculated by subtracting the savings in that year from the $139 million savings if retirement were to occur in 2028.
[40] Appendix 2, at 20.

WRA applauds APS's acknowledgement of the need to test the competitive market for low-cost resources to re-assess the Four Corners retirement date.[41] However, WRA questions APS's approach to incorporating the Four Corners coal contract cost assumptions in the portfolio modeling.[42] Any fixed coal contract costs that remain through 2031 are sunk costs — they eventually will be incurred regardless of the operation or retirement of the unit. APS's coal contract cost assumptions applied to its modeling create an illusion of cost savings for its preferred portfolio, which has a Four Corners retirement date of 2031. The results of the other retirement portfolios clearly show $139 million in savings for retirement in 2028, with lost savings for each subsequent year of delay. In APS's May Response to Stakeholder Comments, it should update its modeling to remove the fixed coal contract costs and instead treat those costs as sunk costs outside of the model.

APS asserts it is concerned reliability will be impacted if Four Corners is retired in 2028. But these concerns are rebutted by APS's own resource adequacy studies.[43] APS states that all portfolios modeled in its IRP "are designed to meet or exceed APS's loss of load expected ("LOLE") standard of 0.1 days per year." LOLE refers to analysis of loss of load expected, using a standard equivalent to one day in ten years.[44] In other words, APS's own reliability modeling demonstrates a portfolio that includes a 2028 Four Corners retirement date meets or exceeds the reliability standard established by APS. In APS's discussion on reliability, the utility argues Four Corners would need to be replaced with "large amounts of a nascent technology."[45] From the utility's filing, it is unclear which specific technologies APS is dismissing as "nascent." Notably, the renewable resources required to replace this capacity cannot be reasonably characterized as "nascent" – the Energy Information Administration's Short-Term Energy Outlook ("STEO") predicts that in 2024 the United States will install 36 GW of solar and install another 43 GW in 2025.[46] These are mature, deployable technologies. The STEO goes on to predict "electricity generation from coal will decline by 9% in 2024 and by 10% in 2025, due to a combination of higher costs compared with renewables," further demonstrating clean energy's cost competitiveness with coal generation. Put quite simply, coal generation is expensive, and the modeling demonstrates cheaper alternatives are available using mature technologies. The path forward is investing in "no-regrets" resources like wind, solar, storage, energy efficiency, and transmission capacity.

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[41] Komaromy, *supra* note 9, at 76, stating "The Company will continue to evaluate the market drivers, infrastructure development opportunities, and resource costs to assess the viability of an earlier exit if there is a benefit for customers while maintaining reliability."
[42] *Id.* at 69.
[43] *Id.* at 9.
[44] *Id.* at 71.
[45] *Id.* at 70.
[46] *Short Term Energy Outlook*, U.S. ENERGY INFORMATION ADMINISTRATION (Jan. 2024), https://www.eia.gov/outlooks/steo/.

WRA's No Fossil and Early Four Corners Retirement alternative portfolios both demonstrate significant benefits from accelerating retirement of the Four Corners facility. WRA's No Fossil alternative portfolio restricts capacity expansion to non-emitting resources only, meaning the model cannot build new fossil fuel plants. This portfolio provides a representation of how Four Corners could be retired in 2028 without adding new fossil fuel resources. Even without a stringent carbon emissions constraint, the No Fossil portfolio still results in significantly higher carbon emissions reductions relative to the IRP reference case (69% vs. 51% CO_2 emissions reductions by 2050 vs. 2005).[47] This portfolio accelerates the deployment of non-emitting resources, including over 4,000 MW of solar and wind each, as well as over 6,000 MW of new battery storage through the end of the study period. By 2039, the No Fossil portfolio reduces CO_2 emissions by 69%.

WRA's Early Four Corners Retirement alternative portfolio is one of the lowest cost alternatives developed. This portfolio is cheaper than five of the six alternatives modeled, suggesting that an early retirement of Four Corners is likely the most prudent and cost-effective resource portfolio decision. In this portfolio, retiring coal capacity is replaced with a combination of new methane gas, renewable, and storage resources, similar to the results of APS's modeling of a 2028 Four Corners retirement. The model output is an estimate based on the assumptions provided by APS, including generic replacement resource costs and operational parameters. Actual project bids obtained through a competitive solicitation process will inform the replacement acquisition decisions. The early retirement of Four Corners remains the least-cost method of reducing emissions in the APS portfolio, and in fact is one of the most cost-effective resource decisions available to the Company. Despite the necessity to deploy new resources to meet the capacity shortfall, including new wind, solar, and battery storage, retiring Four Corners is the most prudent resource decision for ratepayers.

3. APS Should Incorporate Market Assumptions in its Preferred Portfolio and as a Baseline Assumption for All Portfolios Going Forward

It is vital that APS incorporate assumptions reflecting anticipated participation in a regional energy market in its IRP portfolio analysis, to examine and assess the impact on its resource mix and system operations. Despite APS's extensive involvement in day-ahead market development, the IRP contains insufficient examination of market participation impacts on its portfolio selection. APS is actively exploring joining a day-ahead market, which should provide sufficient clarity to inform modeling assumptions to understand potential market effects for APS's system and should inform the utility's resource acquisition action plan. APS is a member of the Western Energy Imbalance Market ("WEIM") and has been an active player in various efforts in the West to develop a day-ahead electricity market, both with the California Independent System Operator's Extended Day-Ahead Market ("CAISO EDAM") and the

[47] Appendix 2, at 17.

Southwest Power Pool's Markets+ initiative. Additionally, APS was a founding member of the Western Markets Exploratory Group ("WMEG") and is involved with the Western Resource Adequacy Program ("WRAP"), which is standardizing reliability planning standards to facilitate future market implementation.

It is likely APS will join a day-ahead market by 2025-2026, making this IRP cycle an important and highly valuable opportunity to model and evaluate how market participation would impact APS's resource mix and the dispatch of fossil-fueled versus non-emitting energy resources on the APS system. This type of forward-looking evaluation is the purpose of IRP proceedings and helps the utility, stakeholders, and the Commission plan for the future. Arizona typically uses a three-year IRP cycle; if APS elects to join a day-ahead market before the next IRP cycle, there will be no opportunity to assess these system impacts in advance.

Although APS discusses regional electricity markets in its IRP filing, it does not include electricity market considerations in any of the modeled portfolios. Notably, WRA's Market Expansion portfolio,[48] developed by Energy Strategies as an alternative portfolio to represent the effects of APS joining a regional electricity market, is the least-cost portfolio modeled, illustrating the value of assessing market impacts in this IRP. This result is presented in the Energy Strategies' Aurora Model Review and Alternative Futures, showing that a total estimated cost for the Market Expansion portfolio is $1.83 billion less than the IRP Reference portfolio (Portfolio 1) over the planning period.[49] WRA's Market Expansion alternative portfolio shows the profound economic value of energy markets and the potential to unlock substantial savings for ratepayers.

APS commissioned a Resource Adequacy study by the consulting firm Astrape to inform its planning reserve margin analysis. The Astrape study observes that participation in a regional market will impact the utility's resource utilization and suggests that even with conservative assumptions, such as assuming neighboring utilities under-perform on resource adequacy requirements by 3%, APS could see benefits of a reduced capacity need on its own system. Specifically, Astrape concluded that its Expanded Market Access scenario shows the potential to reduce the utility's planning reserve margin by 3.2% in comparison to the reference case.[50] WRA's Market Expansion portfolio applies different assumptions, assuming doubling of the energy import limit from 700 MW to 1400 MW. WRA's Market Expansion portfolio results in fairly consistent capacity additions in comparison to the APS reference case, but less need for methane gas fuel combustion. These two approaches to modeling the effects of regional market participation both show substantial potential benefits. Therefore, APS should include market participation assumptions in its May Response to Stakeholder Comments to assess generally how market participation could impact its system and ratepayers.

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[48] Appendix 1, at 2.
[49] Appendix 2, at 20.
[50] Appendix 2, at 8.

Additionally, APS should describe the steps it plans to take to move towards market participation.

4. APS Should Accelerate its Procurement of "No-Regrets" Wind, Solar, Storage, and Efficiency Resources

APS's near-term acquisition of wind, solar, and storage resources will be investments with no regrets. APS's modeling results select substantial amounts of these resources for all portfolios. APS discusses this in its Key Learnings From Portfolio Analysis section saying, "Increasing reliance on renewable is least cost for customers, particularly upon the retirement of Four Corners," and goes on to say that in the Technology Neutral scenario, which has no clean energy or renewable requirements imposed, the model still builds more than 10,000 MW of new wind and solar.[51] Similarly, across all the alternative portfolios modeled by WRA's independent modeler, one consistent outcome is a dramatic increase in new wind, solar, battery storage, and demand-side resources to meet APS's load.[52] This means that a portfolio including these resources is robust across scenario assumptions. These are also low-cost alternatives to continued investment in emitting resources. Solar remains a key resource across all portfolios, given the high quality and low cost of the resource in the region. Across all the alternative portfolios produced for WRA by Energy Strategies, the model builds 2,000-4,000 MW of new solar resources over the study period. As saturation of solar increases, the system recognizes a need for complementary resources. Wind, battery storage, and demand-side management bolster the alternative portfolios by providing complementary energy and capacity. All the alternative portfolios explored by WRA add substantial new amounts of wind generation – on average approximately 3,500 MW of new wind over the study period. In the No Fossil and Carbon Reduction alternative portfolios, the wind additions are more pronounced.

The story is the same for battery storage, which serves as a critical energy and capacity resource as the APS resource mix changes over time. All alternative portfolios modeled by WRA add large amounts of new energy storage resources, ranging between 2,000-4,000 MW over the study period, depending on the portfolio. The No Fossil and Carbon Reduction alternative portfolio further expand acquisitions, adding up to 6,000 MW of new battery storage. Additionally, in all of WRA's alternative portfolios except the IRP Reference and Market Expansion portfolios, demand-side management ("DSM") plays an important role as a capacity resource. A diverse combination of solar, wind, and DSM are foundational resources for APS in all portfolios modeled.

When looking at generation by resource type, the trends are similar across all the alternative portfolios WRA modelled: gas generation falls as renewable and storage resources ramp up. While new gas capacity is added in the Early Four Corners Retirement alternative portfolio to compensate for less coal capacity, gas as a share of total energy generation is still

[51] Komaromy, *supra* note 9, 80.
[52] Appendix 2, at 6, 16.

lower in 2039 than in the IRP reference. The low-carbon portfolios see a greater decrease in gas generation, resulting in annual gas generation that is 7-14% lower in 2039 relative to the IRP reference. Solar generation remains consistent across all portfolios as solar capacity reaches high saturation levels, given the assumptions built into the model for storage performance. To add additional energy, wind generation ramps up to meet the needs of the system, particularly in the low-carbon cases. In these portfolios, wind generation is 5-11% higher than the IRP reference. Imports remain the same across all portfolios except the Market Expansion portfolio, which evaluates the impacts of APS doubling market imports. As a result of increased imports, reliance on DSM falls in this portfolio, as the system requires less capacity to meet annual load.

In addition to renewable and storage resources in the APS preferred portfolio, the reference and Four Corners Coal Exit 2028 portfolios selected large amounts of methane gas generation throughout the planning period, with most of those resources selected in later years beginning in 2029 or 2031. While gas combustion turbines provide a flexible resource to integrate variable renewable generation, storage can also provide that service, among a broad suite of other services. Storage technologies are improving, and various options for long-duration storage are on the horizon. However, investing in methane gas combined-cycle units is not recommended and should be carefully compared to alternatives, as that technology choice would expose ratepayers to significant fuel price volatility risk – a risk element that is not represented in APS's modeling. Due to their higher capacity factor operations in comparison to combustion turbines, these resources would require significantly more fuel purchases, such as are already causing spikes in customer bills. Furthermore, combined-cycle units that are designed today to operate on a hydrogen fuel mix of 30% will not be suitable or cost effective to convert to 100% hydrogen capability. Moreover, we do not yet have adequate forecasts of future fuel prices for emissions-free green hydrogen fuel and pipeline investment costs to support delivery of hydrogen fuel to generators. Therefore, the decision to invest in additional methane gas capacity should be carefully considered only after taking action to develop a no-regrets portfolio of renewable and storage resources.

