THE HIGH CO$T OF THE APS PLAN TO GO NET ZERO

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AZ LIBERTY NETWORK

Isaac Orr & Mitch Rolling | Always On Energy Research | February 2025

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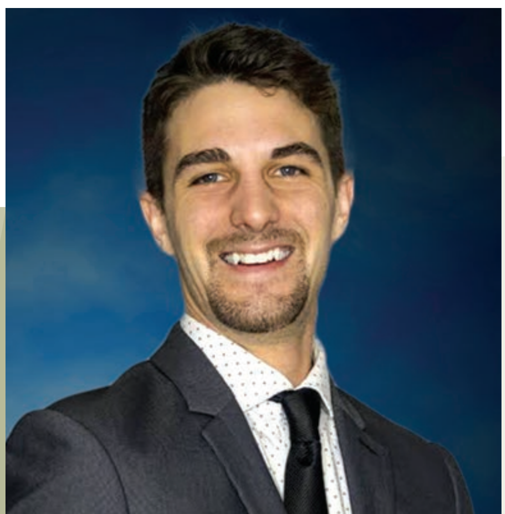
Isaac Orr is a Founder and Vice President of Research at Always On Energy Research, where he conducts energy modeling and writes about energy and environmental issues, electricity policy, and natural resource development. His writings have appeared in The Wall Street Journal, USA Today, the New York Post, The Hill, and many other publications. He and his colleague Mitch Rolling have modeled the cost and reliability impacts of Environmental Protection Agency regulations in the Midcontinent Independent Systems Operator and Southwest Power Pool. They have also evaluated the cost and reliability implications of energy policies in more than twelve states. Isaac grew up on a small family dairy farm in Wisconsin, so he cares deeply about the issues affecting rural America.



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Mitch Rolling is a Founder, and Director of Research at Always On Energy Research, where he models energy proposals, analyzes the energy industry and electricity policy, and writes about energy and environmental issues. His research has been featured in publications such as The Wall Street Journal and Forbes. Mitch and his colleague Isaac Orr co-authored an award-winning report highlighting the impact of Minnesota's 50 percent renewable energy proposal and have designed several energy models to analyze the impact of energy proposals in twelve states and Environmental Protection Agency regulations in the Midcontinental Independent System Operator (MISO) and Southwest Power Pool (SPP). Mitch graduated from the University of Minnesota in 2018 with a bachelor's degree in history, and he earned an MS in Finance and Economics at West Texas A&M University in 2022.

Authors' Note: *This report is a continuation of the work performed by authors at Always On Energy Research modeling the cost of energy portfolios in states throughout the country. Portions of this report have been repurposed and modified to reflect the modeling results of the Integrated Resource Plan proposed by Arizona Public Service.*

CONTENTS

INTRODUCTION

Arizona's largest electric utility company, Arizona Public Service (APS), is in the process of voluntarily transitioning its power grid away from reliable coal and natural gas resources to a grid with a greater dependency upon intermittent wind and solar generators. This transition is not in response to legislation passed by Arizona lawmakers or policies set by the Arizona Corporation Commission (ACC), but rather to meet the company's self-imposed Net Zero by 2050 and Environmental and Social Governance (ESG) goals.

Always On Energy Research (AOER) modeled the cost and reliability implications of the APS Preferred Plan and determined that the company's unsolicited goal to obtain 100 percent of its electricity from carbon-free sources by 2050 will have significant and negative impacts on the affordability and reliability of the APS power system.

Our analysis found that this resource mix would cost APS customers at least $42.7 billion through 2038, excluding the impact of federal subsidies, compared to operating the existing electric grid. It will also cause electricity prices to increase by at least 6.23 cents per kWh, or 45 percent. As a result, the average APS customer would see their annual electricity costs increase by at least $1,620 by 2038.

Adding insult to the injury of higher prices for consumers, the company's service territory would also be more vulnerable to rolling blackouts due to an overreliance on unreliable energy resources like wind and solar in addition to demand response (DR) and energy efficiency (EE) programs that may not materialize. Our modeling indicates that the APS Preferred Plan would only be able to keep the lights on if the utility achieves a 9-fold increase in the amount of energy efficiency currently on its system. If less energy efficiency is achieved, the APS IRP would result in multiple rolling blackout events from July 20-23, 2038, with the two largest lasting for 11 and 9 hours, respectively, due to low wind and solar output.

Instead of spending billions of dollars on an unreliable electric grid, APS could choose to meet its growing energy needs by retaining its existing coal plants and building new natural gas plants. AOER determined a coal and natural gas resource portfolio would allow APS to reliably meet the growing demand for electricity in its service territory at a lower cost. Our analysis found this scenario would cost $20.8 billion through 2038, a savings of $21.9 billion.

SECTION I:

How Perverse Profit Motives Drive APS's Green Goals

The most important thing to know about Arizona Public Service (APS) is that it is not a private company, it is a government-approved monopoly utility. This means that APS has the exclusive right to sell electricity in its service territory, and the families and businesses who live in that territory have no ability to "shop around" for another electricity provider with lower rates or better services.

Because customers have no choice but to buy their power from APS, it would be unfair to let the monopoly utility charge whatever it wishes for electricity. As a result, electricity prices are set by government regulators at the ACC using a mathematical formula called the Cost-of-Service formula.[1]

In its most basic form, the formula states that utilities like APS are allowed to charge enough for their electricity to recover the cost of providing the service to everyone in their service territories, plus a government-approved profit, **often five to ten percent,** on their capital investments.[2] As long as the expenses are approved by the regulator, utilities make a profit on every dollar they spend on new builds such as wind turbines, solar panels, natural gas plants, or even renovating corporate offices.[3]

The more money APS spends, the more money it will make for its shareholders at the expense of ratepayers.

On the other side of this equation is depreciation. Every year, the company pays off a portion of the money spent to build a plant, and the company no longer profits from this depreciated capital expense. This means APS is highly incentivized to retire older power plants that have paid off their "mortgages," even though these power plants now provide the lowest-cost, most reliable power to its customers. The incentives of the utility are the exact opposite of the families and businesses they serve.

Understanding the Cost-of-Service formula and the perverse incentives it creates are fundamental to understanding APS's desire to shutter its coal plants and replace them with an expensive combination of wind turbines, solar panels, battery storage facilities, and natural gas peaking plants.

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[1] ***Nicole Garcia,*** *"ACC Approves Policy Statement Regarding Formula Rate Plans," Arizona Corporation Commission, December 3, 2024, https://www.azcc.gov/news/home/2024/12/03/acc-approves-policy-statement-regarding-formula-rate-plans.*
[2] ***Travis Kavulla,*** *"There is No Free Market for Electricity: Can There Ever Be?" American Affairs Journal, May 20, 2017, https://americanaffairsjournal.org/2017/05/no-free-market-electricity-can-ever/.*
[3] ***Travis Kavulla,*** *"There is No Free Market for Electricity: Can There Ever Be?" American Affairs Journal, May 20, 2017, https://americanaffairsjournal.org/2017/05/no-free-market-electricity-can-ever/.*

SECTION II:

Integrated Resource Planning 101 and the APS Preferred Plan

Because government-approved monopolies, like APS, make a profit whenever they build new assets, they have a strong incentive to build as much infrastructure as possible, even if these projects are non-productive or not needed.[4] To keep these perverse incentives in check, the investment decisions made by monopoly utilities must be reviewed and approved by regulators at the ACC in a document called an Integrated Resource Plan (IRP).

An IRP is a document created by utilities explaining which types of resources they plan to utilize to meet their expected future electricity demand over a given time horizon.[5] In Arizona, these documents are produced every three years, and they cover a period of fifteen years.[6]

In theory, these plans use both supply-side resources, like building new power plants, and demand-side resources, like energy efficiency, to ensure reliable service to the utility's customers in the most cost-effective way.[7]

However, in the case of the APS IRP described below, the company relies heavily on California's price on carbon dioxide emissions and Inflation Reduction Act (IRA) subsidies to justify its Preferred Plan as "least cost." These distortions hide the true cost of the IRP and allow APS to prioritize its self-imposed Net Zero decarbonization goals over providing reliable service at the lowest possible cost to ratepayers, while generating $16.7 billion in additional profits for the utility's shareholders.

APS's Preferred Plan

In its 2023 IRP, APS evaluated fourteen different scenarios, or plans. The company's favored scenario is called the "Preferred Plan."[8]

This plan retires the existing Cholla Power Plant in April of 2025, and shutters the remaining units at the Four Corners Power Plant in 2031, removing 1,357 megawatts (MW) of reliable, affordable coal capacity from the APS system. The plan then consists of building nearly 20,000 MW of new capacity to meet electricity demand growth and APS's greenhouse gas reduction and renewable energy goals.

APS expects a substantial increase in the total amount of electricity consumed in the coming decades due to data centers, ongoing electrification efforts, and other factors. According to APS, electricity demand is projected to increase by roughly 4.7 percent annually through 2038 (See Figure 1).

The increase in electricity use will drive peak electricity demand—the maximum quantity of electricity consumed at one time— substantially higher than it is today. According to the U.S. Energy Information Administration (EIA), the average hourly electricity demand in 2023 was 3.8 gigawatts (GW), and APS documents show a peak demand of 8.1 GW. By 2038, APS projects its peak demand will hit 13.1 GW. For context, there are 1,000 MW in one GW.

[4] ***Econometrics Laboratory,*** *"The Averch-Johnson Model of Rate-of-Return Regulation," https://eml.berkeley.edu/~train/regulation/ch1.pdf.*
[5] ***Coley Girouard,*** *"Understanding IRPs: How Utilities Plan for the Future," Advanced Energy Perspectives, August 11, 2015, https://blog.advancedenergyunited.org/understanding-irps-how-utilities-plan-for-the-future.*
[6] ***Arizona Public Service,*** *"Resource Planning," Accessed January 31, 2025, https://www.aps.com/en/About/Our-Company/Doing-Business-with-Us/Resource-Planning#:~:text=Integrated%20Resource%20Plan%20(IRP),use%20to%20meet%20those%20needs.*
[7] ***Coley Girouard,*** *"Understanding IRPs: How Utilities Plan for the Future," Advanced Energy Perspectives, August 11, 2015, https://blog.advancedenergyunited.org/understanding-irps-how-utilities-plan-for-the-future.*

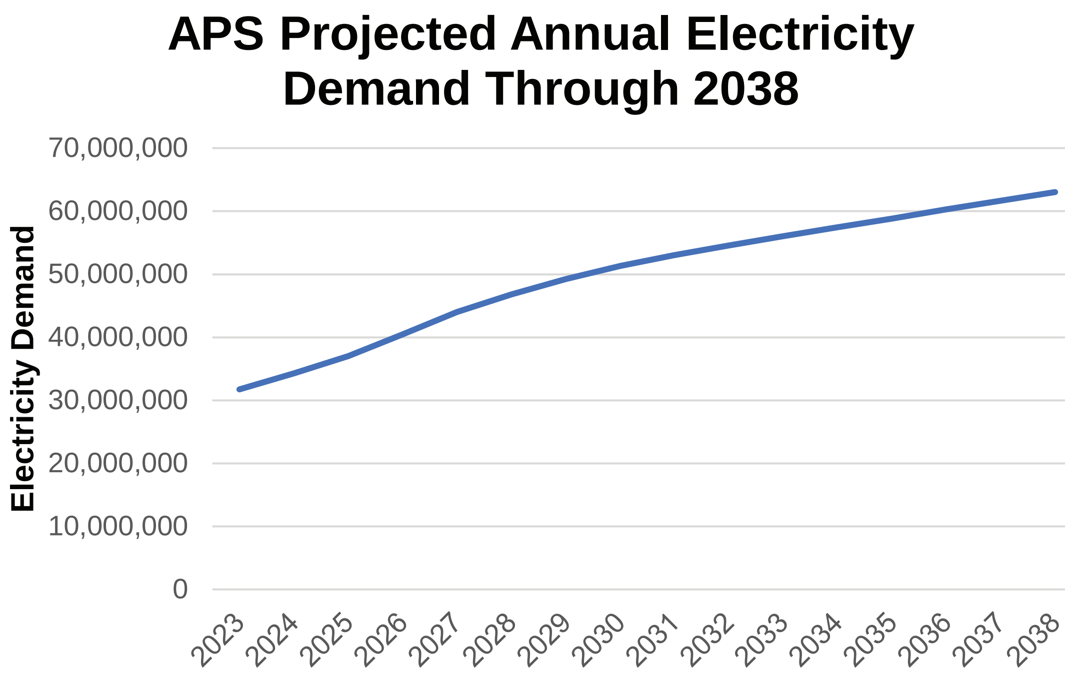

Figure 1. *APS believes its electricity demand will nearly double from 2023 through 2038.*

Meeting these new peak electricity demands, along with replacing retiring coal and gas power plants, will require a substantial increase in the amount of power plant capacity on the APS power system. As indicated in the APS planning documents, the Preferred Plan nearly triples the amount of total installed capacity on its system to meet a 60 percent increase in peak demand.[9]

Figure 2 shows the annual change in the installed capacity of the APS system. Older coal and natural gas facilities are retired in accordance with APS announcements or when the assets reach the end of their book lives. From 2023 to 2038, wind capacity grows from 637 MW to 3,100 MW, solar grows from 784 MW to 5,900 MW, battery storage grows from 300 MW to 4,100 MW, microgrids grow from 42 MW to 820 MW, distributed generation increases from 100 MW to 2,600 MW, while demand response and energy efficiency grow from 360 MW to 2,800 MW by 2038.[10]

The black line shows that during this time, the company's expected peak demand rises from 8.1 GW in 2023 to 13.1 GW in 2038, before accounting for energy efficiency and other power-saving options. Peak demand rises substantially due to the addition of datacenters, new manufacturing industries, and electric vehicle charging.

