COMMON SENSE INSTITUTE

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AZ Energized:

The Future of Power in Arizona and Its Impact on Our Economy

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About the Author

Glenn Farley is CSI Arizona's Director of Policy & Research. Before joining CSI in 2022, Glenn worked in the Office of the Arizona Governor, most recently as Gov. Doug Ducey's Chief Economist and a policy advisor. In that role he advised on issues of tax, fiscal, and regulatory policy, and was one of the Governor's lead architects of his two major tax reforms – including the 2021 income tax omnibus which phased in a 2.50% flat tax (the lowest in the country). Glenn also led the budget team that produced the Executive revenue forecasts and caseload spending numbers that have helped ensure the longest run of structurally balanced budgets in State history. Glenn has a Master's Degree in Economics from Arizona State University's WP Carey College of Business, as well as a B.S. from Arizona State University. He was born and raised in Arizona where he now lives with his wife and two daughters.

About Common Sense Institute

Common Sense Institute is a non-partisan research organization dedicated to the protection and promotion of Arizona's economy. CSI is at the forefront of important discussions concerning the future of free enterprise and aims to have an impact on the issues that matter most to Arizonans. CSI's mission is to examine the fiscal impacts of policies, initiatives, and proposed laws so that Arizonans are educated and informed on issues impacting their lives. CSI employs rigorous research techniques and dynamic modeling to evaluate the potential impact of these measures on the Arizona economy and individual opportunity.

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Forward

The information used in this report was current as of mid-2023. Most of the data dates to calendar year 2021/22. As new data is released and information changes, the accuracy of assumptions contained herein change as well. More current data available from various sources suggest the conclusions here are – if anything – conservative in terms of the cost and reliability implications of the ongoing generation transition. Recent federal regulatory actions favoring widespread electrification suggest future electricity demand may be higher than we have projected[i].

Summary & Key Findings

A national and even global transition away from coal and towards wind, solar and natural gas generation is occurring; the policy question for states like Arizona is how to conduct this change in a way that protects the stability of its electric grid, keeps prices low, and ensures sufficient electricity generation to meet demand.

Since 2000, the renewable[1] share of the US electricity grid has grown from approximately 0% to 17% of generating capacity. In Arizona, the share as of 2021 was 12% and climbing - over 80% of which is in solar capacity. CSI estimates that continuing this transition over the next 30 years will cost Arizona's utilities and ratepayers $126.6 billion by 2050 (in constant 2021 dollars).

Over the last two decades, the American electricity grid has become less reliable and more expensive for consumers. In 2019, one state – California, long a U.S. leader for power outages – ordered 'rolling blackouts', or outages due to insufficient electricity supply to meet demand (the first such scheduled blackout in two decades)[ii]. In winter 2021, 14 states relied on rolling blackouts to manage demand. At least 9 more had them again in winter 2022 – including the first rolling blackouts in the 90-year history of the Tennessee Valley Authority[iii]. The consequences of recent winter storms for power availability in states like Texas, California, South Carolina, and others suggest that increasing reliance on intermittent power sources is creating risks during seasonal weather events. Prudent grid management by Arizona's utilities, providers, and regulators has so far avoided this here.

- Since 2000, two-thirds of capacity additions in Texas were intermittent wind and solar; less than a third was base-load or backup natural gas. In Arizona, for every gigawatt of solar added, the state added two gigawatts of natural gas. **CSI estimates that had Texas added capacity in a similar ratio to Arizona, it may not have had widespread insufficient power generation during the 2021 winter storm**.
  - For its part, Arizona's electricity grid – again, with a much higher ratio of firm base-load sources like gas and nuclear - maintained general stability despite record demand during the summer 2023 heat wave.
- On average, US electricity customers today experience nearly 8 hours of outage per year – versus just 3 hours a decade ago (+136%).
- Despite plummeting headline costs of wind and solar capacity installation (a 90% decline in the cost of utility-scale PV solar over just 10 years, according to Lazard), U.S. electricity prices have risen 72% since 2001 even as the grid has become more unstable.
- Electricity demand in Arizona is poised to grow 60% over the next 30 years, *even absent widespread electrification* (*Baseline* demand due to population and economic growth). To keep pace with this demand, CSI estimates the state will add 57 GW of new

[1] This growth has largely come from new wind and solar generation, and so we use the terms "renewable" and "intermittent" as generally interchangeable with "wind and solar" throughout this paper.

generation (+206%) – nearly 80% of which will be new wind and solar generation. **This substantial investment is required by the intermittent nature of the new generation**. For example, were this need met with new nuclear capacity, the state may be able to satisfy it with less than 10 GW of new capacity. Nuclear currently supplies one-third of Arizona's electricity.