In APS's preferred portfolio the utility allowed the model to select a large amount of microgrids. While WRA supports microgrids as a technology capable of enhancing grid reliability and affordability, under these specific circumstances WRA finds APS's modelling assumptions troubling. APS is using microgrids to represent anticipated growth of large commercial and industrial customer emergency backup generation, which may rely on speculative assumptions of customer investment[53] and appears to come exclusively from highly polluting on-site diesel generators. Currently, APS has just 42 MW of microgrid capacity on its system, and the ability to increase that capacity to 544 MW by 2026[54] is uncertain. While these generators are typically procured and owned by customers — creating a reduction in

[53] Komaromy, *supra* note 9, at 41-42, discussing generally customer programs to encourage microgrids.
[54] *Id.* at 231, Attachment F.1(A)(1). The same capacity acquisitions for microgrids persist for all scenarios.

total system costs for APS — diesel is expensive and can cause substantial emissions. There is limited description in its IRP on how the investment and operating costs were calculated, who bears the costs and what costs will be charged to customers, or the risks to ratepayers. This is an area that warrants further examination by the Commission.

Across all alternative portfolios modelled by WRA there is a clear theme: early action on clean resource deployment is the low-cost strategy APS should implement. Over the first 10 years of the study period (2025-2034), all alternative portfolios remain at or near cost parity as new resources are deployed, Four Corners is retired, and the system expands to meet new load requirements. In other words, the least-cost resource decisions for the next 10 years appear consistent across all alternative portfolios modeled; the future is new wind, solar, battery storage, and DSM investments.

B. Recommendations for Future IRP Cycles

1. The Commission Should Establish Specific and Clear Deadlines by Which Utilities are Required to Provide Data and Licensing to Stakeholders

Commission Decision No. 78499 was innovative in its approach to the IRP stakeholder process, but the Commission should refine that approach in its next decision to prevent unnecessary delays and to ensure the full utilization of the modeling process when stakeholders are involved.

WRA participated in APS's Modeling Committee but faced some difficulties in fully utilizing the licensing that it was provided, due to the timeline of APS's IRP process. APS sent out its nondisclosure agreement on February 2, 2023. Its first model was sent to WRA on June 26, 2023, followed shortly by the Gurobi Optimization License from Energy Exemplar that is needed to run the Aurora models used by APS for its IRP. WRA received several updates from APS throughout the process – model 2 and model 3 on August 11, 2023, and APS's final model on September 26, 2023. This left a considerably short timeframe for WRA and its consultants, GridLab and Energy Strategies, to fully utilize its licensing agreement. Utilities can spend years developing and analyzing the data used for their IRPs. Stakeholders need adequate timeframes to be able to access, digest, and respond to this data. This IRP's timeline of events demonstrates that while the RPAC process was demonstratively helpful to utilities, stakeholders and regulating entities, it has room for improvement. There were understandable issues and unforeseen delays in this process because it was the first time that APS and stakeholders were required to share information in this way. WRA acknowledges that APS acted in good faith and was responsive to communications from stakeholders. Now that APS and stakeholders have been through this process, hopefully future IRP cycles will go more smoothly.

In its next decision the Commission should establish specific and clear deadlines by which utilities are required to provide modeling software licenses and when utilities are required to share the data necessary to actually utilize shared modeling software. Specifically, utilities should provide licensing agreements and the training necessary to use the modeling software to stakeholder groups at least six months in advance of the deadline to submit IRPs. APS should also provide a preliminary dataset to stakeholders so those stakeholders can begin to utilize licenses which will, in turn, empower a more robust dialogue between the utility and stakeholders. The Commission should also require that APS provide all finalized modeling data three months before the IRP filing deadline. APS should ensure that stakeholders will be able to fully utilize the software license, which requires having the license itself, the solver, and data needed to utilize it well in advance of the IRP filing deadline.

2. The Commission Should Direct APS to Conduct a Day-Ahead Market Entry Impact Assessment to Inform its Next IRP Cycle

APS is actively exploring joining a day-ahead market, which should provide clarity on the two likely market offerings for day-ahead energy services. A well-designed day-ahead market should facilitate greater predictability and transparency of least-cost resource selection and dispatch, which is certain to impact APS's system and should inform the utility's resource acquisition action plan. It is widely recognized that participation in a broader market can improve reliability and decrease costs for consumers.

In addition to the inclusion of regional market assumptions in IRP portfolios that WRA recommends in APS's May Response filing, it will be useful to have a more robust, detailed study of regional market participation. This study may be conducted between IRP filings, to inform the next IRP cycle. APS states, "It is important for APS and others in the Western U.S. region to have multiple options when it comes to markets as many factors impact the long-term outcomes for customers."[55] However, APS also observes, "The selection of one of these day-ahead options would also require participation in that same market's real-time market."[56] WRA notes that if APS joins the SPP Markets+ day-ahead market, they must exit participation in Western Energy Imbalance Market, even though APS has already calculated $375 million in savings to its customers thanks to its participation in the Western Energy Imbalance Market.[57] WRA proposes APS perform a day-ahead market entry impact assessment that would provide a clearer analysis of the likely benefit-cost impacts of market entry with the best possible knowledge of evolving market footprints by Spring 2024. This effort can be undertaken immediately and need not be due to evolving market footprints; APS is actively evaluating its market entry today, within those same "evolving" market conditions.

The recently completed Western Markets Exploratory Group study is not a substitute for this type of analysis. The WMEG study is an insufficient basis upon which to base a prudent,

[55] *Id.* at 15.
[56] *Id.*
[57] *Id.* at 14.

just, and reasonable decision about market participation. This is due, in part, to three notable limitations of the WMEG study:

a. **Insufficient cost/benefit analysis.** While the WMEG study is characterized as a "Cost Benefit Study," in reality, the study is primarily focused on the quantification of one category of benefits (i.e., net production cost) and is not a complete cost-benefit analysis. Critically, the WMEG study fails to account for a key category of market participation costs: the expenses utilities must pay for day-ahead market implementation and operation. The study doesn't contemplate other potential market benefits (i.e., curtailment reductions, transmission benefits) and instead relies only on "net variable operational costs."

b. **Treatment of "wheeling revenue."** The WMEG study misinterprets "wheeling revenue" as the assumptions used to calculate it are problematic and inconsistent with the proposed market design incentives to incentivize long-term transmission service. Wheeling revenue losses will be marginal in the long run and not well documented.

c. **Insufficient seams analysis.** The WMEG study is overly optimistic about the seams issues that would arise from market-to-market interaction. This is an issue that will have significant impacts on both APS system operations and ratepayers.

Given this context about the WMEG study, WRA suggests the Commission utilize this opportunity to direct APS to conduct a stand-alone study in 2024 to inform the utility's next IRP cycle. WRA recommends that APS conduct a holistic "net benefit" study that includes assumed or likely SPP Markets+ and CAISO EDAM market footprints, similar to the approach that was taken in the WMEG study. Further, there is more clarity about future market footprints today than there was when the WMEG study was conducted. This assessment should include an analysis of:

a. Net production cost impact of entry into each potential market, including an evaluation of energy prices, resource selection, curtailment (or reductions) of clean energy resources, capacity requirements, transmission benefits arising from the deployment of all APS transmission assets under a "flow based" paradigm over status quo, and changes to planning reserve margin levels due to the WRAP requirement for resource sufficiency needs. This net production cost impact analysis should also factor in the "opportunity costs" of APS leaving the Western Energy Imbalance Market if it were to join SPP Markets+.

b. Likely "operational and implementation" costs APS would incur as part of the first three years of startup and operations.

c. Identification of potential seams and related economic impacts (qualitative and quantitative) due to the need for inter-operability agreements on reliability, economic coordination, and transmission access. This type of analysis is necessary because the current market designs do not have any guaranteed ability for economic exchanges to take place between the two day-ahead energy markets.

This type of study would be valuable to the Commission, Staff, APS ratepayers, and large energy customers, allowing a more informed assessment of multiple market participation pathways.

3. The Commission Should Reform the IRP Process by Staggering the Years in which Resource Planning Occurs for Different Utilities

The Commission should stagger the IRP process for different utilities in Arizona. Integrated resource planning in Arizona is a process that spans the course of two years and includes multiple utilities undergoing similar processes but facing unique challenges, opportunities, and circumstances. Staggering the utility IRP deadlines provides more equitable opportunities for customers to participate in the process and enables thorough review by stakeholders and Commission Staff.

Requiring concurrent deadlines for all Arizona regulated utilities, despite their differing circumstances, can unnecessarily complicate an already complex process. The current IRP process is made more difficult by combining multiple utilities into one process and administering a proceeding, with filings located in one docket. For example, individuals and businesses who are customers of only one utility but not another may be dissuaded from engaging in the IRP process because they are uncertain about how to engage with only their utility when multiple utilities are included in a single docket. Evaluating a single utility's IRP within a separate docket would provide clarity for customers and a more meaningful opportunity to participate.

Arizona is not unique in its handling of IRPs concurrently; however, other states in the West have recognized a more individualized approach. For example, in New Mexico, N.M. Admin. Code 17.7.3.8 mandates that IRPs occur on a staggered basis. New Mexico also has three different utilities, and so Public Service Company of New Mexico filed its IRP in 2023, Southwestern Public Service Company will file in 2024, and El Paso Electric Company will file in 2025. This approach has a multitude of benefits, including less concentrated workload for Commission Staff, greater resources dedicated to utilities individually, clarity in the requirements for each utility, and flexibility in the Commission's approach to each IRP.

IV. Conclusion

WRA recommends APS and the Commission undertake the following actions:

1. In its May Response to Stakeholder Comments APS should refine and update its load growth assumptions.

2. In order to reduce costs for customers, in its May Response to Stakeholder Comments, APS should select the Four Corners Coal Exit 2028 as its preferred portfolio. The Commission should acknowledge APS's IRP with the 2028 Early Four Corners Retirement portfolio as its preferred portfolio.
3. In its May Response to Stakeholder Comments, APS should provide a portfolio analysis including assumptions for the operation of a day-ahead energy market.
4. Regardless of which portfolio the Commission acknowledges through this process, the Commission should direct APS to accelerate its procurement of "no-regrets" wind, solar, storage, and DSM resources.
5. The Commission should recognize the importance of the stakeholders in the IRP process and continue to require the RPAC process for future IRP cycles.
6. The Commission should ensure the next IRP cycle avoids unnecessary delays and ensures full utilization of the modeling and stakeholder process. It can do so by establishing deadlines for when software licensing, input data and model portfolios are shared. Specifically, utilities should be required to provide licensing agreements and training with preliminary utility data at least six months in advance of the IRP filing deadline. Preliminary utility data should include inputs and assumptions available at that time, including for existing and generic resources, and should also include data that allows LTCE in a portfolio without hardcoded resource additions. The Commission should also require that utilities provide all updated and finalized modeling data three months before the IRP filing deadline.
7. The Commission should direct APS to conduct a day-ahead market entry impact assessment to inform its next IRP cycle.
8. The Commission should reform the IRP process by staggering the years in which IRPs occur for different utilities to ensure the IRP for each utility is reviewed as a separate and distinct.

RESPECTFULLY SUBMITTED this 31st day of January, 2024.

WESTERN RESOURCE ADVOCATES

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Appendix 1

To	Western Resource Advocates
From	Alex Palomino, Senior Consultant – Energy Strategies
Re	2023 Arizona Public Service IRP Model – Technical Review
Date	January 11th, 2023
Attachments	Appendix A: Review of Modeled Scenario Results

1. Scope & Background

By order of the Arizona Corporation Commission (ACC), Arizona investor-owned utilities made available the planning models employed in the development of their 2023 IRP filing. This memo provides an independent technical review of the Arizona Public Service (AZPS) Aurora Energy Forecasting Software (Aurora) model. This work is focused on APS's Aurora models and their implications for long-term resource planning consistent with their 2023 IRP filing.

APS delivered the Aurora data archive to intervenors on September 25th, 2023, representing the model according to the IRP filed on November 1st. This model archive included a single model representing the APS reference, without scenario change sets. The 8 additional IRP scenarios and 5 sensitivities were not provided by APS to intervenors. Still, the reference model included all input tables, resources, and new resources necessary to run long-term capacity expansion (LTCE) analyses. From this reference model, alternative scenarios were developed to evaluate keys drivers of emissions and cost.

In evaluating the reference and alternative scenarios' portfolio costs, Energy Strategies discovered results that were significantly incongruent with expectation. After consultation with Energy Exemplar Technical Support, it was discovered that APS did not include new, capacity expansion, resources in the output portfolio. Only the existing generation fleet was included in portfolio cost reporting. When asked about this discrepancy, APS explained that their Aurora model does not appropriately account for the fixed costs of existing resources. Therefore, APS calculated their revenue requirements in an undisclosed process. The total portfolio costs reported in this work are indicative of the APS model provided to the intervenor teams and express the cost of new resource expansion among the alternative future scenarios considered.

2. LT Model Scenarios

Alternative scenarios were designed to explore the influence of market participation, resource retirements, and fuel prices on total portfolio costs and CO2 emissions. They are summarized below.

APS Reference Scenario

- **IRP Reference**: Reference LTCE model provided by APS.