It is worth noting that the peak demand currently exceeds the amount of dispatchable coal, nuclear, and natural gas power plants on the APS system, as APS can only meet 92 percent of peak demand with thermal resources. By 2038, this will decrease to as low as 60 percent, meaning the utility will be even more dependent upon contributions from wind, solar, battery storage, and energy efficiency to keep the lights on.

[8] ***Arizona Public Service,*** *"2023 Integrated Resource Plan, Public," November 2023, https://www.aps.com/-/media/APS/APSCOM-PDFs/About/Our-Company/Doing-business-with-us/Resource-Planning-and-Management/APS_IRP_2023_PUBLIC.pdf?la=en&hash=F601897086C6836F7FD33C5C2F295F47.*
[9] ***Arizona Public Service,*** *"2023 Integrated Resource Plan, Public," November 2023, https://www.aps.com/-/media/APS/APSCOM-PDFs/About/Our-Company/Doing-business-with-us/Resource-Planning-and-Management/APS_IRP_2023_PUBLIC.pdf?la=en&hash=F601897086C6836F7FD33C5C2F295F47.*
[10] ***See Plant Retirement Schedules in the Appendix.***

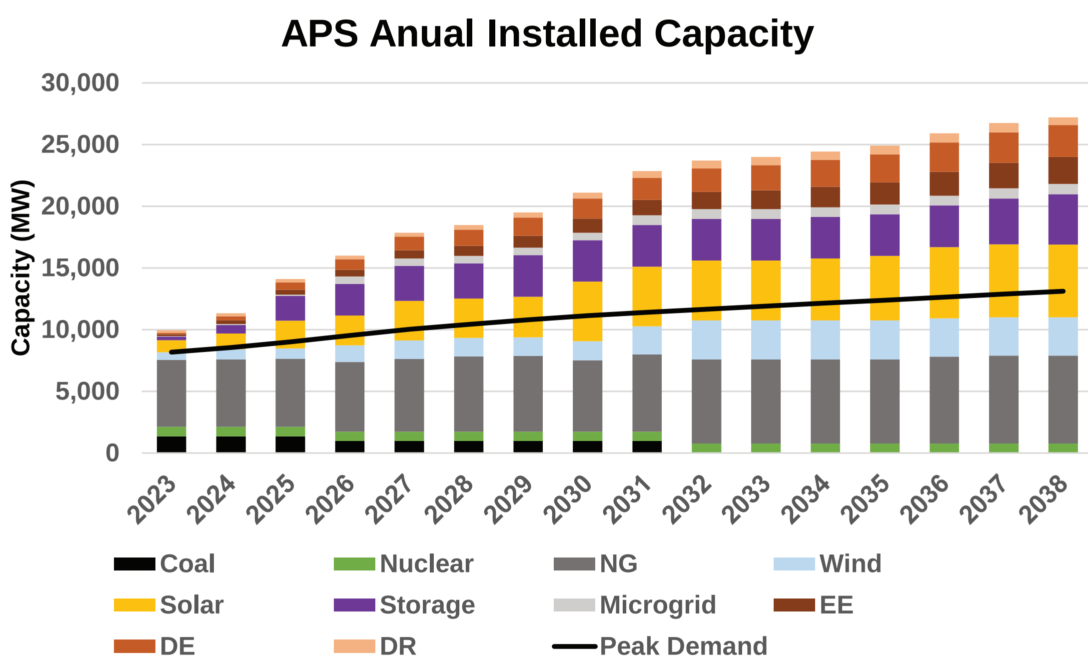

Figure 2. *Coal is phased out by 2031 and is replaced by a small increase in natural gas capacity. However, APS is growing increasingly dependent upon wind, solar, battery storage, and energy efficiency to meet its projected peak demand, rather than relying on dispatchable, long duration fuel-based assets.*

What is Energy Efficiency?

While most Arizonans are probably familiar with solar panels and wind turbines, fewer people likely understand which resource constitute energy efficiency and demand response in the APS planning documents.

For residential customers, these programs frequently take the form of allowing the utility company to control household devices and appliances like thermostats, air conditioners, water heaters, and pool pumps in exchange for up to a $50 annual bill reduction.[11]

In the future, APS believes these programs could also include having the company control when electric vehicles can be charged and potentially draining the batteries of charged cars during periods of high electricity demand and low supply from intermittent sources. This transfer of power from EVs to the grid is frequently called vehicle to grid (V2G).

According to an analysis prepared for APS by Guidehouse, energy efficiency and demand response measures for commercial and industrial customers will consist of controlling heating, ventilation, and cooling (HVAC) equipment, refrigeration control, advanced lighting control, and may also consist of larger facilities using backup power generators during periods of high demand to help reduce demand on the overall system.

[11] ***Guidehouse,*** *"2023 Energy Efficiency and Demand Response Potential Study," October 25, 2023, https://www.aps.com/-/media/APS/APSCOM-PDFs/About/Our-Company/Doing-business-with-us/Resource-Planning-and-Management/APS_IRP_2023_PUBLIC.pdf?la=en&hash=F601897086C6836F7FD33C5C2F295F4.*

SECTION III:

Impacts on APS Energy Production

The Preferred Plan filed by APS in its IRP will have a significant impact on the way the utility produces electricity for its customers.

According to APS documents, natural gas fired power plants were the largest source of electricity for the company in 2023, producing 36 percent of the electricity generated that year. Nuclear accounted for 26 percent of generation, coal provided 20 percent, 9 percent was generated from solar, 4 percent from wind, 4 percent from "other," and battery storage constituted 1 percent of the region's electricity supply, respectively (See Figure 3).

This resource mix will change substantially under the APS Preferred Plan. Figure 4 shows the APS generation mix in 2038 at the conclusion of the 2023 IRP planning period. In 2038, the energy mix will consist of 33 percent natural gas, 30 percent solar, 16 percent nuclear, 15 percent wind, 4 percent battery storage, and 2 percent other.

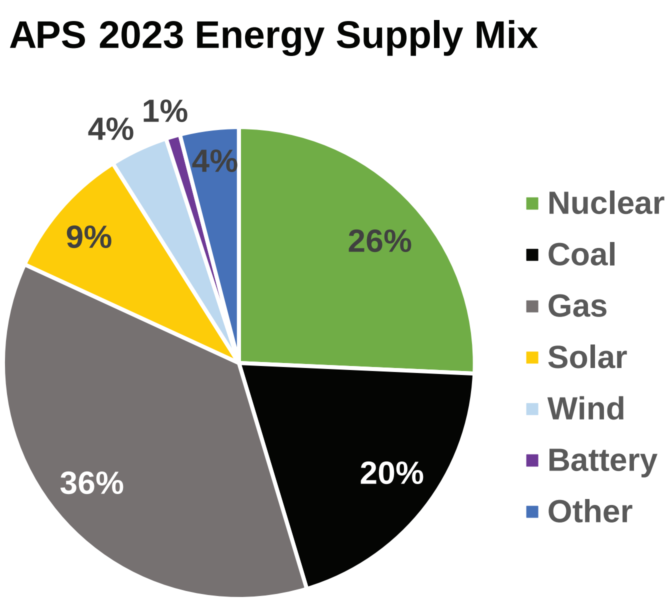

Figure 3. *Natural gas and nuclear power produce the largest share of electricity in APS, followed by coal and solar power.*

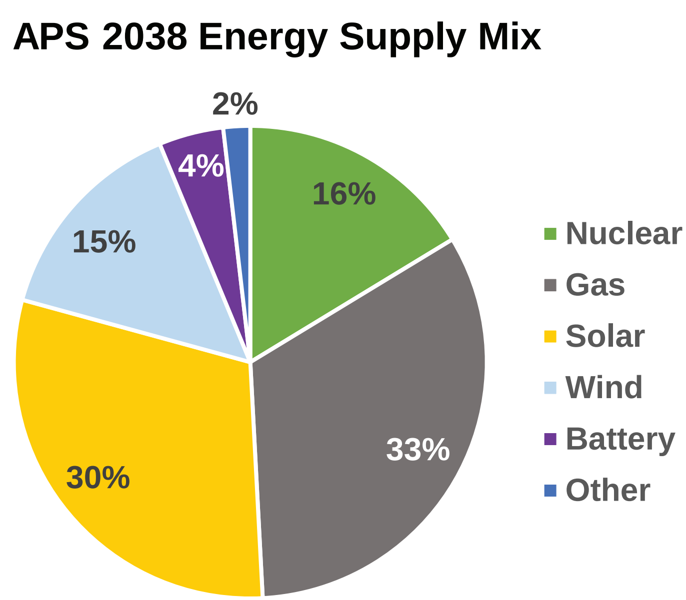

Figure 4. *Natural gas and solar become the largest sources of electricity for APS in 2038.*

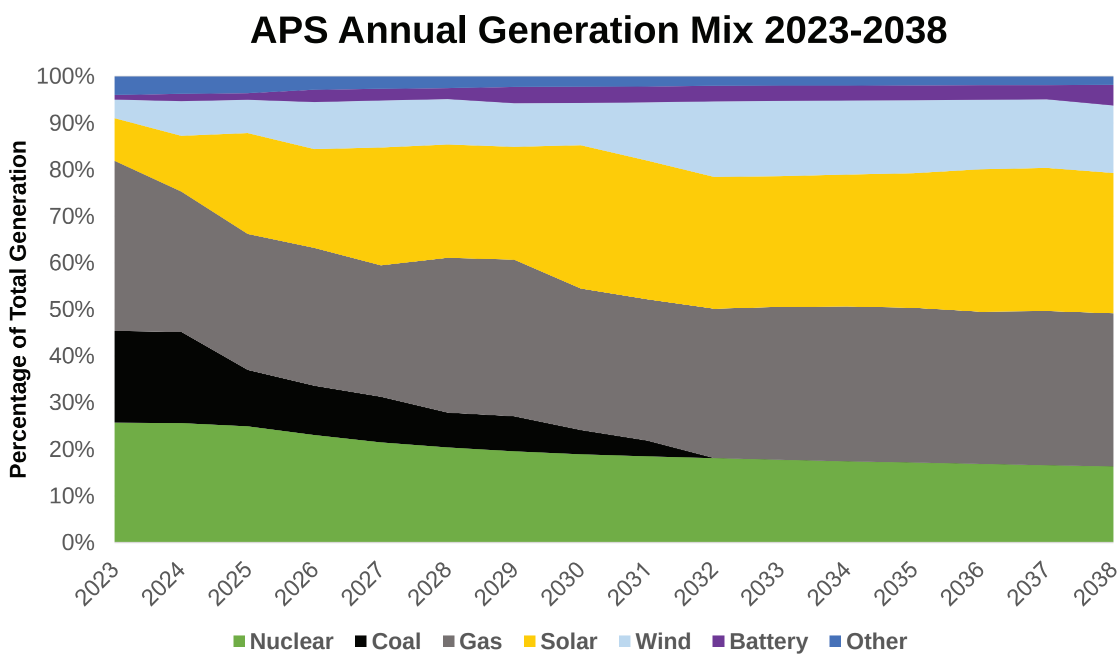

Figure 5. *By 2038, APS utilizes mostly natural gas, solar, nuclear, and wind power to power the grid, with battery storage acting as a load balancing resource to back up the intermittency of wind and solar.*

Figure 5 shows the change in electricity generation over time. Coal generation declines as the Four Corners Generating Station is shut down and the company builds more solar and wind facilities.