- Under current capacity investment strategy, by 2050 Arizona electricity prices will rise 47% (in constant 2021 dollars) and average residential bills will reach nearly $2,600/year. To maintain grid reliability after this massive investment in intermittent renewable sources, Arizona's utilities build substantial backup generating capacity (mostly natural gas) that is idle much of the time.
    - This outcome is sensitive to the specific assumptions under our *Baseline* – to the extent actual outcomes deviate from those assumed here, the grid may be more reliable (or less costly) than contemplated.
    - Ultimately, policies and a regulatory environment that facilitate the development of new power generation – particularly firm and dispatchable generation to support the state's new renewable resources – are needed to help us in making this transition and mitigate its effects.
- While wind and solar are assumed to be cost competitive with natural gas, and cheaper than nuclear, coal or other legacy sources, **after accounting for increased backup, storage, and transmission costs, 'true' systemwide costs of a renewable-dependent grid are likely to be significantly higher than a more traditional grid system**.
- Ultimately, state and local policymakers have substantial input into where, how, and when the state adds new generating resources, given the national environment and renewable transition identified in this paper. State policies and a regulatory environment that allow for an "all-of-the-above' resource building strategy and incentivizes reliability risk mitigation will become increasingly important.

Under CSI's *Baseline* scenario, Arizona's electricity grid becomes 67% renewable and 87% carbon-free by 2050 (up from 8% and 43% today). To manage this transition, ratepayers, utilities, and Arizona electricity regulators must be prepared for rising costs and increasing demand for land, resources, and capital to invest in the needed new generating capacity (particularly the dispatchable natural gas plants, which may be particularly difficult to add) to support our increasingly intermittent energy future. Recent history outside of our state provides a cautionary tale of what can happen when this is not managed carefully. **The addition of intermittent wind and solar resources demands simultaneous addition of firm, dispatchable baseload resources (like natural gas) to ensure grid stability during periods of low or no renewable output.** Short-run cost-minimizing strategies may seek to limit these "redundant" additions; we should not fall for this trap.

There may be many good consequences of this transition – lower emissions, a cleaner environment, and a more sustainable energy economy, for example. However, it will be costly

Contributions to Output and Employment from the Utilities Industry

Category	Output in Billions of Dollars	Employment
Total	**$35.49**	**179,987**
Direct	$10.61	13,473
Indirect	$1.74	10,470
Induced	$6.66	49,827
Dynamic	$16.47	106,217

Source: REMI Tax-PI Model

Figure 1

and require a change in perspective from a grid that builds to meet demand to a grid that overbuilds to meet demand *and* generator intermittency – in the future we will need sufficient generating capacity to keep the lights on even when the sun isn't shining.

Introduction & Background

Arizona is at an energy crossroads. For years, the state has enjoyed one of the most reliable and low-cost energy grids in the country. America's largest nuclear power plant – Palo Verde Nuclear Generating Station – has consistently been the largest single energy producer in the country, with an average annual output of about 3.3 gigawatts (enough energy to serve four million people)[iv]. The state's electric utilities generate about 4% of the country's total electricity supply[v] and much of that ends up exported to other markets. According to the Energy Information Association, on average the state has exported nearly 27% of its net annual electricity generation[vi], with most of that being interstate sales to neighboring California.

Using the REMI Tax-PI dynamic input-output model, we can estimate the impact of the utilities industry both directly – in terms of employment, output, etc. – and indirectly – in terms of induced and dynamic effects on the broader Arizona economy from the presence of the industry in the state. While the industry directly employs between 12,000 and 13,000 Arizonans, it indirectly supports some 167,000 jobs and nearly 6% of the state's total economy ($22 billion in Real Gross Domestic Product (GDP)) (Figure 2). Further, the state's favorable electricity market has supported its rapid economic growth. According to the Energy Information Association, the state had the 14th lowest residential electricity prices in the country as of 2022, and by the end of the calendar year its effective average electricity prices were about 12.1% cheaper than the US average. **Were the state's electricity prices closer to that average, Arizona annual economic growth would be between 3% and 7% slower on average than otherwise.** Over a decade, this amounts to nearly 20,000 fewer jobs and $22.1 billion in cumulative lost GDP[vii].