WRA Alternative Scenarios

The APS IRP Reference forms the starting point for alternative scenarios modeled below. Only the inputs mentioned in the alternatives deviate from the tables and assumptions given in the IRP Reference.

- **Early Four Corners Retirement**: Copy of the IRP Reference wherein Four Corners is retired 3 years early, in 2028. Note, costs calculated in this include only those inputs provided in the APS reference model. Accordingly, retirement costs and coal contract commitments are not considered.
- **High Gas Price**: Copy of the IRP Reference wherein the input natural gas prices are scaled up according to APS' May 17th RPAC presentation of gas price sensitivities.
  - The ratio between the APS "High Gas" annual price and the model's IRP Reference average annual price was used to scale up the IRP Reference monthly price for each year of the study horizon. On average, this process increased annual gas prices by 57%.
- **Market Expansion:** Copy of the IRP Reference wherein External market link capacity, from the External market, is doubled from 700 MW to 1400 MW. This scenario offers an approximate view of how increased market participation (imports only) could impact APS' resource expansion decisions.
- **No Fossil:** Copy of the IRP Reference wherein Four Corners is retired 3 years early, in 2028, and expansion candidates are limited to non-emitting resources. This scenario removes natural gas and oil resources from consideration, but allows biofuel, geothermal, pumped hydro, battery storage, solar, wind, and advanced nuclear options.
- **Carbon Reduction**: Copy of the IRP Reference wherein an annual CO2 emissions constraint is implemented to enforce compliance with APS' 2020 IRP trajectory.
  - Note, an attempt was made to model an 80% CO2 reduction, relative to 2005 emissions by 2030 scenario, but this proved infeasible. Given the set of inputs, assumptions, constraints, and the goal of minimally invasive changes to the model, a long-term capacity expansion run could not feasibly realize a portfolio to achieve 80% CO2 reduction by 2030.

3. LT Scenario Results

Full scenario results are included in Appendix A.

Note, the capacity expansion results presented in Appendix A, are subject to the quality and comprehensiveness of the model and inputs provided by APS.

4. Key Takeaways

1. **Four Corners can be retired early in 2028 without regret. Doing so reduces portfolio costs and CO2 emissions.** The model retires Four Corners early in both the "Early FC (2028)" scenario and the "No Fossil" scenario.
    a. In the "Early FC" scenario, the model compensates for the loss of firm capacity in 2028 by expanding natural gas capacity earlier in the study horizon. Despite the earlier build of natural gas resources, the "Early FC" scenario results in lower total carbon emissions and a slightly smaller natural gas fleet by 2039.
    b. In the "No Fossil" scenario, the model compensates for the loss of firm capacity in 2028 by expanding storage capacity earlier in the study horizon.
    c. Portfolio cost results show a negative cost (savings) to retiring Four Corners early. These findings are based on the cost assumptions included by APS in their model which may not be inclusive of all aspects of unit retirement costs.
2. **Storage, with wind, will be crucial to achieve carbon emissions consistent with the 2020 IRP trajectory**. Low carbon futures will rely less on new solar expansion. Instead, resource expansion results illustrate the complementary nature of new wind with storage.
    a. The “Carbon Reduction” scenario builds ~2.5x as much wind and ~3.0x as much storage and 1/3 of the solar capacity when compared with the IRP Reference.
    b. In a solar rich state such as Arizona, the combination of wind + storage offers resource diversity to help meet system needs.
3. **Aggressive Energy Efficiency adoption is selected by all scenarios but the "IRP Reference" and the "Market Expansion" scenarios.**
    a. The aggressive adoption seen in most of the scenarios modeled results in 50% more DSM capacity (~1 GW). This selection indicates the role of demand side management across a diversity of futures.
    b. The lack of aggressive demand side management expansion in the "Market Expansion (2x)" scenario suggests that DSM adoption provides a capacity benefit to the APS system.
4. **Lowest cost carbon reductions can be best achieved by early action.**
    a. Over the first 10 years of the study (2025-2034), the “Carbon Reduction” scenario costs 12% more than the IRP reference while reducing CO2 emissions by 25%.
    b. Beyond 2034, the model has limited information regarding the reality of candidate, non-emitting resources. In these final years, the “Carbon” scenario accrues 76% of its cost premium.
5. **Limiting expansion candidates to non-emitting resources, as in the “No Fossil” scenario, provides a hedge against gas price risk and volatility.**

a. The cost parity of the "No Fossil" and "High Gas" scenarios, $39.10B and $39.79B respectively, illustrates how APS can reduce its exposure to fuel prices and reduce emissions by leveraging clean generation resources.

5. Key Dates

- **June 13th, 2023**: APS/TEP host Joint RPAC Modeling Workshop.
- **June 26th, 2023**: APS shares v1 of their Aurora Model Archive with intervenors.
- **June 29th, 2023**: APS/TEP IRP Kickoff meeting. APS provides review of their model with slides demonstrating features of their model. TEP fields open questions from intervenors.
- **July 11th, 2023**: APS hosts a Resource Modeling Committee meeting with Energy Exemplar to review Aurora Capacity Expansion and APS' approach.
- **August 11th, 2023**: APS shares v2 of their Aurora Model Archive with intervenors.
- **September 25th, 2023**: APS shares v4 of their Aurora Model Archive with intervenors. Note, v4 includes updates from an interim v3 model that was not shared with intervenors.
- **October 13th, 2023:** APS uploads their 2023 IRP Results Dashboard. This dashboard provided comparative results tables for their modeled scenarios.
- **November 1st, 2023**: APS files their IRP.

Appendix 2

2023 APS IRP Review

Aurora Model Review and Alternative Futures

January 2024

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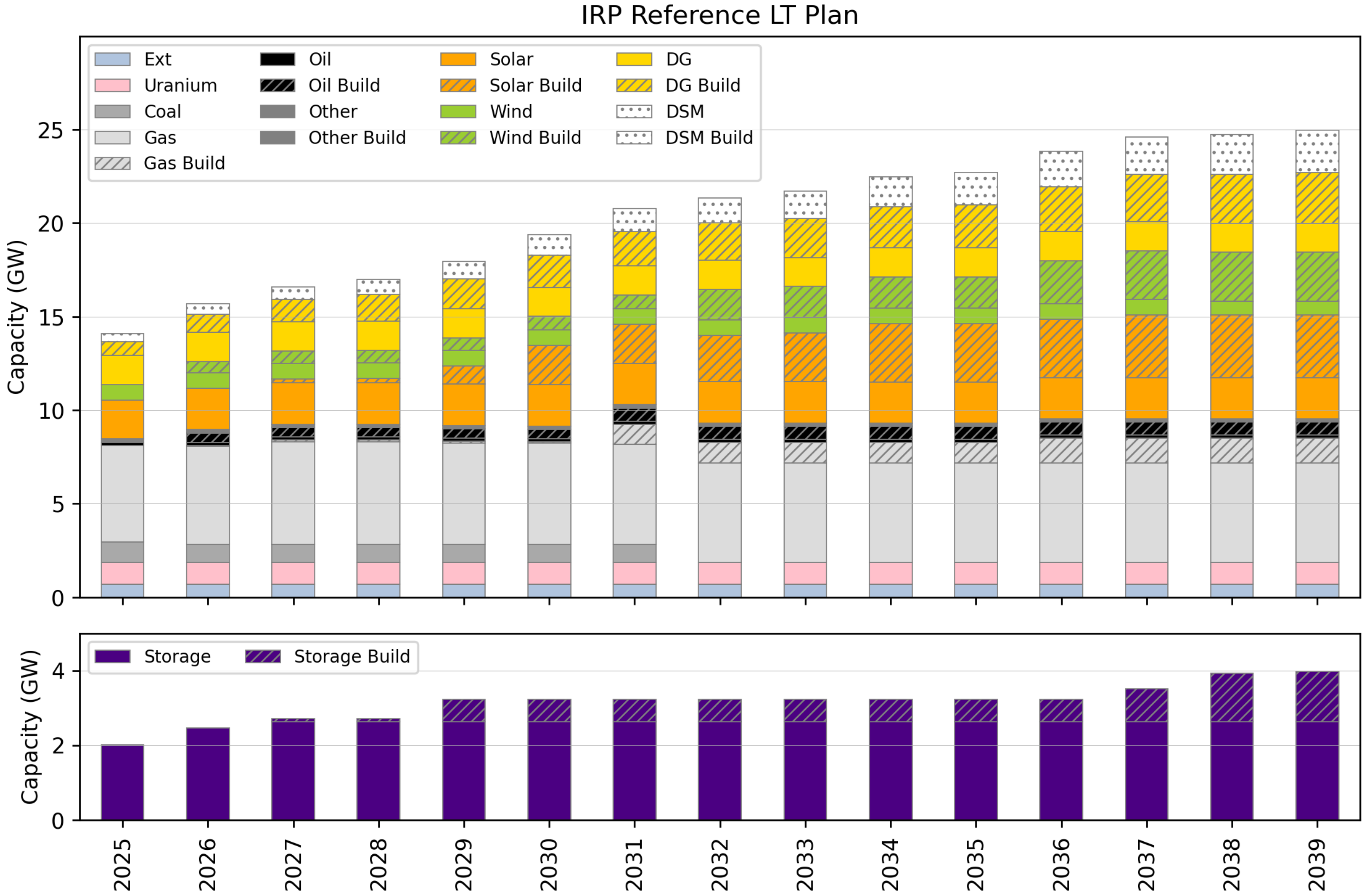
GridLAB

ENERGY STRATEGIES

Establishing a baseline

- **The IRP Reference plan represents APS expectation for resource expansion over the study horizon.**
  - Resource capacities presented illustrate the out-of-the-box results of the APS v4 Aurora Model.
- **Capacity expansion highlights:**
  - Retire 1.1 GW of Coal capacity (Four Corners) in 2031.
  - Builds 1.3 GW of Natural Gas capacity.
  - Builds 3.3 GW of Solar capacity.
  - Builds 2.6 GW of Wind capacity.
  - Builds 2.3 GW of Distributed Generation.
  - Builds 1.3 GW of Storage capacity.
  - Expands Energy Efficiency Programs by 2.3 GW.
  - Peak Load increased 3.9 GW.

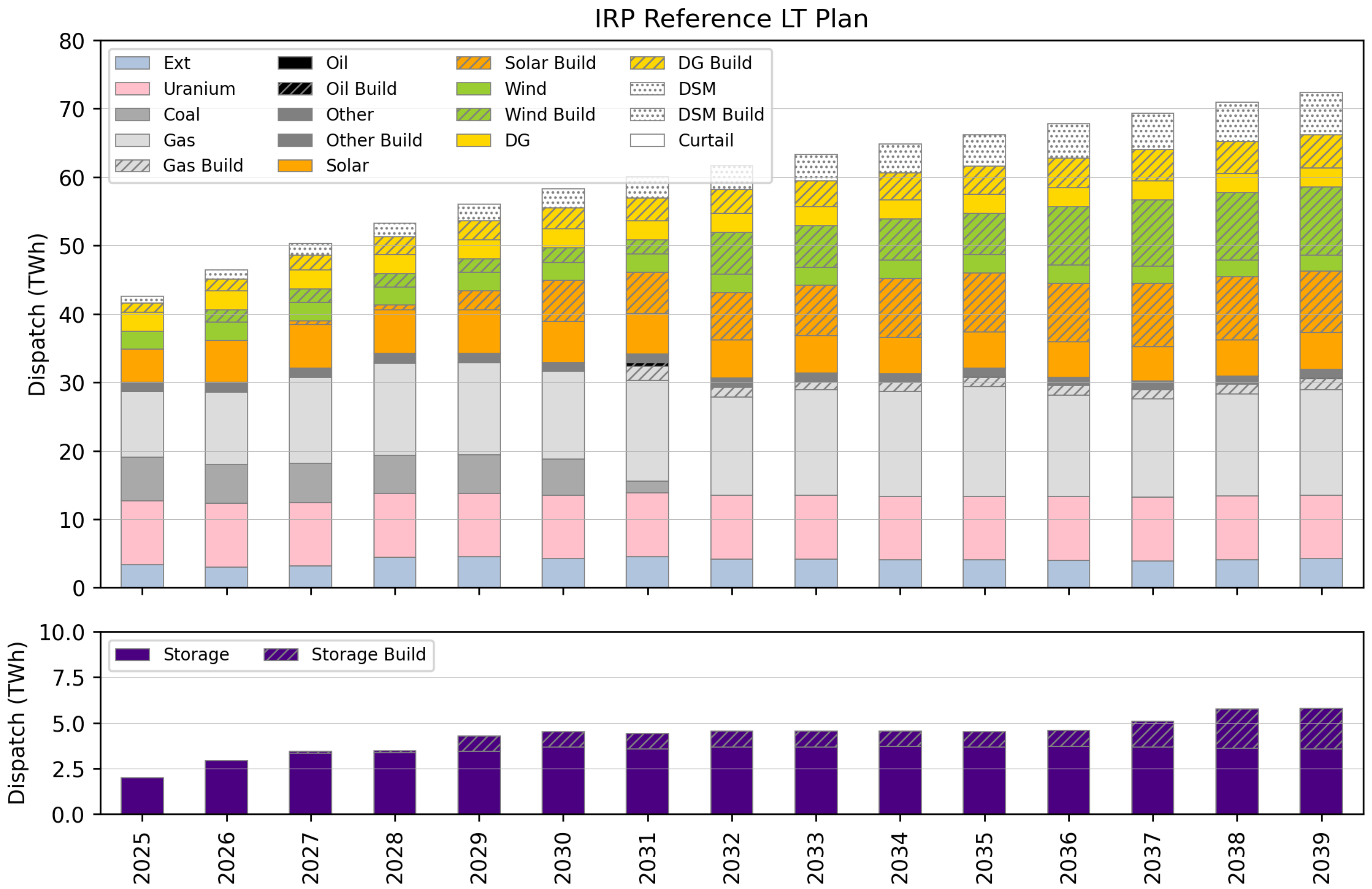


Establishing a baseline

- **The dispatch of each resource type illustrates how the system utilizes the installed capacity.**
  - From 2025 to 2039, the APS system reduces the generation share of dispatchable resources and increases its utilization of Solar, Wind, Distributed Generation, Demand Side Management, and Storage.