APS will continue to obtain the same amount of electricity from its Palo Verde nuclear plant throughout the model run, but because overall electricity generation increases on the APS system, the relative contribution of the plant to meeting the total electricity needs of the company shrinks over time.

Calculating the Cost of the APS IRP

In 2023, APS residential electricity prices were slightly lower than the national average. However, these prices would rise significantly due to the APS Preferred Plan.

Our modeling indicates that complying with the APS IRP will cost at least an additional $42.7 billion (in constant 2025 dollars) compared to operating the current electric grid without the inclusion of federal subsidies. This would raise all-sectors electricity rates from 13.83 cents per kilowatt hour (kWh) in 2023 to 20.05 cents per kWh in 2038 – an increase of 6.22 cents per kWh.

As a result, the average annual electricity cost for each APS utility customer would increase by $1,620 in 2038, the equivalent of paying an additional $135 per month (see Figure 6).

Figure 6 shows the average additional cost of complying with the APS IRP from 2023 through 2038, compared to the current cost of electricity. This number is obtained by dividing the annual cost of the IRP among all APS utility customers, including residential, commercial, and industrial electricity users. The APS IRP immediately increases electricity costs as wind, solar, battery storage, and transmission projects are built.

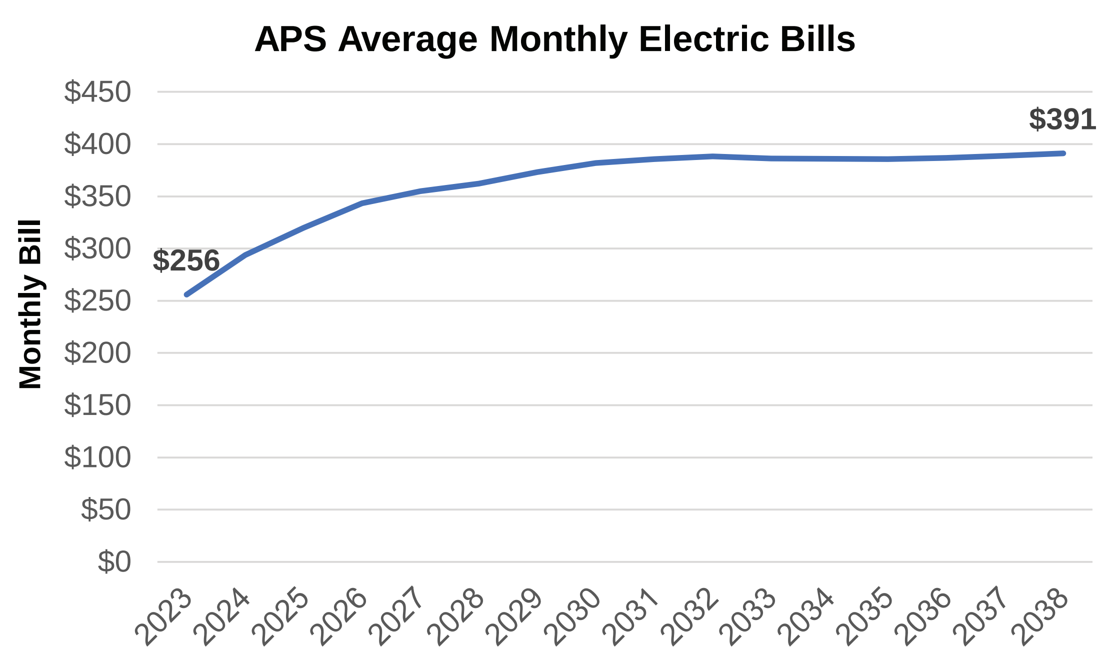

Figure 6. *Annual costs for APS customers increase by $1,620 annually and $135 monthly.*

Residential Customers

Under the APS IRP, residential electricity prices would increase significantly by 2038, causing APS families to see their annual electricity costs increase by $1,150 in that year. This would cause the average monthly bill to rise from $155 in 2023 to $251 in 2038, an increase of $96 per month (see Figure 7).

Commercial Customers

Under the APS IRP, commercial customers like small businesses, grocery stores, and other retailers would see their annual electricity costs increase by $5,453 by 2038, a monthly increase of $454 compared to 2023 costs (see Figure 8). These higher electricity costs would likely be passed on to consumers in the form of higher prices for goods and services.

Industrial Customers

Under the APS IRP, electricity costs for large industrial companies in the area would increase by $55,710 annually by 2038, or $4,640 per month. (see Figure 9). Compliance costs for APS's IRP are driven by the need to build enough wind turbines, solar panels, battery storage facilities, natural gas peaking plants, and transmission lines to meet growing electricity demand and satisfy the company's emissions reduction and renewable energy goals.

Other factors driving cost increases include additional taxes on newly-constructed infrastructure and profits for APS as the company earns a rate of return on new generation assets.

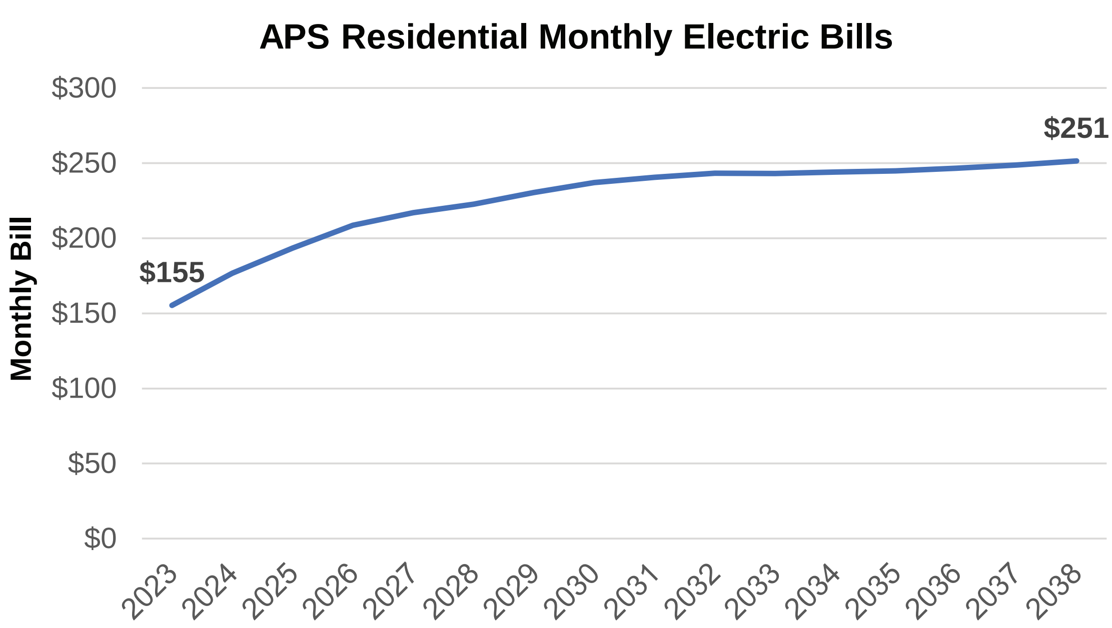

Figure 7. *APS families would see their electric bills increase by an average of $1,150 per year, or $96 monthly.*

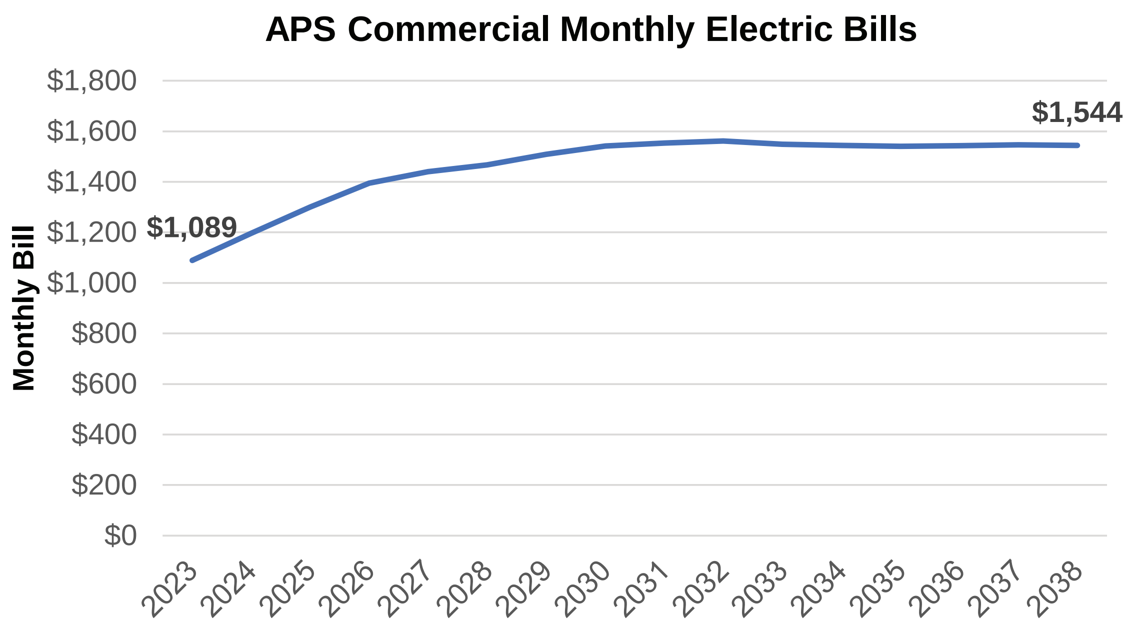

Figure 8. *Costs for commercial customers, such as small businesses, rise quickly, peaking at $1,543 per month in 2038.*

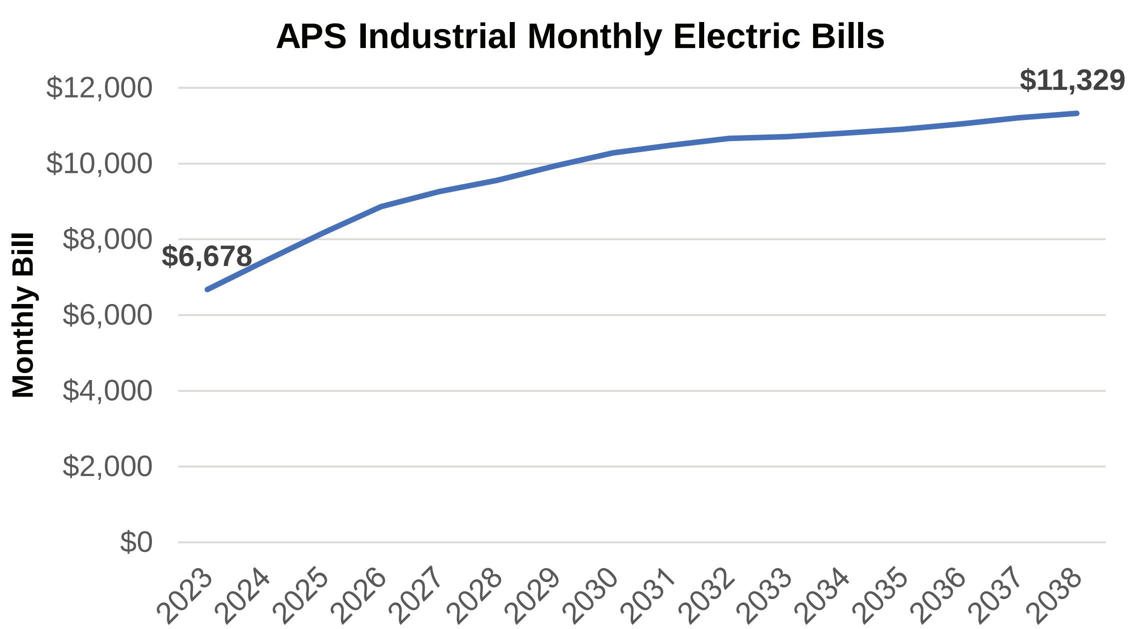

Figure 9. *Industrial electricity consumers would experience cost increases of $55,710 by 2038 under the APS IRP.*

SECTION V:

How Wind, Solar, and Battery Storage Facilities Drive up Costs Compared to Reliable Power Plants

Thus far, this report has summarized the cost difference between the APS IRP and using APS's existing power plants. In this section, we will discuss how attempting to run a reliable electric grid using a growing amount of wind, solar, and battery storage drives up costs to a much greater extent than operating a grid with coal, natural gas, or nuclear power plants.

The most important thing to know about the electric grid is that the supply of electricity must be in perfect balance with demand at every second of every day. If demand rises as Arizonans turn on their air conditioners or charge their electric vehicles, an electric company must increase the supply of power to meet that demand. If companies are unable to increase supply to meet demand, grid operators are forced to cut power to consumers —i.e. initiate brownouts or blackouts — to keep the entire grid from crashing.

Generating more electricity is relatively easy with dispatchable power plants—plants that can be turned up or down on command—like those powered with coal, natural gas, nuclear fuel, or hydroelectric plants. But adjusting to second-by-second fluctuations in electricity demand is much more difficult with wind and solar, whose electricity production is subject to second-by-second fluctuations in the weather. As a result, it is much more difficult to provide reliable power as regions become more reliant upon wind and solar to meet their energy needs.

It is possible to mitigate some of the inherent unreliability of wind and solar by building battery storage facilities and natural gas peaking plants, in addition to expanding transmission line capacity. It is also possible to mitigate the intermittency of wind and solar by vastly increasing the amount of wind and solar capacity on the grid (known as "overbuilding" wind and solar installations) to allow electricity demand to be met even on cloudy or low-wind days, and curtailing, or turning off, much of this capacity when wind and solar production is higher.

Each of these mitigation strategies, however, are imperfect, inefficient, and result in additional costs to the entire electric system. These costs include higher utility profits, taxes, and other integration expenses for building transmission lines, batteries, natural gas peaking plants, and additional wind and solar capacity. Each of these additional costs will be discussed in greater detail below.

Increasing Electricity Generation Capacity

Building and operating new power plants is expensive. The APS IRP would greatly increase the amount of new power plant capacity on the APS electric grid, which is why it is so costly.

Under the APS IRP, the amount of installed power plant capacity on APS system would increase from 10 GW in 2023 to over 26 GW by 2038. This means the APS IRP would require nearly 2.7 times more power plant capacity than is currently used to meet APS's electricity demand (see Figure 10) and would build roughly 8.2 MW of renewable and storage capacity for every 1 MW of coal capacity retired.

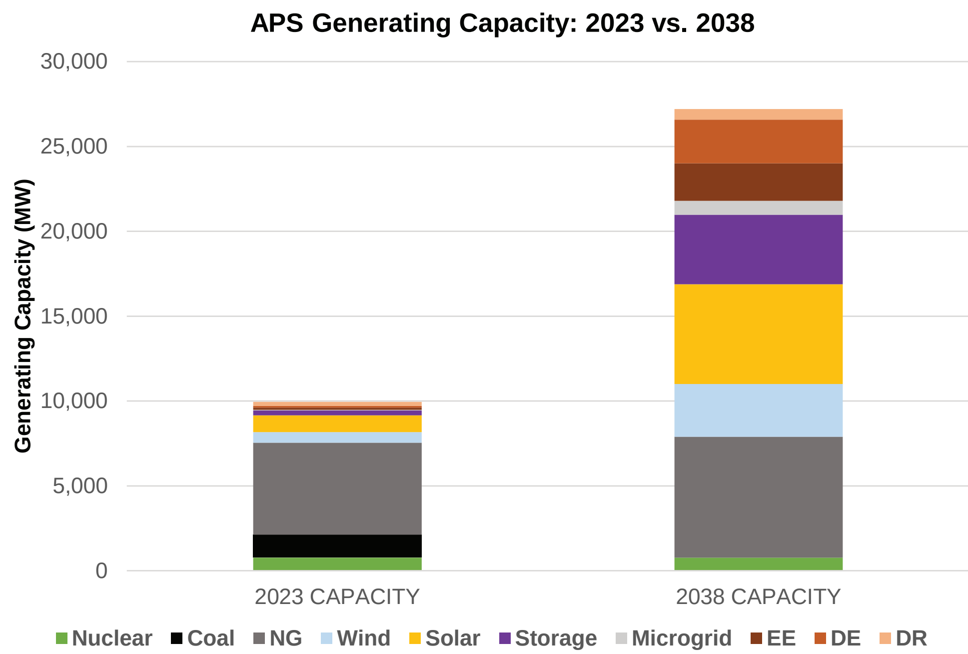

Figure 10. *Complying with the APS IRP would require almost 3 times more installed capacity on the APS electric grid to maintain a reliable system, based on the APS IRP. This massive buildout of capacity would drive significant cost increases for families and businesses. NG denotes natural gas, EE is energy efficiency, DE is distributed energy resources like rooftop solar, and DR is demand response.*

While adding power plant capacity to the grid may sound like a good thing, increasing capacity merely to meet the utility's green energy goals rather than meeting electricity demand is an unnecessary cost that will harm APS families and the region's economy.

By 2038, wind capacity grows to 3.3 GW, solar capacity increases to 5.9 GW (including solar plus storage facilities), and battery storage would rise to 4.1 GW with four hours of storage per GW (See Figure 10).

A portion of the extra wind and solar power must be used to charge the batteries. Once the batteries are fully charged, any additional solar or wind power generated is curtailed, or turned off. Curtailment is expected to become increasingly common for APS and the nation as a whole as more wind and solar facilities are placed into service on the grid.[12]

Building these solar panels, solar plus storage facilities, wind turbines, battery storage facilities, and natural gas peaking plants would cost $5.1 billion, $7.3 billion, $4.4 billion, $7.6 billion, and $1.5 billion respectively.

Transmission Costs

Transmission lines are important: It does no good to generate electricity if it cannot be transported to the homes and businesses that rely upon it. Transmission costs are driven by the need to build new infrastructure to connect APS to wind turbines and solar panels that are located farther away from population centers than traditional thermal power facilities.

The additional costs of transmission lines for the APS IRP are proprietary but were included in our modeling.

Utility Profits

APS is a regulated monopoly utility company and is entitled to recover the cost of providing service to ratepayers with a government-

[12] ***National Renewable Energy Laboratory,*** *"The Curtailment Paradox in a High Solar Future," U.S. Department of Energy, accessed October 6, 2021, https://bit.ly/2ZT4JMu.*

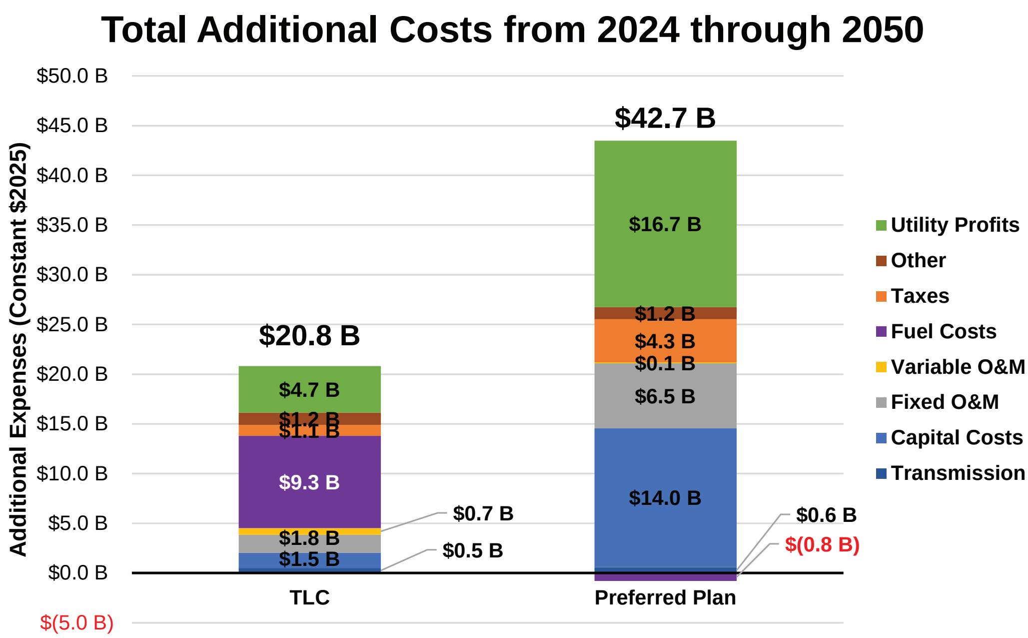

Figure 11. *The total additional cost would be $42.7 billion through 2038.*

approved return on investment. This means that for every dollar APS spends building new infrastructure, it is allowed to recover a rate of return from ratepayers, as long as the expenses are approved by the ACC.

Utility profits are a major driver of additional expenses arising from the APS IRP. Because the company is building so much new capacity, utility profits are expected to grow substantially through 2038. Based on the capacity additions within the APS IRP, our modeling indicates the utility would make an additional $16.7 billion through 2038.

Additional Property, State, and Federal Taxes

Property taxes increase under the APS IRP because compared to the current grid, there is much more property to tax. While the property taxes assessed on power plants are often a crucial revenue stream for local communities that host power plants, these taxes also effectively increase the cost of producing and providing electricity for everyone.

Summary of Total Additional Costs Compared to Current Grid

While APS will experience modest declines in fuel expenditures through 2038 of over $620 million through the model run, these savings are far outweighed by the additional capital costs, fixed operations and maintenance costs, taxes, and profits. These costs result in a net expenditure of $42.7 billion through 2038 (See Figure 11).

It is important for readers to understand that this cost estimate reflects the cost of the proposed generation capacity built by APS in its Preferred Plan. However, as we discuss in our sensitivity analyses in Section VII: Implications for Reliability, the Preferred Plan cannot reliably meet electricity demand for all hours of the study period in scenarios where less energy efficiency is available to the utility.

Unfortunately, energy efficiency is often used by wind and solar special interest groups and utilities to manipulate their models by unrealistically reducing the amount of electricity generating capacity needed to meet peak demand. As a result, the true costs of the Preferred Plan are underestimated. Reliably meeting electricity demand in the future will be even more expensive than the figures here suggest if the assumed amount of energy efficiency in the Preferred Plan does not materialize.

SECTION VI:

The Levelized Cost of Energy for Different Generating Resources

Almost all studies that examine the cost of renewable energy use a methodology called the Levelized Cost of Energy, or LCOE, to assess the cost of wind, solar, and batteries compared to different technologies.[13] LCOE estimates reflect the cost of generating electricity from different types of power plants, on a per-unit of electricity basis (generally megawatt hours), over an assumed lifetime and quantity of electricity generated by the plant.

In other words, LCOE estimates are essentially like calculating the cost of your car on a per-mile-driven basis after accounting for expenses like initial capital investment, loan and insurance payments, fuel costs, and maintenance.

Wind and solar advocates often misquote LCOE estimates from Lazard or EIA to claim that wind and solar are now lower cost than other sources of energy. However, Lazard and EIA show the cost of operating a single wind or solar facility at its maximum reasonable output; they do not convey the cost of reliably operating an entire electricity system with high penetrations of wind and solar, which costs exponentially more.

Even more importantly, the LCOE estimates generated by Lazard and EIA do not account for battery storage, natural gas peaking plants, or the overbuilding and curtailment that must occur to ensure that grids with growing reliance on wind and solar can meet electricity demand.

It is important for the reader to understand that the costs associated with battery storage, gas peaking plants, and overbuilding and curtailment increase dramatically because the amount of wind, solar, and battery storage must be "overbuilt" to account for the intermittency of wind and solar, which is why the APS IRP requires an installed capacity of 26 GW to meet the projected peak demand of 13 GW.

AOER's model accounts for all of these additional expenses and attributes them to the cost of wind and solar to get an "Always On" LCOE estimate for the cost of serving load with various energy sources. Our Always On LCOE represents the cost of delivering the same reliability value of other generating technologies, allowing for an apples-to-apples comparison of the cost of reliably meeting electricity demand with existing nuclear, natural gas, and coal plants operating in APS, with new plants built under the APS IRP.

The cost of existing coal, natural gas, and nuclear generators was estimated using historical FERC Form 1 filings for APS generators. Existing coal, combined cycle gas, combustion turbine gas, and nuclear cost $58, $42, $100, and $28 per MWh, respectively, in 2023.

Under the APS IRP, these low-cost, reliable plants are no longer prioritized for future load growth, and some are replaced with wind, solar, and battery storage. Figure 12 shows the Always On LCOE of wind, solar, and solar plus storage facilities reaches approximately $157, $148 and $181 per MWh, respectively, in 2038.