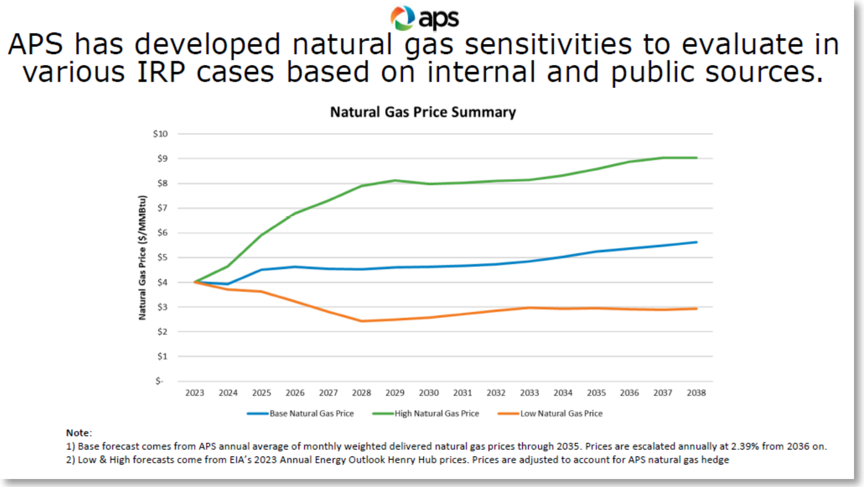
Year	Ext	Uranium	Coal	Gas	Oil
2025	8%	21%	14%	21%	0%
2030	7%	15%	8%	20%	0%
2035	6%	13%	0%	25%	0%
2039	5%	12%	0%	22%	0%

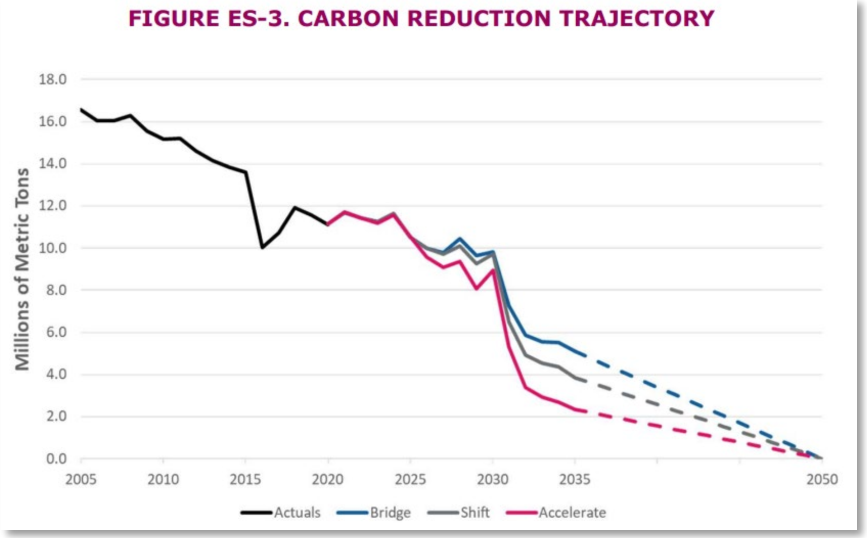
Year	Other	Solar	Wind	DG	DSM	Storage
2025	3%	11%	6%	9%	2%	4%
2030	2%	19%	8%	9%	4%	7%
2035	2%	20%	12%	10%	7%	6%
2039	1%	18%	16%	10%	8%	7%



Modeling alternatives

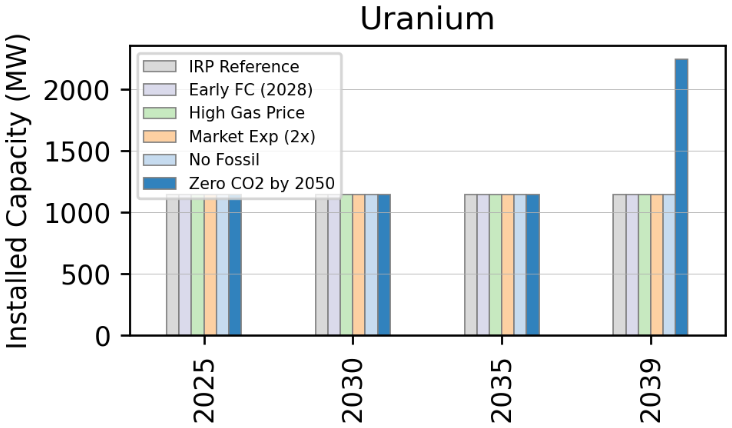
- **Early Four Corners Retirement:**
  - Retires Four Corners 3 years early in 2028.
    - Caveat: Scenario costs include only those inputs provided in the APS reference model. Accordingly, retirement costs and coal contract commitments are not considered.
- **High Gas Price**
  - Scales up natural gas prices by the ratio of the “High Gas Price” trajectory and the Model’s AZ Monthly NG Price.
    - Based on the May 17 RPAC Natural Gas Price Summary presentation.
- **Market Expansion**
  - Doubles the 2023 Import Limit from 700 to 1400.
- **No Fossil**
  - Retires Four Corners 3 years early in 2028 and limits expansion candidate resources to non-Fossil options.
- **Carbon Reduction**
  - Zero CO_2 by 2050: Imposes an annual CO_2 emissions constraint compliant with the 2020 IRP.

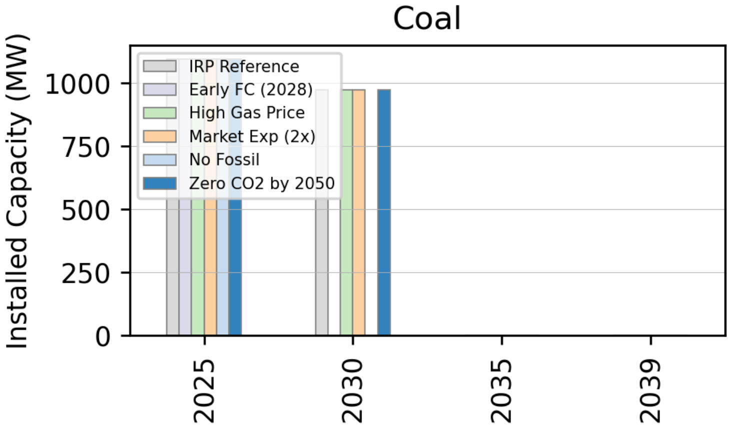


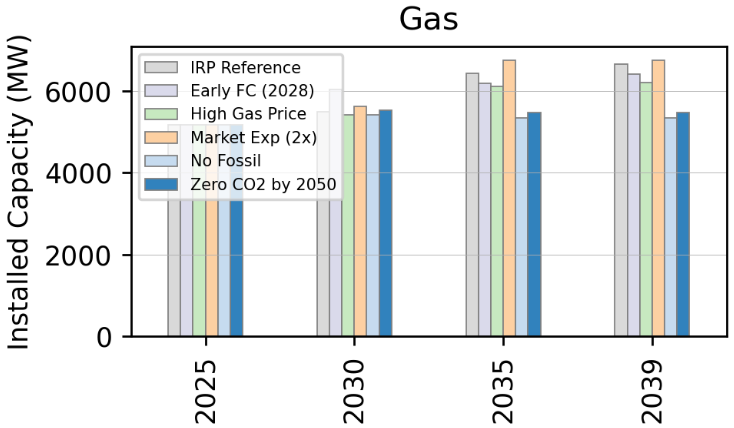


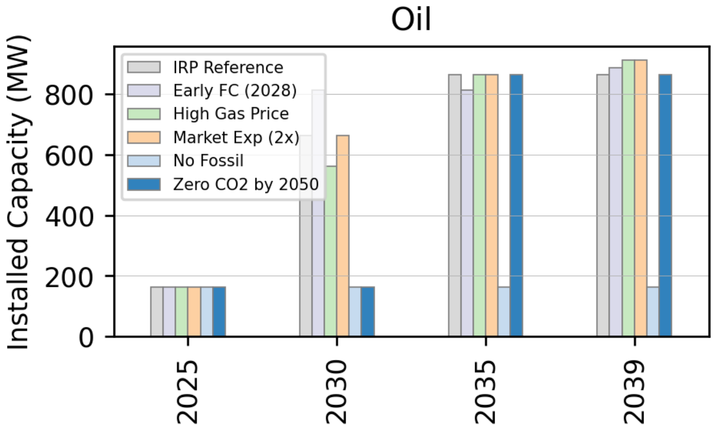
Scenario Results

Resource build comparisons



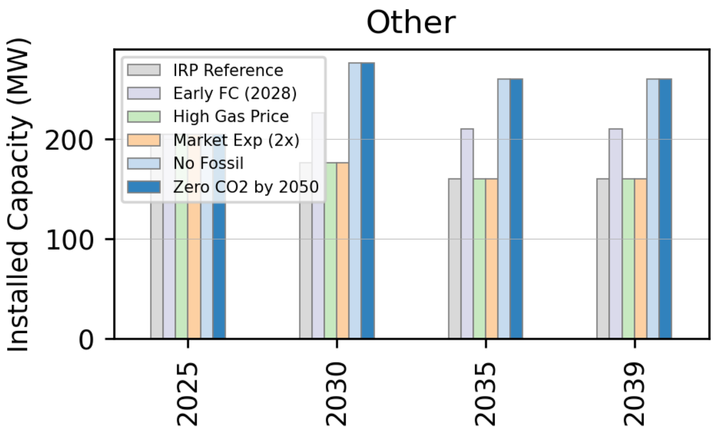


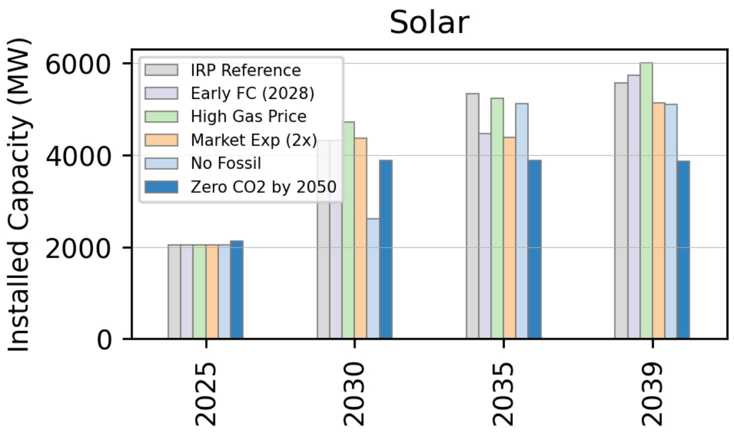




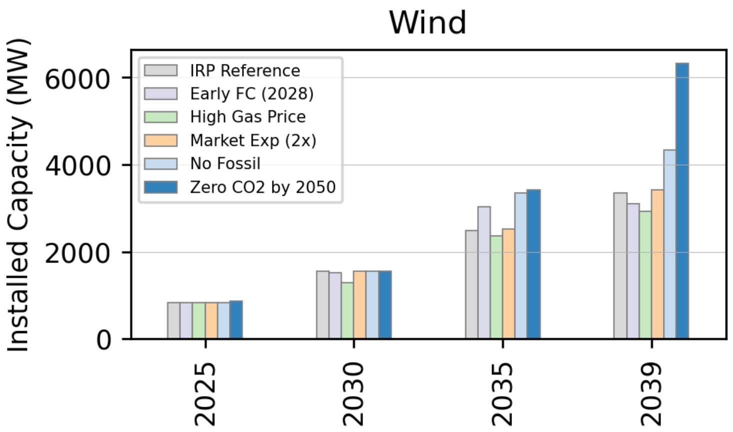
- **The Zero CO2 by 2050 scenario builds additional advanced nuclear facilities to meet CO2 emissions constraints late in the study horizon.**
- **Otherwise, conventional resource build outs are consistent**
  - The Early Four Corners retirement (2028) demonstrates the reduction in coal capacity in 2030
  - Oil capacity expansion is eliminated in the No Fossil case.
    - Note: Oil resources represent micro grid facilities.