[13] ***Isaac Orr and Mitch Rolling,*** *"Renewables Blueprint," Center of the American Experiment, March 2021, https://files.americanexperiment.org/wp-content/uploads/2021/06/Renewable-Energy.pdf.*

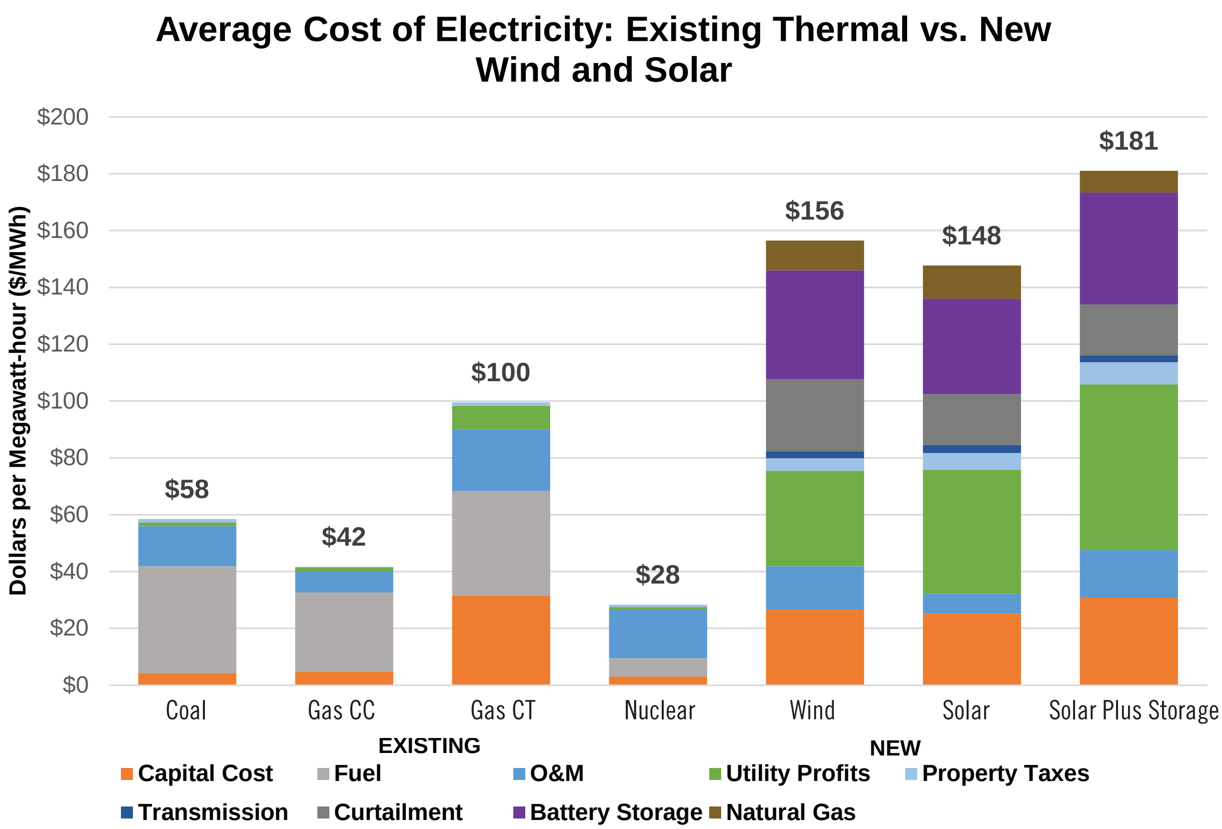

Figure 12. New solar plus storage facilities are the most expensive form of new electricity generation built under the APS IRP. Once costs such as state taxes, transmission, utility returns, battery storage, and overbuilding and curtailment are accounted for new wind costs $157 per MWh, new solar costs $148 per MWh, and new solar plus storage costs $181 per MWh.

Because curtailment rates reach 19 percent by 2038, overbuilding, curtailment, and battery storage costs - which are hidden costs required to maintain grid reliability with intermittent resources - are significant drivers of the cost of wind and solar due to the need to build twice as much capacity as would be needed to meet peak demand with dispatchable power plants. As a result, the cost of battery storage, peaking plants, overbuilding, and curtailing in Figure 12 can be thought of as a levelized cost of intermittency, or unreliability.

Costs are higher for wind and solar facilities because grids powered with large concentrations of intermittent wind and solar resources require much more total capacity and transmission to meet electricity demand than systems consisting largely of dispatchable power systems such as traditional fossil fuel and nuclear plants.

These costs are based on APS energy mix as laid out in the IRP. However, AOER's model demonstrates the resource mix in the APS IRP may be inadequate to maintain reliability for historical load profiles depending on the amount of energy efficiency that is placed into service.

Implications for Reliability

Reliability is the most crucial function of the electric grid. Our lives have never been more dependent upon electronic devices, and it is highly unlikely that we will be less dependent upon them in the future.

The APS IRP relies heavily on wind, solar, battery storage, and energy efficiency, which has the potential to undermine the reliability of the electric grid by making it more dependent on fluctuations in the weather, potentially leading to capacity shortfalls (i.e. blackouts) in the future.

AOER's reliability modeling used historical load profiles and hourly wind and solar capacity factors from 2019 to 2023 to assess whether the resource mix in the APS IRP could maintain reliability in the future. The thought process here is simple and straightforward: If the APS Preferred Plan cannot maintain reliability based on past wind and solar performance within the APS footprint, we should have little confidence in its ability to do so in the future.

In AOER's modeling, electricity demand for each historical load profile year was extrapolated to meet the 2038 demand and energy use projections from APS.

Figure 13 shows electricity demand and supply by type for a hypothetical period in the future stretching from July 21, 2038, through July 23, 2038. As you can see, wind, solar, battery storage, nuclear, and natural gas power plants, and energy efficiency are able to meet electricity demand, shown in the black line, despite a wind drought impacting wind generation.

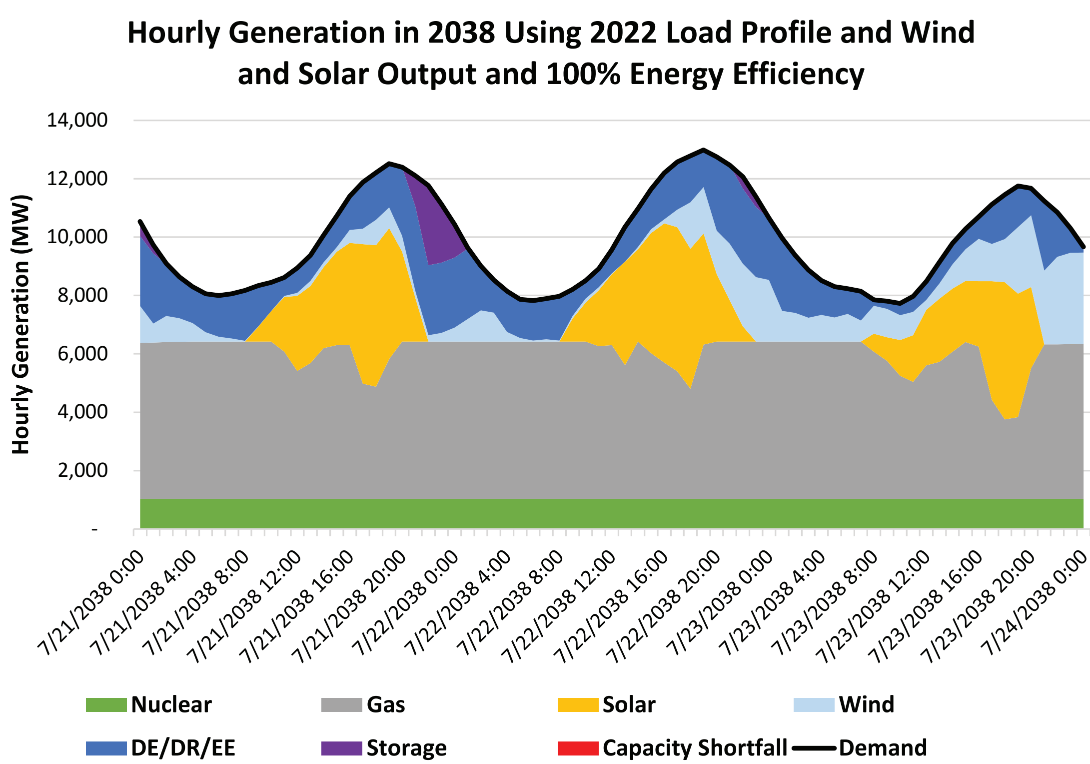

Figure 13. *The system is kept reliable because large amounts of energy efficiency reduce electricity demand on the system.*

However, the reliability of the grid during this stretch is reliant upon APS meeting its target of 1,697 MW of energy efficiency, shown in dark blue in the graph. If the company fails to reach this level of energy efficiency, the system will not be able to reliably meet demand.

According to Attachment C.1 (A): Coincident Peak Demand By Month And Customer Class, APS had 147 MW of energy efficiency available to meet peak demand in 2023, which is just 8.6 percent of the capacity it is relying on to meet demand in 2038. These energy efficiency numbers differ slightly from the 183 MW estimated to be available in 2023 in the Guidehouse study. AOER's modeling uses the APS figures from Attachment C.1 (A) for this portion of the analysis.

AOER believes there is considerable uncertainty in the energy efficiency capacity assumed in the APS IRP because the Guidehouse study indicates that not all of the energy efficiency capacity assumed in the IRP is cost effective. There is also considerable uncertainty in the adoption of cost-effective measures, such as smart devices and direct load control (DLC) for residential customers, because these energy efficiency gains would be contingent upon customers greatly increasing their enrollment in programs like the AC Rewards Program.

Therefore, AOER modeled two sensitivity analyses that incorporate less energy efficiency into the capacity stack in the coming years, one scenario that assumes 50 percent of the potential energy efficiency is achieved, and another scenario where 25 percent is achieved.

In the 50 percent scenario, the APS system would have access to 848.5 MW of energy efficiency resources. Extrapolating historical load profiles to meet 2038 peak demands and using historical wind and solar capacity factors for the region from 2019 through 2023 show that there would be insufficient capacity to meet demand stretching from July 22, 2038, through July 23, 2038 (See Figure 14).

The large capacity shortfall on July 23rd is caused by low wind output and insufficient battery storage capacity to store excess renewable generation from previous days. During this period, APS's wind turbines averaged just 11 percent of their potential output.

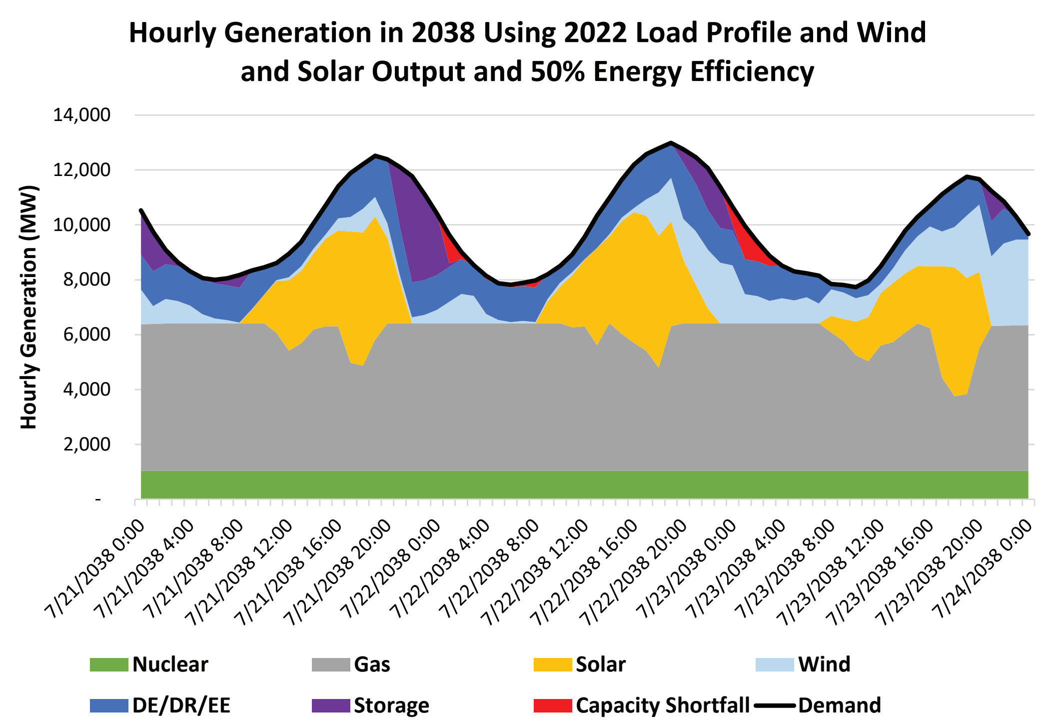

Figure 14. The resources on the APS grid under the APS Preferred Plan are unable to meet electricity demand for every hour of the year, resulting in multiple capacity shortfalls. The shortfalls occur as the batteries are unable to recharge due to an ongoing wind drought. The blackouts occur on July 22nd and 23rd, with the largest lasting for 5 hours after the sun sets and the batteries run out of stored power.

The size of the shortfall is significant, with a maximum shortfall of 1,217 MW occurring at 1:00 A.M. on July 23, 2038, after the sun sets and there is no more storage to back up the wind and solar fleet. This shortfall constitutes 12 percent of the total demand during this time period, meaning thousands of families and businesses would be without power.

In the 25 percent scenario, the APS system would have access to 424.25 MW of energy efficiency resources. Extrapolating historical load profiles to meet 2038 peak demands and using historical wind and solar capacity factors for the region from 2019 through 2023 show that there would be insufficient capacity to meet demand stretching from July 20, 2038, through July 23, 2038 (See Figure 15).

The size of the shortfalls is more significant in this scenario, with a maximum shortfall of 3,701 MW occurring at 11:00 P.M. on July 21, 2038, after the sun sets and there is no more storage to back up the wind and solar fleet. This shortfall constitutes 33 percent of the total demand during this time period, meaning hundreds of thousands of families and businesses would be without power.

Energy efficiency can be a helpful tool for reducing electricity demand during periods of high stress on the system, but there is considerably more uncertainty surrounding the adoption of energy efficiency measures than in building supply-side resources.

Rectifying the potential unreliability of the APS IRP under these energy efficiency sensitivities would require additional generating capacity, which would increase the costs associated with the Preferred Plan. If this additional capacity is in the form of wind turbines, solar panels, and battery storage facilities, the costs could be significant, and the grid would still be dependent on fluctuations in weather conditions.

It is for this reason that AOER believes the best way to ensure a low cost, reliable grid in the future is to have enough dispatchable power plants on the system to meet peak demand, plus a margin of safety, as we discuss in the True Lowest Cost (TLC) scenario in Section IX.

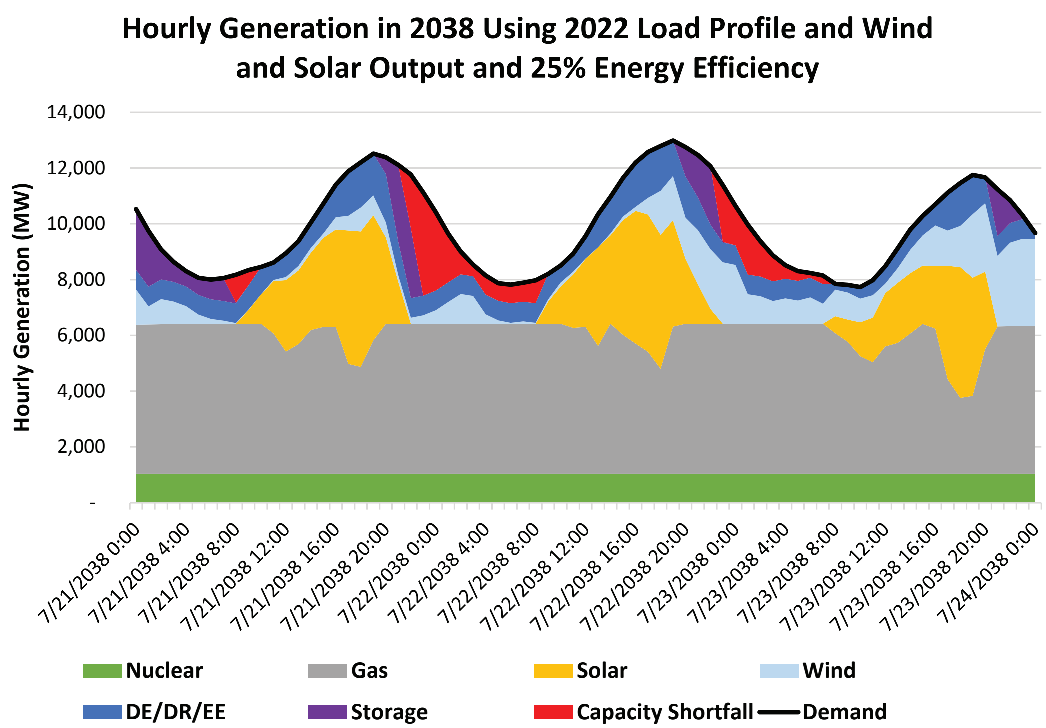

Figure 15. *The resources on the APS under the APS Preferred Plan are unable to meet electricity demand for every hour of the year, resulting in multiple capacity shortfall events as the batteries are unable to recharge due to an ongoing wind drought. The multiple shortfall events occur on consecutive days from July 21-23, with the two largest lasting for 11 and 9 hours.*

Emissions Reductions

When evaluating energy policies aimed at reducing greenhouse gas emissions, it is important to weigh the cost of reducing emissions against the expected benefits of doing so. If the costs of reducing emissions exceed the expected benefits, the policy does not make sense to enact.

To conduct this cost benefit analysis, policymakers often use a tool called the Social Cost of Carbon (SCC) to estimate the economic costs, or damages, of emitting one additional ton of carbon dioxide into the atmosphere.[14] APS did not use the SCC in its IRP planning, instead opting to use carbon costs based on the actual trading price of CO2 allowances in the California wholesale energy market.

Figure 16 shows the annual decline in carbon dioxide emissions from the power sector under the APS Preferred Plan.

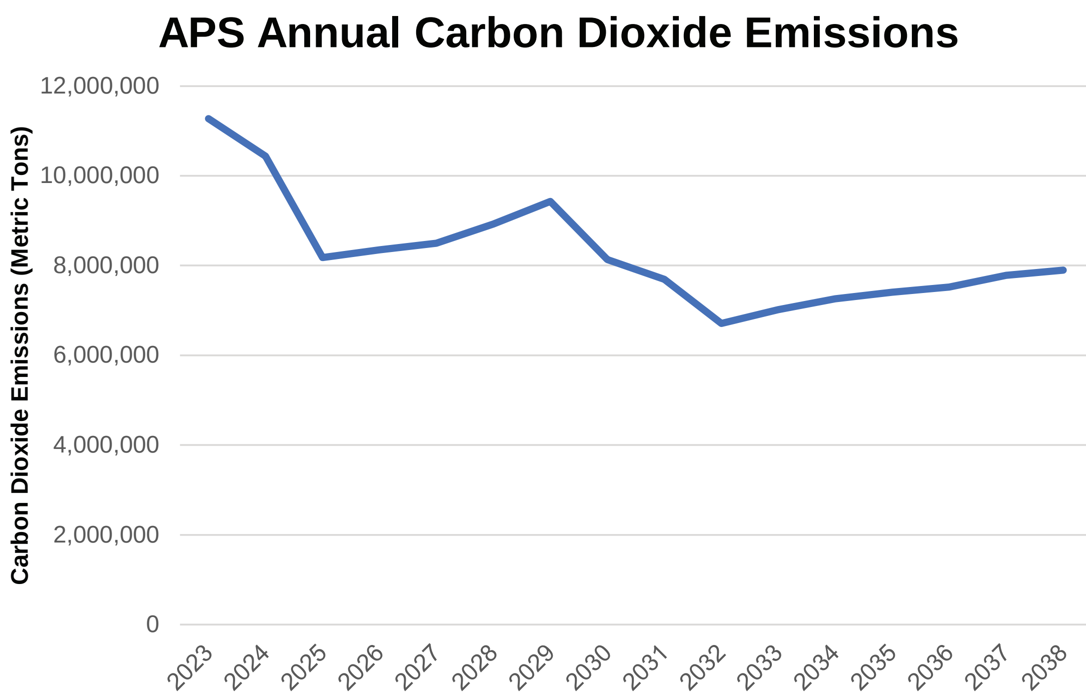

Figure 16. *Under the APS Preferred Plan, carbon dioxide emissions would drop 30 percent from 2023 levels to 7.9 million metric tons by 2038. Emissions rise after 2032 in response to rising electricity demand.*

[14] ***Kevin Rennert et al.,*** *"The Social Cost of Carbon," The Brookings Institute, September 8, 2021, https://www.brookings.edu/bpea-articles/the-social-cost-of-carbon/#:~:text=The%20social%20cost%20of%20carbon%20is%20an%20estimate%20of%20the,the%20United%20States%20and%20abroad.*

Figure 17 shows the cost of reducing each ton of carbon dioxide each year under the APS Preferred Plan and compares it to the carbon cost estimates provided in the APS IRP. The green bars exceed the black line in each of the years examined, meaning the cost of reducing carbon dioxide emissions under the Preferred Plan far exceeds the benefits of doing so.

In short, APS is imposing a net harm on its ratepayers after accounting for the impacts of climate change. Even after accounting for the cost of carbon dioxide emissions, Arizona families and businesses would benefit more from a grid that utilizes the existing coal units through the end of their useful lifetime and new combined cycle natural gas plants to meet the growing energy needs of APS customers.

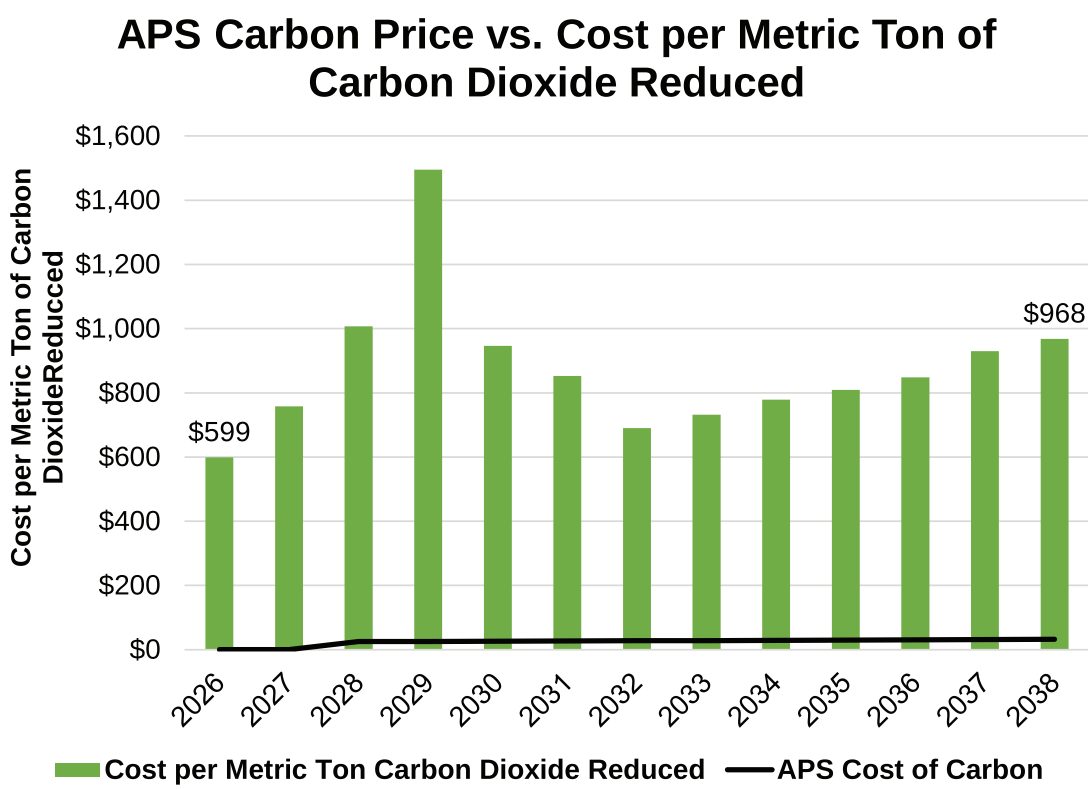

Figure 17. *The cost of reducing emissions under the APS IRP vastly exceed the benefits of reducing emissions.*

SECTION IX:

What if the APS IRP Was Designed to Meet Demand Instead of Their Green Goals?

Thus far, this report has described the Preferred Plan scenario of the APS IRP to meet the region's growing electricity demand and the company's renewable energy and carbon dioxide reduction goals. However, the company's claims that the Preferred Plan is the least cost resource portfolio are predicated on the inclusion of a carbon tax (or similar policy) and IRA subsidies. Without these two factors affecting the modeling, the Preferred Plan would not be least cost for APS customers.