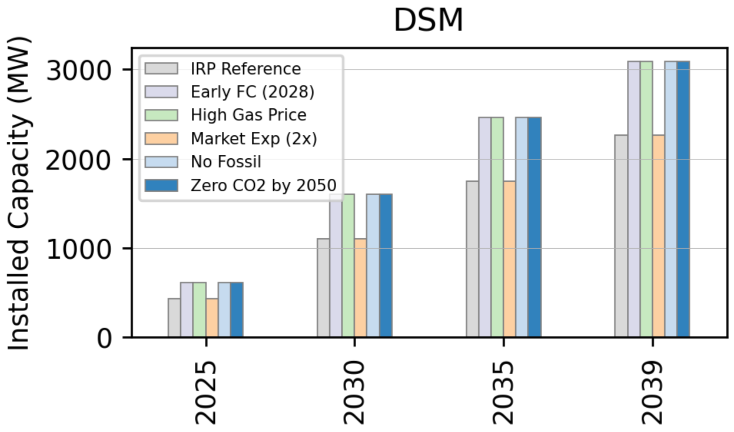
Resource build comparisons

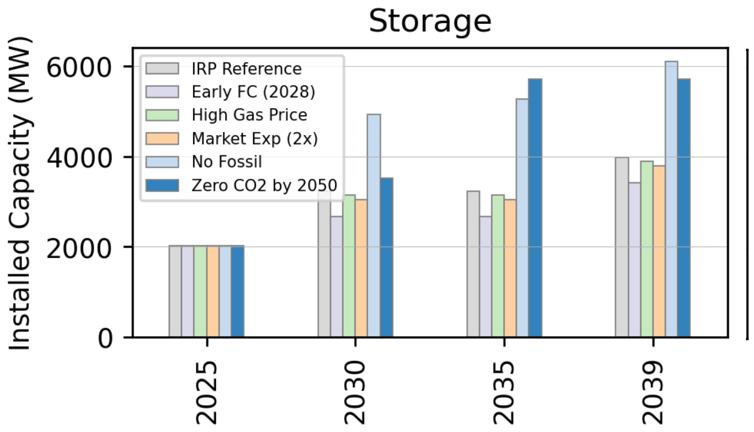




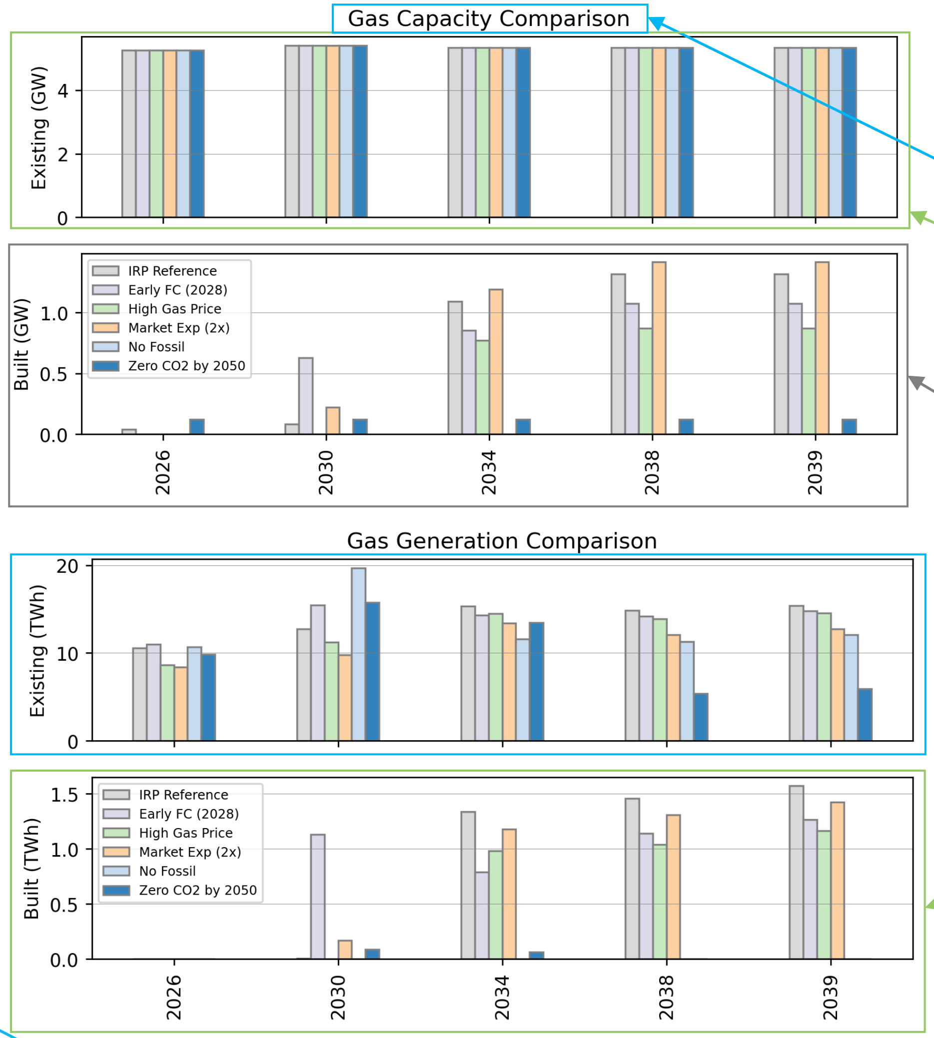
- **Builds are more varied across non-conventional resources**
  - Additional "Other" resources are built in response to the loss of firm capacity in the Early Four Corners retirement and low carbon scenarios (reduced gas)
    - Note: "Other" resource include biogas, geothermal, and purchase contract resources
  - The low carbon scenarios demonstrate the complementary nature of wind, DSM, and battery storage expansion
    - Storage buildout is a keystone of a low carbon future.
  - The DSM build out depicts two discrete capacity trajectories (moderate and aggressive EE program adoption)







A closer look at resource capacities and generation



- **The following slides present the total installed capacity and generation of both existing and built, or expansion, resources across all study scenarios**

- **Resource Name**
- **Total installed capacity (GW) of existing resources by year**
  - Note, the APS model does not consider economic retirements
  - Therefore, the installed capacity of existing resources is consistent across all scenarios and resource types
- **Total installed capacity of built, or expanded, resources by year**
  - Built resources are those expanded by the model during long-term capacity expansion

- **Total annual generation (TWh) of existing resources by year**
- **Total annual generation of built, or expanded, resources by year**

ENERGY STRATEGIES

A closer look at resource capacity and generation

- **Total installed capacity (GW) of existing and built resources in comparison to the Reference**
  - Note, the APS model does not consider economic retirements
  - Therefore, the installed capacity of existing resources is consistent across all scenarios and resource types
- **For example, the Early FC scenario builds 0.28 GW less capacity than the Reference by the end of the study horizon**

2039 Capacity Comparison to Reference

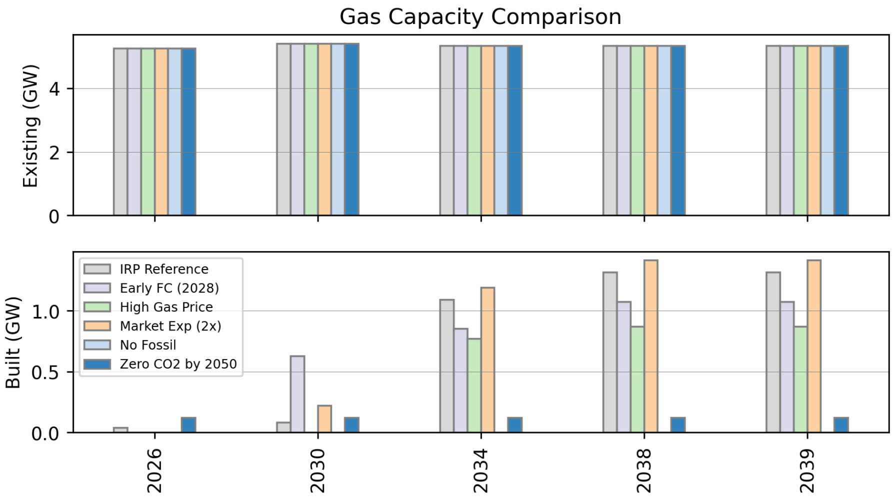
Scenario	Existing	Built
Early FC	0.00 GW	-0.28 GW
High Gas Price	0.00 GW	-0.44 GW
Market Exp (2x)	0.00 GW	0.10 GW
No Fossil	0.00 GW	-1.31 GW
Zero CO2 by 2050	0.00 GW	-1.19 GW

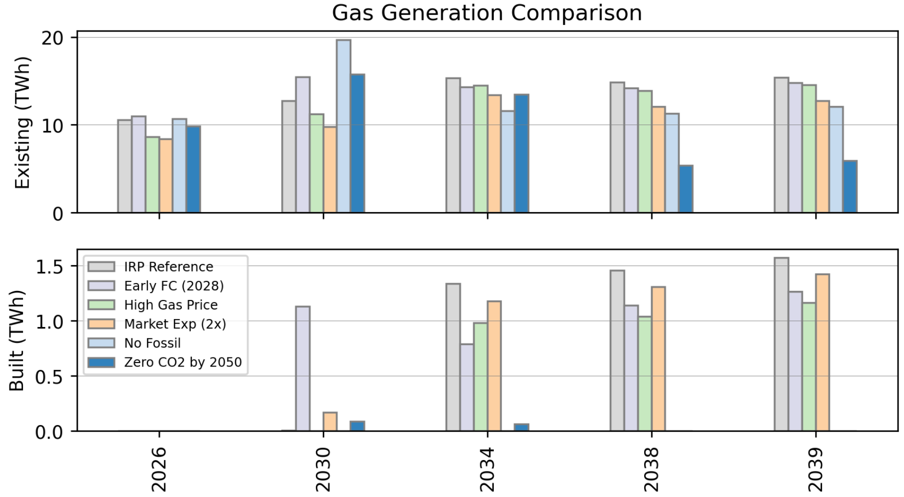
- **Total annual generation (TWh) of existing and built resources in comparison to the Reference**
- **For example, the Early FC scenario generates 0.70 TWh less than the Reference in the last year of the study (2039)**
  - This reduction in generation is split between a reduction in the existing resource fleet (0.53 TWh less) and the built fleet (0.17 TWh less)

2039 Generation Comparison to Reference

Scenario	Existing	Built	Total
Early FC	-0.53 TWh	-0.17 TWh	-0.70 TWh
High Gas Price	-0.89 TWh	-0.41 TWh	-1.30 TWh
Market Exp (2x)	-2.70 TWh	-0.15 TWh	-2.85 TWh
No Fossil	-3.36 TWh	-1.57 TWh	-4.94 TWh
Zero CO2 by 2050	-9.51 TWh	-1.57 TWh	-11.08 TWh