AOER conducted modeling on an alternative scenario, referred to as the True Least Cost (TLC) scenario, and concluded APS customers would benefit most from continuing to operate the Four Corners coal plant and building new combined-cycle natural gas plants to reliably meet rising customer demand, rather than relying on a substantial buildout of wind, solar, and battery storage capacity.

Figure 18 shows the installed capacity of the current grid and compares it to the total installed capacity of the TLC scenario and the APS Preferred Plan. The TLC scenario is able to meet the projected peak demand of 13.1 GW with only 18.2 GW of installed capacity, whereas the Preferred Plan requires 27 GW to meet the same peak demand.

Under the TLC scenario, nuclear capacity remains the same as 2023, coal capacity falls from 1,357 MW to 960 MW, natural gas capacity increases from 5.2 GW to 10.7 GW, and solar and wind capacity falls slightly as facilities reach the end of their useful life. Energy efficiency and demand response remain small portions of the electric grid, but distributed energy resources like rooftop solar are assumed to be the same as the Preferred Plan for APS in 2038.

Because the TLC scenario builds far less capacity to meet the energy needs of APS customers, it is a lower cost portfolio. Figure 19 compares the costs of the TLC scenario and Preferred Plan through 2038. The TLC scenario costs $20.8 billion, compared to the Preferred Plan, which costs $42.7 billion.

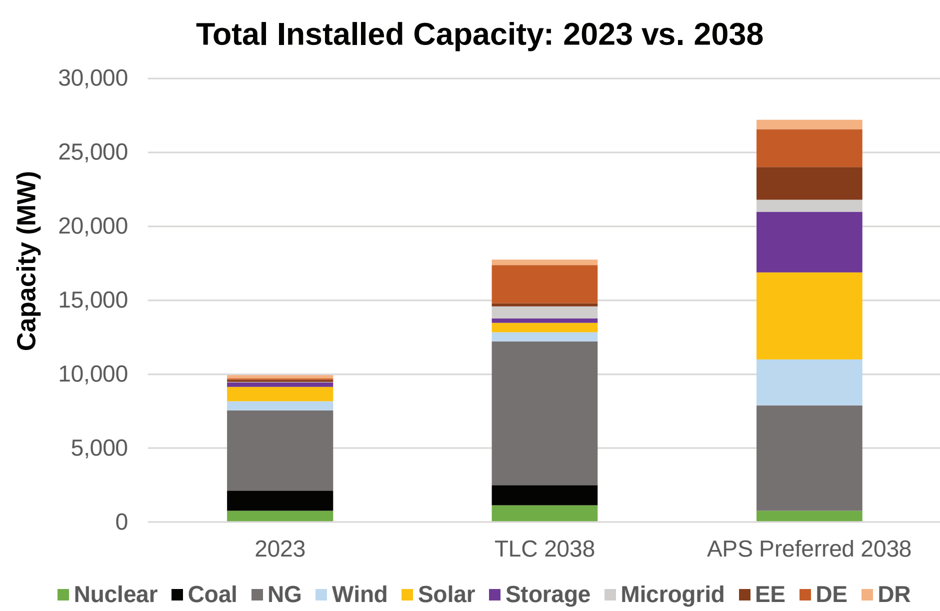

__Figure 18.__ The TLC scenario builds far less capacity than the Preferred Plan because it prioritizes technologies that work on command, rather than those that depend on the cooperation of the weather.

As you can see in Figure 19, APS has an enormous incentive to build more capacity because the utility will earn more profit. Under its Preferred Plan, APS stands to earn more than $16.7 billion in profits through 2038, compared to only $4.7 billion under the TLC scenario.

Because the TLC scenario prioritizes utilizing dispatchable power plants, it is more reliable than the Preferred Plan, which relies heavily on assumed energy efficiency and demand response programs to maintain reliability. Figure 20 shows the hourly performance of the fleet in the TLC scenario during the same time period examined above. The portfolio is able to easily maintain reliability because it contains enough dispatchable capacity to meet 98 percent of the peak load.

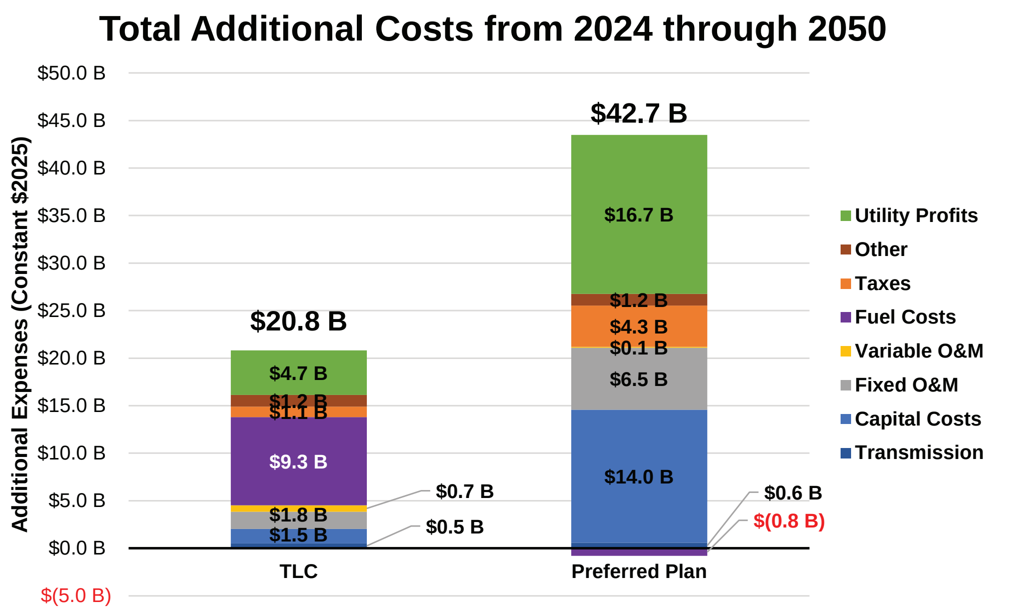

Figure 19. *APS could meet the needs of its customers for less than half of the cost of its Preferred Plan.*

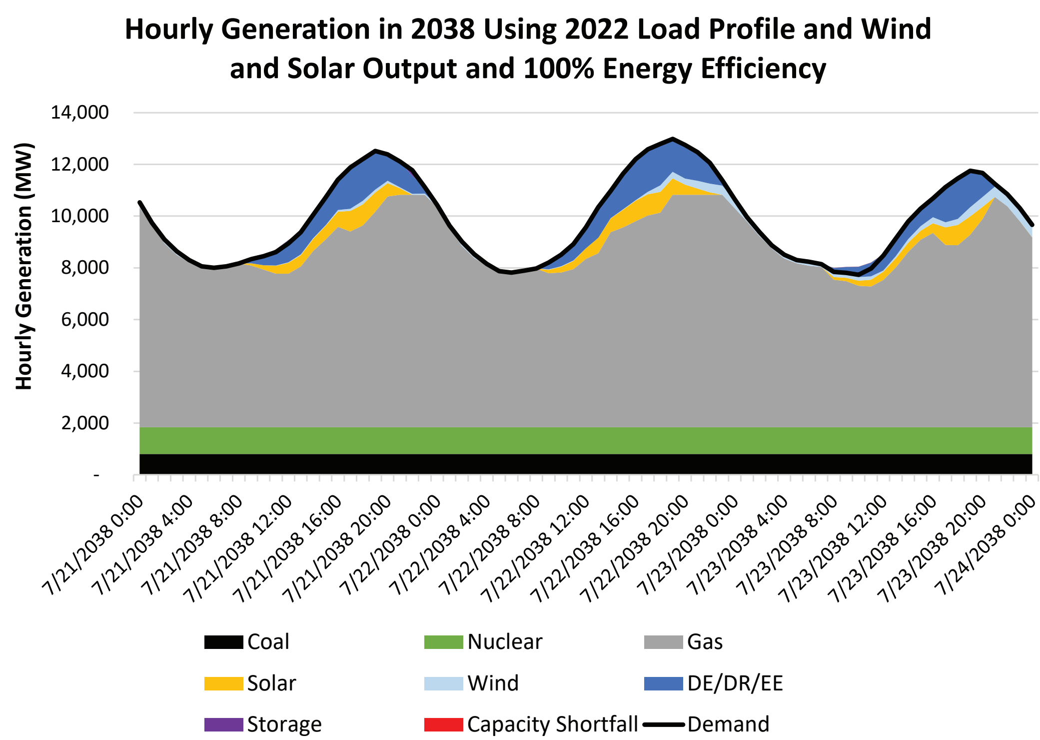

Figure 20. *The TLC scenario is able to meet electricity demand during the high-stress periods discussed above without relying on energy efficiency measures.*

CONCLUSION

Compliance with the APS IRP would cost at least $42.7 billion through 2038. APS families would see their electric bills increase by $96 per month in 2038, compared to 2023 bills. Commercial businesses would see their costs increase by $454 per month and industrial customers, like manufacturers and mines, would see their electric bills increase by $4,640 per month.

The costs incurred in the APS IRP are driven by a massive buildout of solar panels, wind turbines, battery storage facilities, and transmission lines, in addition to the costs associated with higher taxes and utility profits. Under the Preferred Plan, APS would generate $16.7 billion in returns for its shareholders, whereas the TLC scenario would generate just $4.7 billion in utility returns.

While adding power plant capacity to the grid may sound like a good thing, increasing capacity merely to meet the utility's green energy goals rather than meeting electricity demand is an unnecessary cost that will harm APS families and the region's economy. APS ratepayers would be better served by maintaining the existing Four Corners facility and building new natural gas combined cycle plants as described in the TLC scenario.

APPENDIX:

Monthly Average Additional Cost Per Customer

The monthly average additional cost per customer was calculated by dividing the average monthly expense of the APS IRP by the number of electricity customers in the region. This methodology is used because rising electricity prices increase the costs of all goods and services. Businesses will attempt to pass these additional costs onto consumers, effectively increasing the cost of everything. Therefore, this method helps convey the total cost of the APS Preferred Plan on households in a way that is more representative than calculating the costs associated with higher residential electric bills.

Annual Average Rate Per Customer Class

The annual average additional cost per residential, commercial, and industrial rate class customers was calculated by applying the overall cost per kWh of the APS Preferred Plan during the time horizon of the study to rate classes based on historical rate factors in APS. Rate factors are determined by the historical rate ratio (rate factor) of each customer class.

For example, electricity prices for residential, commercial, and industrial rate classes in APS were 15.31, 12.78, and 10.40 cents per kWh in 2023, respectively. Based on all-sectors electricity prices of 13.83 cents per kWh, residential, commercial, and industrial rates had rate factors of 1.11, .92, and .75, respectively. This means that, for example, residential customers have historically seen electricity prices 11 percent above general rates. This analysis continues these rate factors to assess future rate impacts for each rate class.

The table below shows annual additional electricity rates by customer class using the cost of the APS IRP and adjusting for the rate factor described above in cents per kWh.

	Residential	Commercial	Industrial	Average
2023	15.31	12.78	10.40	13.83
2024	17.45	14.56	11.84	15.75
2025	18.88	15.75	12.82	17.05
2026	20.16	16.82	13.69	18.21
2027	20.74	17.31	14.08	18.73
2028	21.07	17.58	14.31	19.03
2029	21.60	18.02	14.66	19.50
2030	22.01	18.36	14.94	19.87
2031	22.13	18.46	15.02	19.98
2032	22.20	18.52	15.07	20.05
2033	22.01	18.36	14.94	19.87
2034	21.92	18.28	14.88	19.79
2035	21.83	18.21	14.82	19.71
2036	21.84	18.22	14.82	19.72
2037	21.89	18.26	14.86	19.76
2038	21.84	18.22	14.82	19.72

Assumptions for Levelized Cost of Energy (LCOE) Calculations

The main factors influencing LCOE estimates are capital costs for power plants, annual capacity factors, fuel costs, heat rates, variable operation and maintenance (O&M) costs, fixed O&M costs, the number of years the power plant is in service, and how much electricity the plant generates during that time which is based on the capacity of the facility and the capacity factor.

LCOE values for existing coal, nuclear, and natural gas generators were estimated using historical FERC Form 1 filings for APS generators. These LCOE values are inserted into the model and adjusted annually based on annual capacity factors for existing resources.