A closer look at Natural Gas capacity and generation





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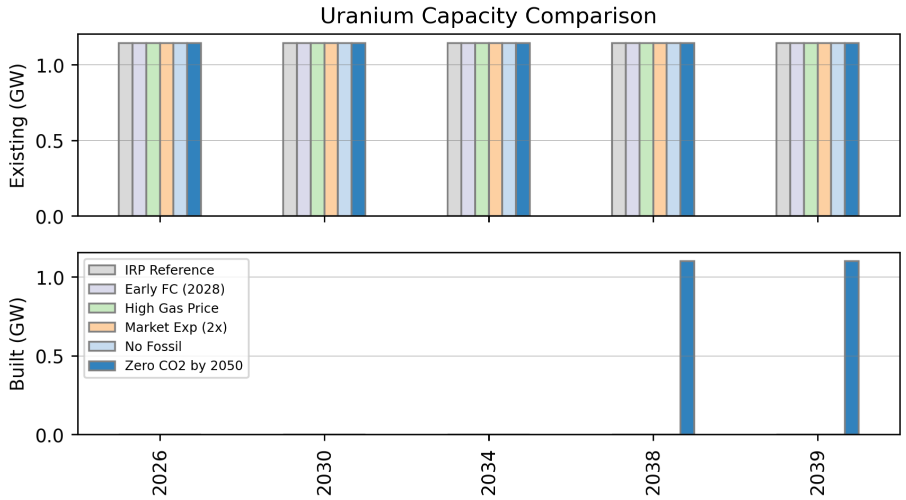
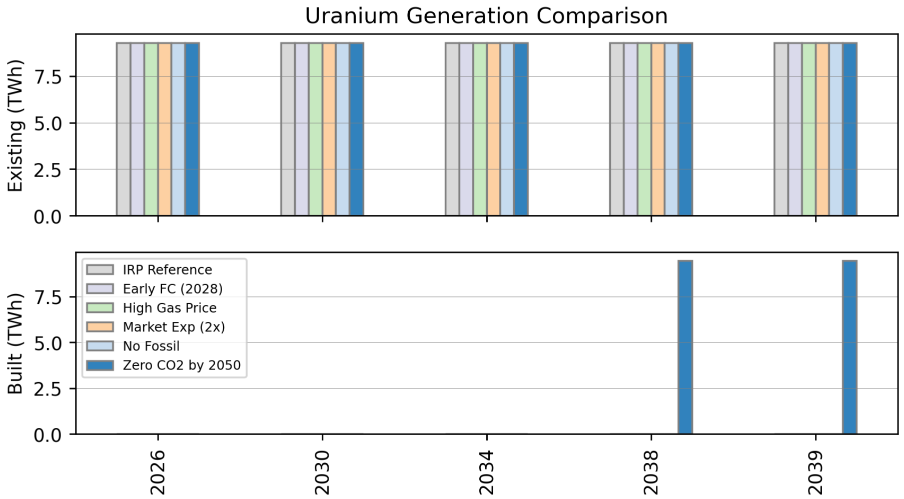
A closer look at Uranium capacity and generation





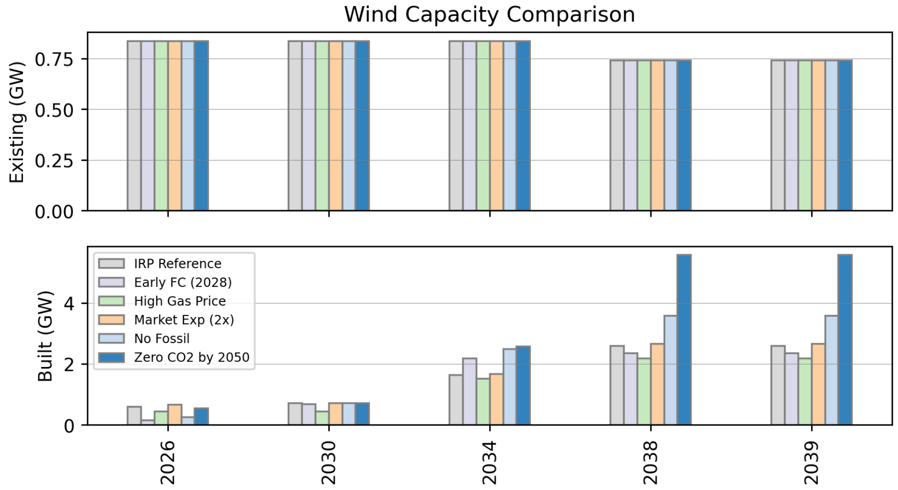
2039 Capacity Comparison to Reference

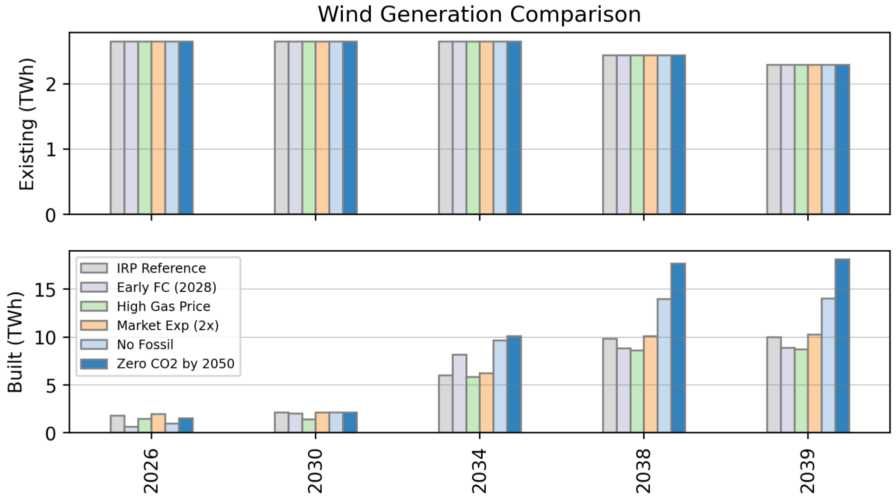
Scenario	Existing	Built
Early FC	0.00 GW	0.00 GW
High Gas Price	0.00 GW	0.00 GW
Market Exp (2x)	0.00 GW	0.00 GW
No Fossil	0.00 GW	0.00 GW
Zero CO2 by 2050	0.00 GW	1.10 GW

2039 Generation Comparison to Reference

Scenario	Existing	Built	Total
Early FC	0.00 TWh	0.00 TWh	0.00 TWh
High Gas Price	0.00 TWh	0.00 TWh	0.00 TWh
Market Exp (2x)	0.00 TWh	0.00 TWh	0.00 TWh
No Fossil	0.00 TWh	0.00 TWh	0.00 TWh
Zero CO2 by 2050	0.00 TWh	9.44 TWh	9.44 TWh

A closer look at Wind capacity and generation





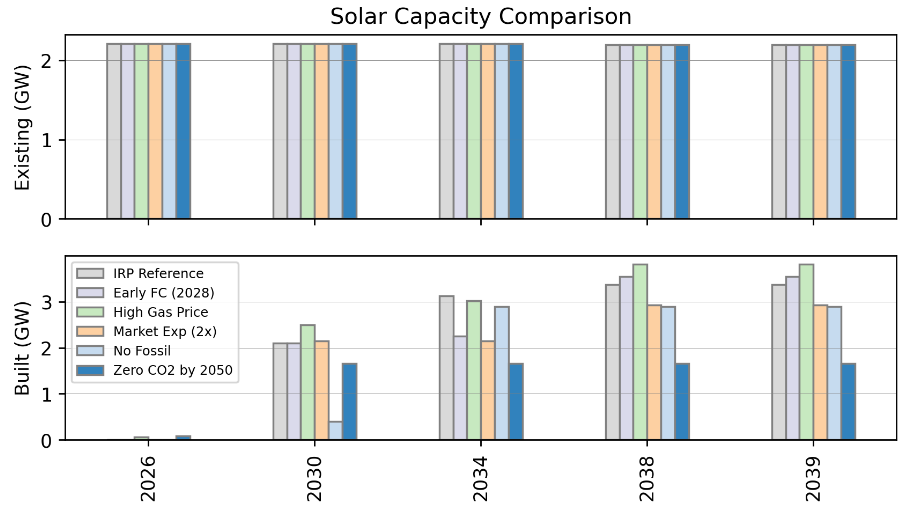
2039 Capacity Comparison to Reference

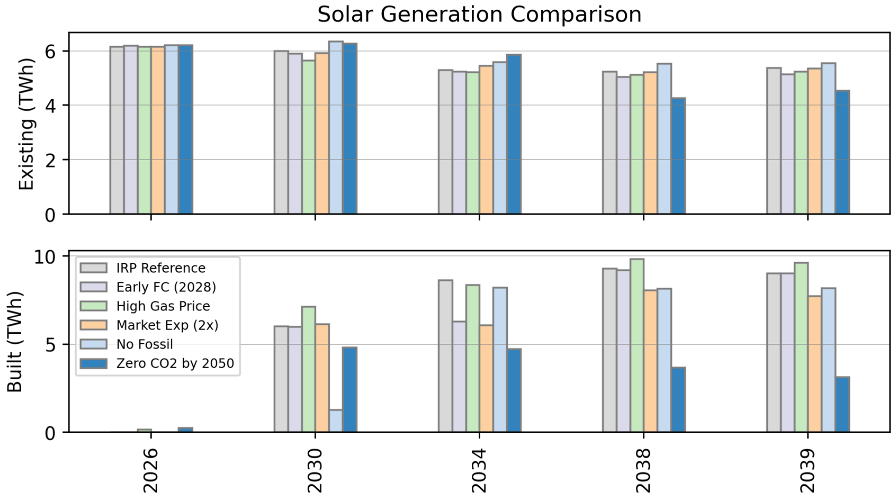
Scenario	Existing	Built
Early FC	0.00 GW	-0.25 GW
High Gas Price	0.00 GW	-0.42 GW
Market Exp (2x)	0.00 GW	0.07 GW
No Fossil	0.00 GW	0.98 GW
Zero CO2 by 2050	0.00 GW	2.98 GW

2039 Generation Comparison to Reference

Scenario	Existing	Built	Total
Early FC	0.00 TWh	-1.08 TWh	-1.08 TWh
High Gas Price	0.00 TWh	-1.24 TWh	-1.24 TWh
Market Exp (2x)	0.00 TWh	0.29 TWh	0.29 TWh
No Fossil	0.00 TWh	4.05 TWh	4.05 TWh
Zero CO2 by 2050	0.00 TWh	8.14 TWh	8.14 TWh

A closer look at Solar capacity and generation





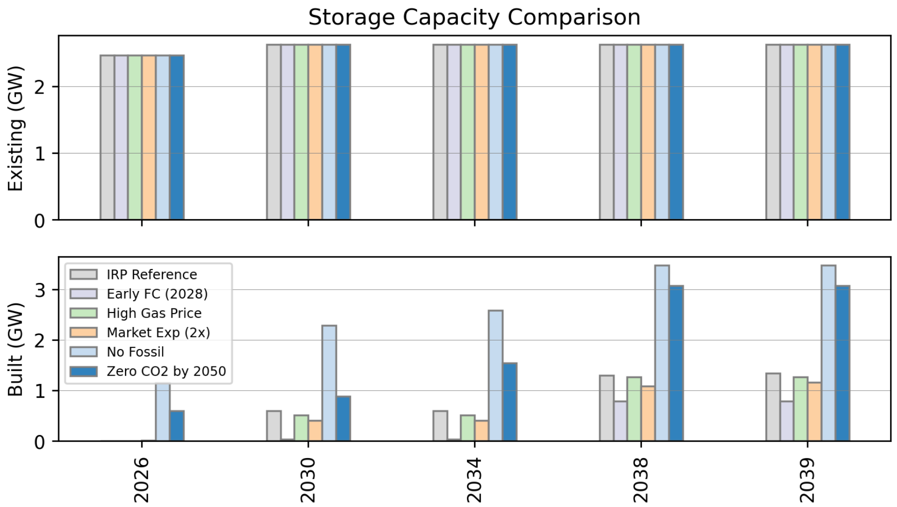
2039 Capacity Comparison to Reference

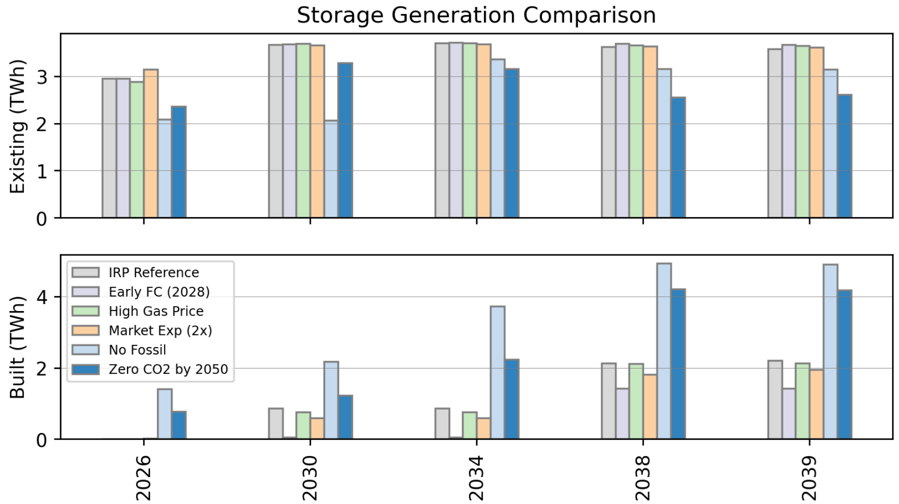
Scenario	Existing	Built
Early FC	0.00 GW	0.18 GW
High Gas Price	0.00 GW	0.44 GW
Market Exp (2x)	0.00 GW	-0.44 GW
No Fossil	0.00 GW	-0.47 GW
Zero CO2 by 2050	0.00 GW	-1.71 GW

2039 Generation Comparison to Reference

Scenario	Existing	Built	Total
Early FC	-0.23 TWh	-0.01 TWh	-0.24 TWh
High Gas Price	-0.14 TWh	0.59 TWh	0.44 TWh
Market Exp (2x)	-0.02 TWh	-1.29 TWh	-1.31 TWh
No Fossil	0.18 TWh	-0.85 TWh	-0.67 TWh
Zero CO2 by 2050	-0.83 TWh	-5.90 TWh	-6.73 TWh

A closer look at Storage capacity and generation





2039 Capacity Comparison to IRP

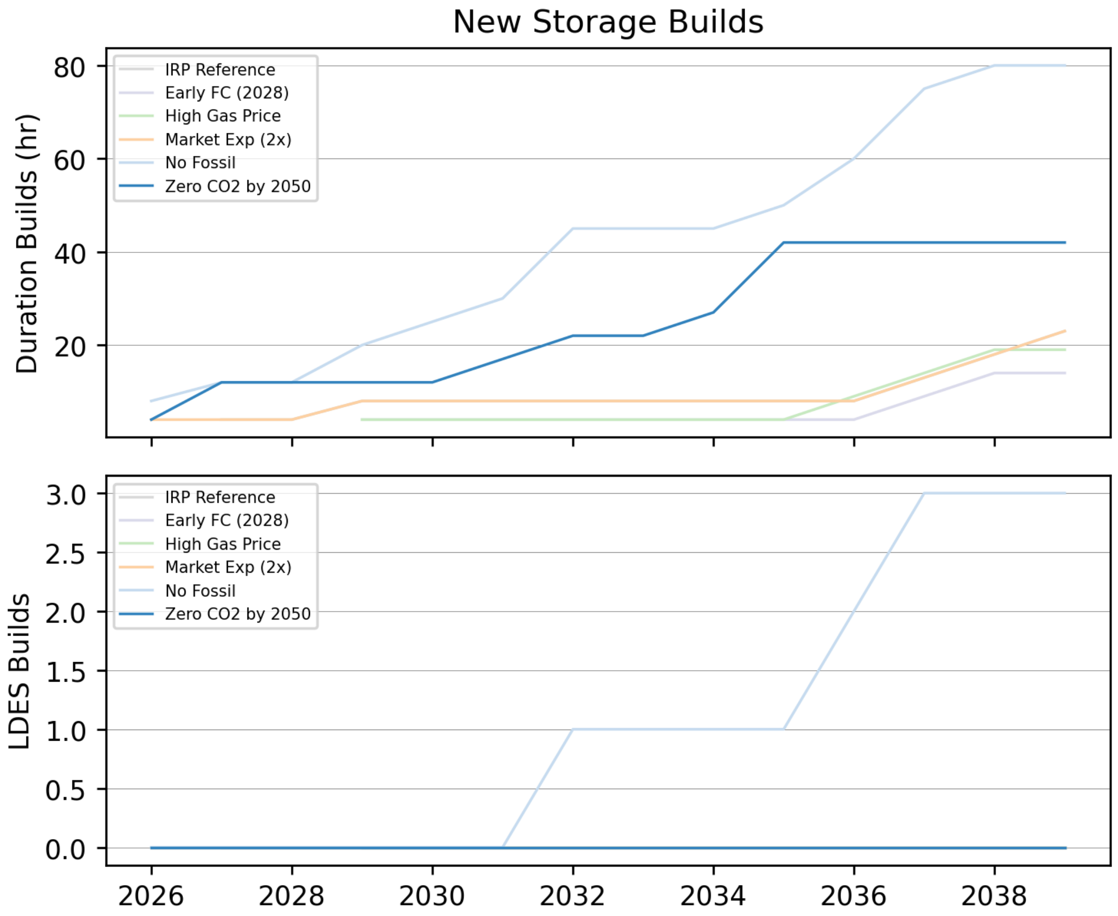
Scenario	Existing	Built
Early FC	0.00 GW	-0.51 GW
High Gas Price	0.00 GW	-0.07 GW
Market Exp (2x)	0.00 GW	-0.18 GW
No Fossil	0.00 GW	2.13 GW
Zero CO2 by 2050	0.00 GW	1.73 GW

2039 Generation Comparison to IRP

Scenario	Existing	Built	Total
Early FC	0.07 TWh	-0.73 TWh	-0.66 TWh
High Gas Price	0.06 TWh	-0.08 TWh	-0.02 TWh
Market Exp (2x)	0.03 TWh	-0.25 TWh	-0.23 TWh
No Fossil	-0.44 TWh	2.70 TWh	2.26 TWh
Zero CO2 by 2050	-0.97 TWh	1.99 TWh	1.01 TWh

Storage build duration comparison

- **Available New Resources in the Model**
  - ESS 4H: 4-hour duration
  - ESS 5H: 5-hour duration
  - Pumped Hydro: 10-hour duration
  - CAES: 24-hour duration (inferred)
- **Background**
  - Duration Builds (h) plots the aggregate storage duration installed per year across scenarios.
  - LDES Builds plot the count of long duration energy storage (LDES) resources.
    - Note: LDES are those resources with more than 5 hours of duration.
- **Energy storage is necessary to achieve a low-carbon future**
  - Both the Zero CO2 and No Fossil scenarios build 2-4x more storage, by aggregate duration, than all other scenarios.
  - Long duration energy storage resources are necessary to make a No Fossil expansion future possible.



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Resource generation comparisons

- **Generation by resource type offers a high-level view of each scenario's portfolio operation**
  - The Zero CO2 scenario reduces annual natural gas generation by 14% as a share of total generation >
  - The Zero CO2 scenario build approximately 1 GW of new nuclear capacity (SMR and Advanced Nuclear units). >
  - The Market Expansion scenario realizes a doubling in market imports (as designed) >
  - Solar generation is depressed in the Zero CO2 scenario due to significant wind and storage participation (previously observed) >
  - Wind generation increases in the No Fossil and Zero CO2 scenarios (in concert with the capacity expansion trends previously observed) >
  - The IRP Reference and Market Expansion scenarios rely the least upon DSM generation >

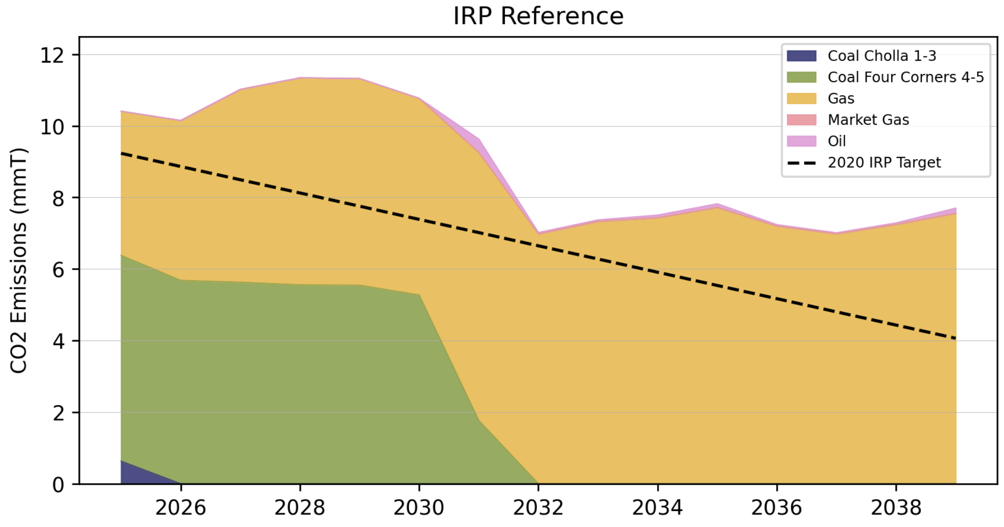
2039 Generation Share

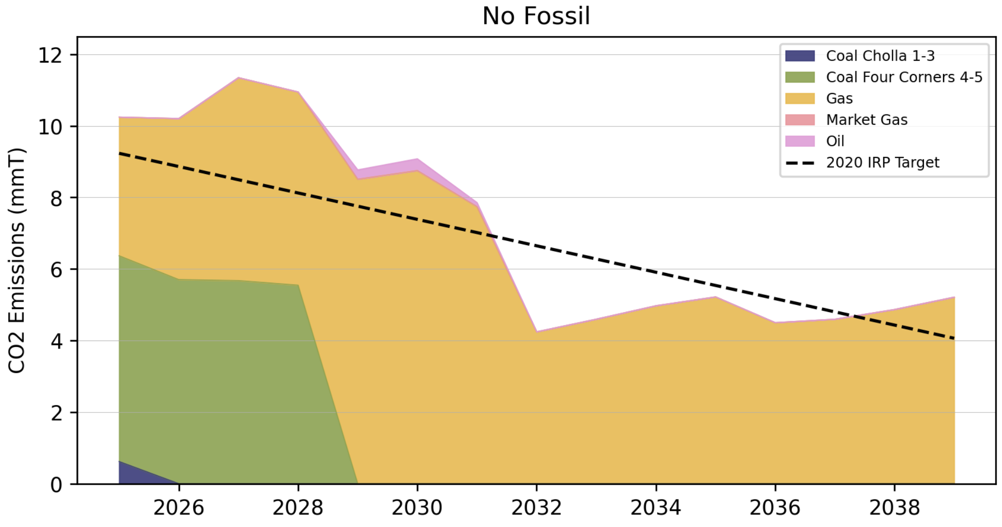
Generation Share (%)	IRP Reference	Early FC (2028)	High Gas Price	Market Exp (2x)	No Fossil	Zero CO2 by 2050
Coal	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Oil	0.3%	0.1%	0.1%	0.0%	0.0%	0.0%
Gas	23.5%	22.2%	21.7%	19.6%	16.6%	8.1%
Uranium	12.8%	12.9%	12.8%	12.8%	12.8%	25.8%
Other	1.6%	1.8%	1.6%	1.6%	2.0%	2.0%
Ext	5.9%	5.7%	5.9%	11.5%	5.4%	3.2%
DG	10.6%	10.6%	10.6%	10.6%	10.5%	10.6%
Solar	19.9%	19.6%	20.5%	18.1%	18.9%	10.5%
Wind	17.0%	15.5%	15.2%	17.4%	22.4%	28.1%
DSM	8.5%	11.6%	11.6%	8.5%	11.5%	11.6%

Carbon emissions

- **In their 2020 IRP, APS committed to goal of zero CO2 emissions by 2050.**
  - Explicitly: “In 2019, APS had reduced its carbon dioxide emissions to 12.3 million metric tons, a 26% decline from 2005 levels (16.61 MMT). The Company expects to further reduce emissions by another 7-8 million metric tons by 2030 and totally eliminate them by 2050.”
  - The IRP Reference Case does not align with APS’ 2020 IRP goals for CO2 emissions reduction.
    - By 2039, the IRP Reference Case reduces CO2 emissions by 54% and emits 34 mmT more CO2 than the 2020 IRP trajectory.

- **The No Fossil case restricts build candidates to only non-emitting resources.**
  - The No Fossil Case partially aligns with the APS’ 2020 IRP goals for CO2 emissions reduction.
    - By 2039, the No Fossil cases reduces CO2 emissions by 69% (compared to a 2005 baseline) and emits 7 mmT more CO2 than the 2020 IRP trajectory over the study horizon.
    - A reduction of 27 mmT CO2 at an increased cost of $4.9B.