LCOE values for new power plants were calculated using data values provided by APS in its 2023 IRP. The cost of repowering power facilities that require it at the end of their useful lives is accounted for in each value. These values are described in greater detail below.

1. Capital Costs, and Fixed and Variable Operation and Maintenance Costs

Capital costs and expenses for fixed and variable O&M for wind, solar, and battery storage were obtained from data provided by APS in its 2023 IRP.

2. Unit lifespans

Different power plant types have different useful lifespans. Our analysis takes these lifespans into account for our Levelized Cost of Energy analysis.

3. Onshore and Offshore Wind turbines last 20 years

Federal LCOE estimates seek to compare the cost of generating units over a 30-year time horizon.

The APS IRP assumes Southwest wind facilities will have a 40 year book life, or useful lifetime. This is problematic for wind energy LCOE estimates because the National Renewable Energy Laboratory reports the useful life of a wind turbine is only 20 years before it must be repowered. Furthermore, the Lawrence Berkeley National Laboratory Land Based Wind Report indicated retrofitted turbines in 2023 ranged in age from 11 to 15 years old; the median age was 13 years.[15]

Our analysis corrects for APS's unrealistic useful lifetimes by using a 20-year lifespan for wind projects before they are repowered and need additional financing.

4. Solar panels last 25 years

APS uses a book life of 40 years for solar panels in its analysis. Our analysis uses a 25-year lifespan for solar because this is the typical warranty period for solar panels. These facilities are rebuilt after they have reached the end of their useful lifetimes.

5. Battery storage lasts 15 years

APS uses a book life of 20 years for battery storage facilities. Our analysis assumes battery storage facilities are expected to last for 15 years. Battery facilities, like wind and solar, are rebuilt after reaching the end of their useful lifetimes.

6. Fuel Cost Assumptions

Fuel costs for existing and new power facilities were derived from data provided by APS in its 2023 IRP. These costs are propriety and are not disclosed in this report.

7. Levelized Cost of Transmission Lines, Taxes, and Utility Profits

This report calculated the additional levelized transmission, property and income tax, and utility profit expenses resulting from each new power source during the course of the model and according to the additional capacity in MW installed and generation in MWh of that given source. Capacity installed is used to determine capital costs and additional expenses (state taxes, and utility profits) of each electricity source over the course of its useful lifespan.

8. Transmission Lines

This report utilizes the proprietary assumptions in the APS IRP for transmission expenses. This report doubles this expense for the remaining years of the report.

9. Utility Returns

The amount of profit a utility makes on capital assets is called the Rate of Return (RoR) on the Rate Base.

[15] ***Lawrence Berkeley National Laboratory,*** *"Land-Based Wind Market Report 2024 Edition," Accessed February 7, 2025, https://emp.lbl.gov/sites/default/files/2024-08/Land-Based%20Wind%20Market%20Report_2024%20Edition.pdf.*

For the purposes of our study, the capital structure used is that of Arizona Public Service (APS): 49.65 percent debt and 50.35 percent equity, and a return on debt of 6.35 percent and return on equity of 8.7 percent.

10. Property Taxes

Property tax payments for utilities were calculated to be 1 percent of the undepreciated cost of generation assets installed in each respective scenario.

Assumptions for The Always On Levelized Cost of Energy Calculations

This report also calculated and quantified the Always On LCOE for wind and solar energy on the entire energy system. The expenses needed to mitigate intermittency stem from the need to build backup battery storage facilities to provide power during periods of low wind and solar output, which we refer to as battery storage costs and natural gas peaking costs, in this report and the need to "overbuild and curtail" wind and solar facilities to limit the need for battery storage. It is important to note that these costs are highly system specific to the mix of resources being built and operated in any given area.

1. Battery Storage Costs

We calculate battery storage costs by determining the total cost of building and operating new battery storage facilities to meet electricity demand during the time horizon studied in the APS IRP. These costs are then attributed to the LCOE values of wind and solar by dividing the cost of load balancing by the generation of new wind and solar facilities (capacity-weighted).

Attributing battery storage costs to onshore wind and solar allows for a more equal comparison of the expenses incurred to meet electricity demand between non-dispatchable energy sources, which require a backup generation source to maintain reliability, and dispatchable energy sources like coal, natural gas, and nuclear facilities that do not require backup generation.

2. Natural Gas Peaking Costs

We calculate natural gas peaking costs by determining the total cost of building and operating new natural gas peaking capacity to meet electricity demand during the time horizon studied in the APS IRP. These costs are then attributed to the LCOE values of wind and solar by dividing the cost of load balancing by the generation of new wind and solar facilities (capacity-weighted).

Attributing natural gas peaking costs to onshore wind, and solar allows for a more equal comparison of the expenses incurred to meet electricity demand between non-dispatchable energy sources, which require a backup generation source to maintain reliability, and dispatchable energy sources like coal, natural gas, and nuclear facilities that do not require backup generation.

3. Overbuilding and Curtailment Costs

The cost of using battery storage for meeting electricity demand during periods of low wind or solar output is prohibitively high, so many wind and solar advocates argue that it is better to overbuild renewables, often by a factor of five to eight compared to the dispatchable thermal capacity on the grid, to meet peak demand during these low wind and solar periods. These intermittent resources would then be curtailed when wind and solar output improves.

As wind and solar penetration increase, a greater portion of their output will be curtailed for each additional unit of capacity installed.[16]

This "overbuilding" and curtailing vastly increases the amount of installed capacity needed on the grid to meet electricity demand during periods of low wind and solar output. The subsequent curtailment during periods of high wind and solar availability effectively lowers the capacity factor of all wind and solar facilities, which greatly increases the cost per MWh produced.

Our model indicated there would be significantly larger periods of curtailment in the future grid due to the large capacity additions of wind and solar resources. Annual curtailment levels for this model were estimated based on hourly load forecasts and were found to reach up to 19 percent of total wind and solar generation by the end of the model (see Figure 21).

Rising rates of curtailment stemming from the overbuilding of the grid effectively lower the capacity factor of all generating resources, thereby increasing the levelized cost of energy, which is a calculation of power plant expenses divided by the generation of the plant.

[16] ***Dev Millstein et al.,*** *"Solar and Wind Grid System Value in the United States: The Effect of Transmission, Congestion, Generation Profiles, and Curtailment, Joule, July 2021, https://www.sciencedirect.com/science/article/pii/S2542435121002440.*

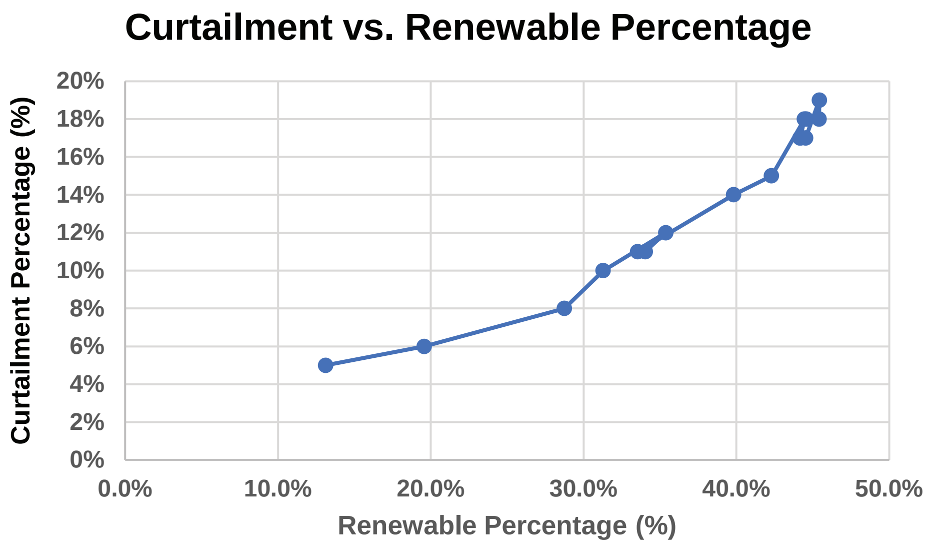

Figure 21. *Curtailment increases to 19 percent by 2038 as more intermittent generation is brought online.*

Peak Load

Our analysis assumed a peak load of 13,100 MW for each historical test year, consistent with data provided by APS in its 2023 IRP.

Cost of Carbon

Figure 21 uses the values below for the cost of carbon dioxide emissions in the APS service territory.

TABLE D-11. CARBON DIOXIDE

YEAR	CO2 COST ($/METRIC TON)
2023	$0.0
2024	$0.0
2025	$0.0
2026	$0.0
2027	$0.0
2028	$25.1
2029	$25.8
2030	$26.4
2031	$27.1
2032	$27.7
2033	$28.4
2034	$29.1
2035	$29.9
2036	$30.6
2037	$31.4
2038	$32.2

Note: CO2 numbers based on CA 2023 CO2 cost escalated at 2.5% (begin in 2028)

Electricity Consumption Assumptions

Our model estimates electricity consumption in 2038 using hourly load shape from 2019-2023. Electricity consumption is incrementally increased every year from 2024 to 2038 to arrive at the APS projected 2038 demand and energy usage levels, which was around 63 gigawatt-hours (GWh).

Energy Storage Dispatch

Energy storage is assumed to be saved for periods of high demand with low wind and solar output. This differs from modeling exercises performed by APS, where storage facilities are assumed to use locational marginal price (LMP) arbitrage to determine when these resources would be economically dispatched. For each day modeled, the energy storage algorithm forecasted one week ahead to find opportune times to charge and discharge energy and maximize profitability.

This decision was made because using storage systems to capture higher prices via arbitrage could lead to situations where the energy storage was depleted before a period of low wind and solar output, leaving the system short of energy.

Round trip efficiency for battery storage capacity was assumed to be 95 percent and all batteries are estimated to be fully charged at the start of each test year.

Hourly Load, Capacity Factors, and Peak Demand Assumptions

The hourly load shape used in our modeling was extrapolated using APS load shapes from 2019-2023 obtained from EIA and projected monthly peak demand in 2038. This resulted in a peak demand of 13.1 GW in 2038.

Hourly output from intermittent generating resources, such as wind and solar, were derived from the U.S. Energy Information Administration (EIA) from the APS balancing authority.

Load Modifying Resources

Our model allows for the use of Load Modifying Resources (LMRs), or energy efficiency (EE) and demand response (DR) in determining how much reliable capacity will be needed to meet peak electricity demand in the TLC scenario. However, we believe that DR resources are being inappropriately used by many wind and solar special interest groups to manipulate their models to unrealistically reduce the amount of capacity needed to meet peak demand, and thus artificially suppress the cost of their proposals.

In this way, these groups are essentially manipulating the amount of capacity needed to meet current electricity demand and not providing an apples-to-apples comparison of the cost. Their proposals will effectively place more responsibility on behalf of the customer to keep the grid online. As a result, this report includes various sensitivities that do not include the expected energy efficiency and demand response in
APS's Preferred Plan.

Nuclear Relicensing

All existing nuclear power plants were assumed to remain operational through the model run. This assumption greatly reduced the need for new wind, solar, and battery storage resources to maintain system reliability.

Plant Construction by Type

Under the APS IRP, the utility company would add wind turbines, solar facilities, solar plus storage facilities, battery storage capacity, and build new transmission lines to reduce emissions. AOER used the plant in-service dates outlined in the Preferred Plan for our analysis.

Plant Retirement Schedules

Our model uses retirement assumptions provided by APS in the 2023 IRP, where all coal was retired by 2031.

Time Horizon Studied

This analysis studies the impact of the APS IRP on electricity prices from 2024 to 2038. However, power plants are long-term investments with payoff horizons that extend beyond the scope of this analysis. As such, the total costs highlighted by this study do not represent the total costs incurred under the APS Preferred Plan or the TLC scenario, but rather the total cost that electricity customers would pay through 2038.

Wind and Solar Degradation

According to the Lawrence Berkeley National Laboratory, output from a typical US wind farm shrinks by about 13 percent over 17 years, with most of this decline taking place after the project turns ten years old. According to the National Renewable Energy Laboratory, solar panels lose one percent of their generation capacity each year and last roughly 25 years, which causes the cost per megawatt hour (MWh) of electricity to increase each year.[17] However, our study does not take wind or solar degradation into account.

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[17] ***Liam Stoker,*** *"Built Solar Assets Are' Chronically Underperforming,' and Modules Degrading Faster than Expected, Research Finds," PV Tech, June 8, 2021, https://www.pv-tech.org/built-solar-assets-are-chronically-underperforming-andmodules-degrading-faster-than-expected-research-finds/.*

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