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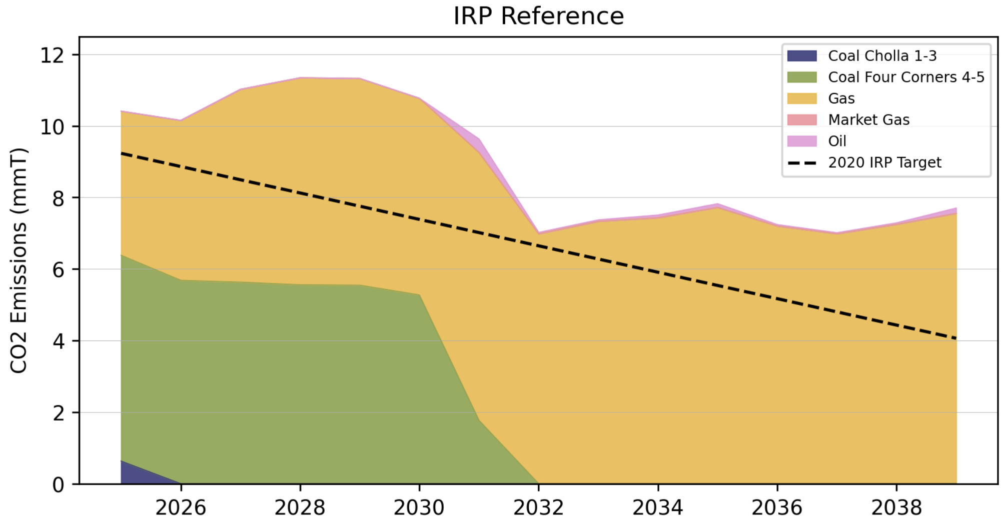
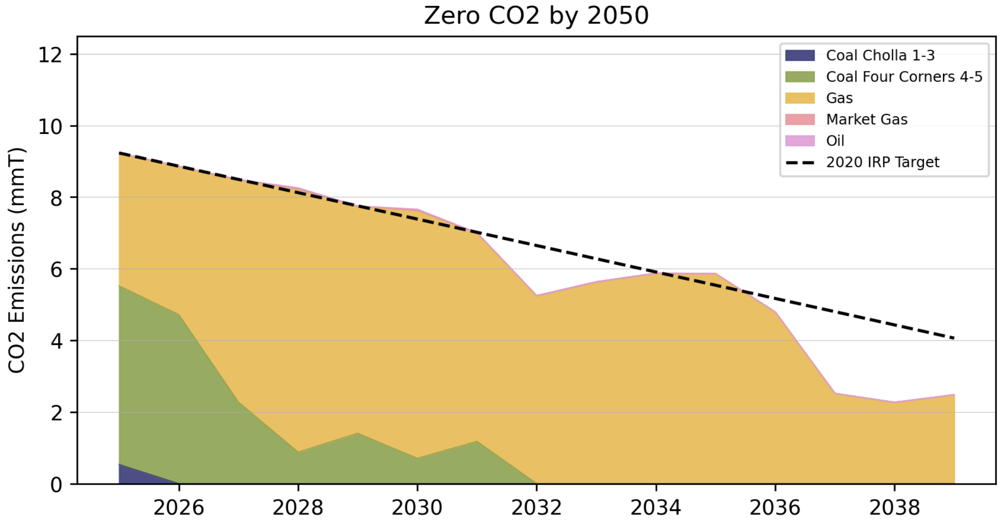
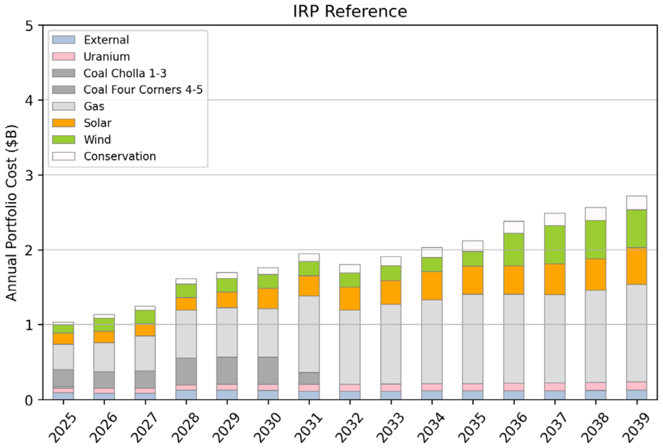
  - The IRP Reference Case does not align with APS' 2020 IRP goals for CO2 emissions reduction.
    - By 2039, the IRP Reference Case reduces CO2 emissions by 54% and emits 34 mmT more CO2 than the 2020 IRP trajectory.

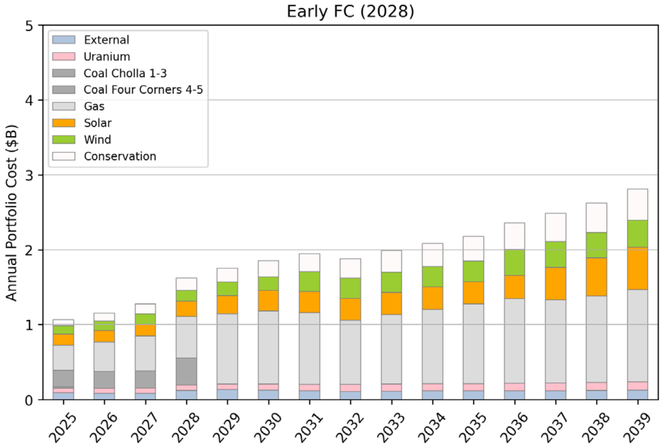


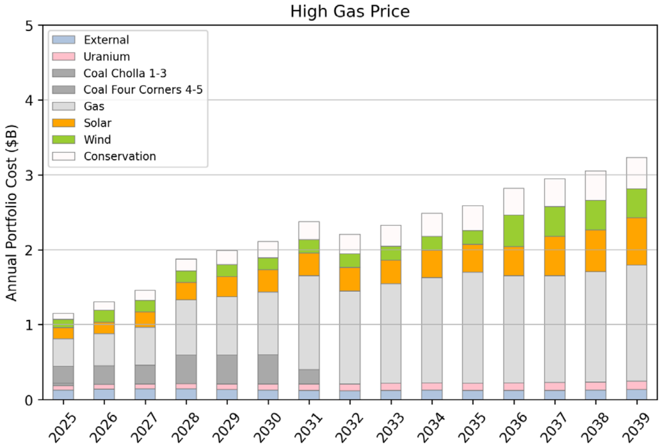
- **The Zero CO2 by 2050 case imposes an annual emissions limit consistent with the 2020 IRP trajectory.**
  - The Zero CO2 Case predominately aligns with the APS' 2020 IRP goals for CO2 emissions reduction (save for 2 years where the CO2 limit constraint was relaxed slightly).
    - By 2039, the Zero CO2 cases reduces emissions by 85% (compared to a 2005 baseline) and emits 8 mmT LESS CO2 than the 2020 IRP trajectory over the study horizon.
    - A reduction of 42 mmT CO2 at an increased cost of $9.8B.

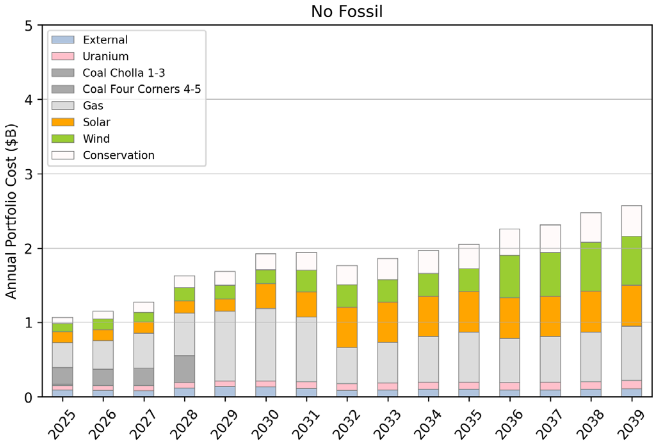


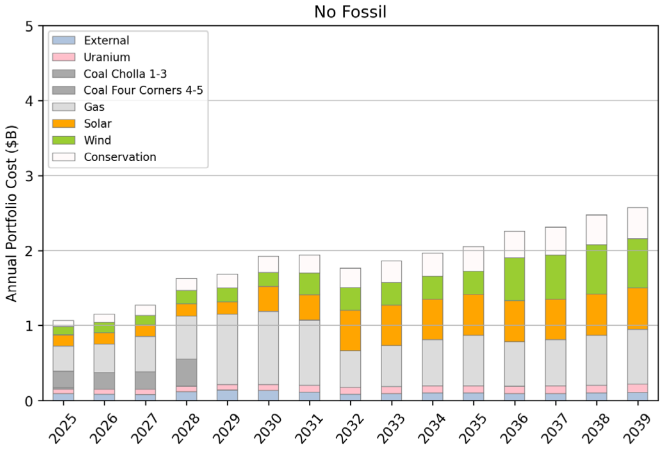
Annual portfolio costs

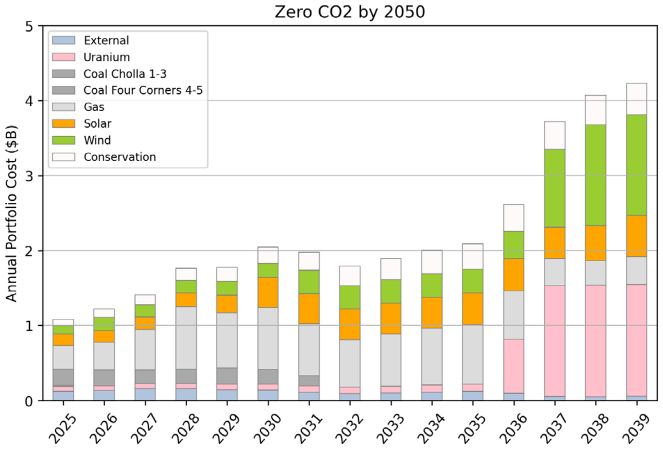












Scenario summary

- **The IRP reference case results in moderate costs, but high CO2 emissions when compared to the alternatives reviewed**
  - Retiring Four Corners 3 years early slightly reduces CO2 emissions and costs.
    - Over the study horizon, Four Corners can be retired early with minimal impact to the resource plan.
  - The High Gas Price scenario illustrates the limited effectiveness of fuel prices to reduce CO2 emissions.
    - Results indicate only a slight to moderate reduction in CO2 emissions with a significant impact on scenario costs.
  - Increasing market imports offers the APS system significant cost and moderate emissions savings.
  - Limiting resource expansion to non-fossil resources results in reduce costs and significant reductions in CO2 emissions.
  - The Zero CO2 2020 IRP scenario represents significant emissions savings consistent with the 2020 IRP trajectory and increased costs.
    - Note: Increased costs are driven by the adoption of expensive, non-emitting nuclear facilities at the very end of the study horizon.

Scenario	Total Portfolio Cost ($B)	Storage Generation (TWh)	CO2 Reduction (% 2005)[1]	Carbon Abatement ($/mT)[2]
IRP Reference	34.20	64.45	53.64	0.00
Early FC (2028)	33.73	56.63	57.00	-29.29
High Gas Price	39.79	64.17	58.39	522.98
Market Exp (2x)	32.37	62.13	62.24	-86.47
No Fossil	39.10	85.66	68.62	181.77
Zero CO2 by 2050	43.97	74.66	85.04	234.48

(1) APS emitted 16.6 mmT of CO2 in 2005 according to their 2020 IRP.

(2) Carbon abatement is the amount of carbon removed relative to the IRP reference divided by the total portfolio cost difference (measured in $ per metric Ton CO2).

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Takeaways from alternative portfolios

1. **Four Corners can be retired early in 2028 without regret. Doing so reduces portfolio costs and CO_2 emissions. Four Corners is retired early in both the "Early FC (2028)" scenario and the "No Fossil" scenario.**
   - In the "Early FC" scenario, the model compensates for the loss of firm capacity in 2028 by expanding natural gas capacity earlier in the study horizon. Despite the earlier build of natural gas resources, the "Early FC" scenario results in lower total carbon emissions and a slightly smaller natural gas fleet by 2039.
   - In the "No Fossil" scenario, the model compensates for the loss of firm capacity in 2028 by expanding storage capacity earlier in the study horizon.
   - Portfolio cost results show a negative cost (savings) to retiring Four Corners early.
2. **Storage, with wind, will be crucial to achieve carbon emissions consistent with the 2020 IRP trajectory. Low carbon futures will rely less on new solar expansion. Instead, resource expansion results illustrate the complementary nature of new wind with storage.**
   - The “Zero CO_2 by 2050” scenario builds ~2.5x as much wind and ~3.0x as much storage and 1/3 of the solar capacity when compared with the IRP Reference.
   - In a solar rich state such as Arizona, the combination of wind + storage offers resource diversity to help meet system needs.
3. **Aggressive Energy Efficiency adoption is selected by all scenarios but the "IRP Reference" and the "Market Expansion" scenarios.**
   - The aggressive adoption results in 50% more DSM capacity (~1 GW). This selection indicates the role of demand side management across a diversity of futures.
   - The lack of aggressive demand side management expansion in the "Market Expansion (2x)" scenario suggests that DSM's function as a capacity resource to the APS system.
4. **Lowest cost carbon reductions can be best achieved by early action.**
   - Over the first 10 years of the study (2025-2034), the “Zero CO_2 by 2050” scenario costs 12% more than the IRP reference while reducing CO_2 emissions by 25%.
   - Beyond 2034, the model has limited information regarding the reality of candidate, non-emitting resources. In these final years, the “Zero CO_2 by 2050” scenario accrues 76% of its cost premium.
5. **Limiting expansion candidates to non-emitting resources, as in the “No Fossil” scenario, provides a hedge against gas price risk and volatility.**
   - The cost parity of the “No Fossil” and “High Gas” scenarios, \$39.10B and \$39.79B respectively, illustrates how APS can reduce its exposure to fuel prices and reduce emissions by leveraging clean generation resources.

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Thanks

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