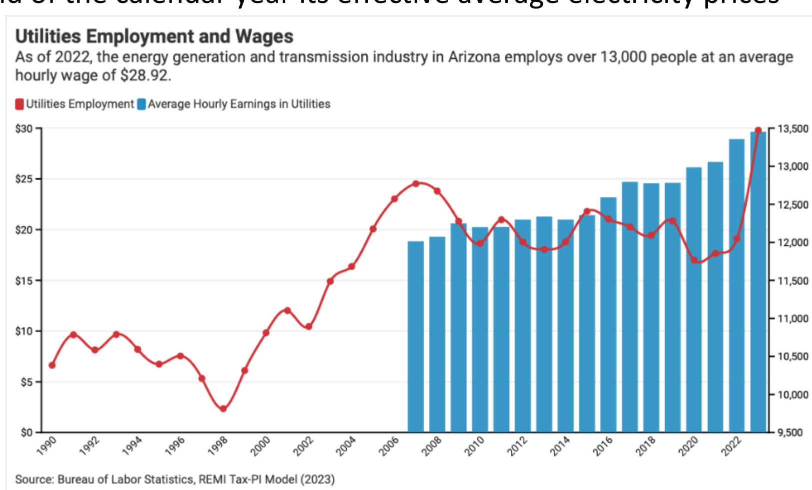

Figure 2

Although Arizona is in a relatively strong position – thanks in part to prudent management by its utilities and public co-op providers - U.S. grid efficiency and reliability are declining (Figure 3). If Arizona follows the same path that has been taken by major markets elsewhere, including California, Texas, and other states and countries, it risks its historically reliable and affordable grid. Palo Verde Nuclear Generating Station's reactors, which produce nearly a third of the state's total electricity generation and is the bedrock of its baseline load, are nearing 40 years old – their originally planned lifecycle. License extensions have given the state another two decades to plan for their replacement. Decades of subsidy, regulation, and political pressure have pushed electric utilities away from investment in traditional -load[viii] capacity from nuclear, gas, and coal plants towards variable sources like wind and solar, straining the nations existing electric grid (which was designed with a consistent and reliable alternating current supply in mind). At the same time, pressures to electrify the nation's economy – including vehicles, cooking, water and space heating, etc. – risk pushing electricity demand higher in the coming years than prior trends.

Policymakers in Arizona must now decide how to respond to these trends given the operating environment. It is unlikely pressure to increase the renewable share of generation will ebb, especially given the scope of public subsidy. Some degree of rising costs and declining reliability relative to historic local norms may be inevitable, and it will be the role of state and local policymakers and the utilities industry to manage and mitigate that. At the same time, the state retains some independent policy flexibility through the regulation of its local utility-scale electricity generation systems and capacity to impose (or relax) source mandates, emission controls, etc. When in 2002 California chose to lead the nation with a first-of-its-kind modern renewable portfolio standard that 20% of the state's electricity come from renewable sources by 2017, its average price of electricity was 11.65 cents/kwh (160% of AZ average); today that cost has nearly doubled to 22.48 cents/kwh (200% of AZ average). Arizona's grid has changed as well; in 2000, the state effectively had no wind, solar, or natural gas generating capacity. Nuclear and coal power provided nearly all the state's electricity supply. Today, wind, solar, and natural gas have been the largest beneficiaries of new capacity investments since 2000, and the composition of our grid has changed dramatically (Figure 4). Arizona Public Service, Salt

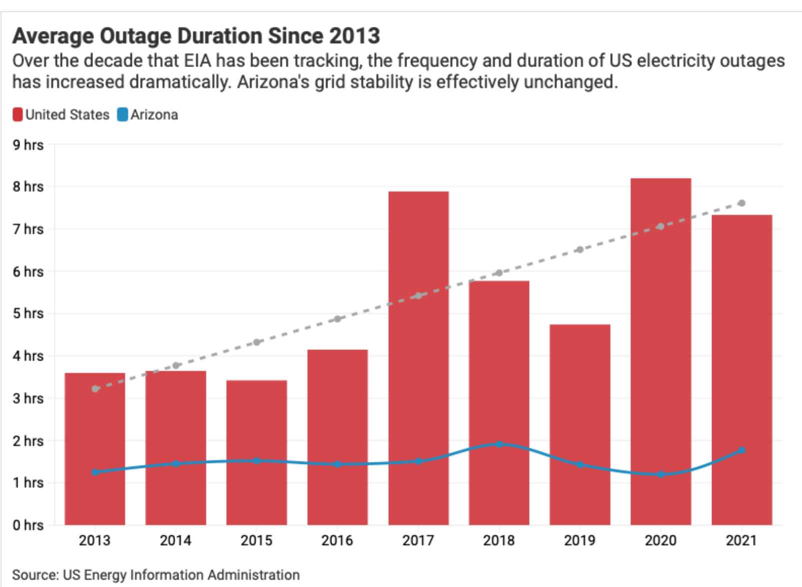

Figure 3

River Project, and other major utility providers in the state have made various public commitments about continuing this gradual energy transition in the coming decades.

This paper analyzes the potential consequences of these changes for our grid.

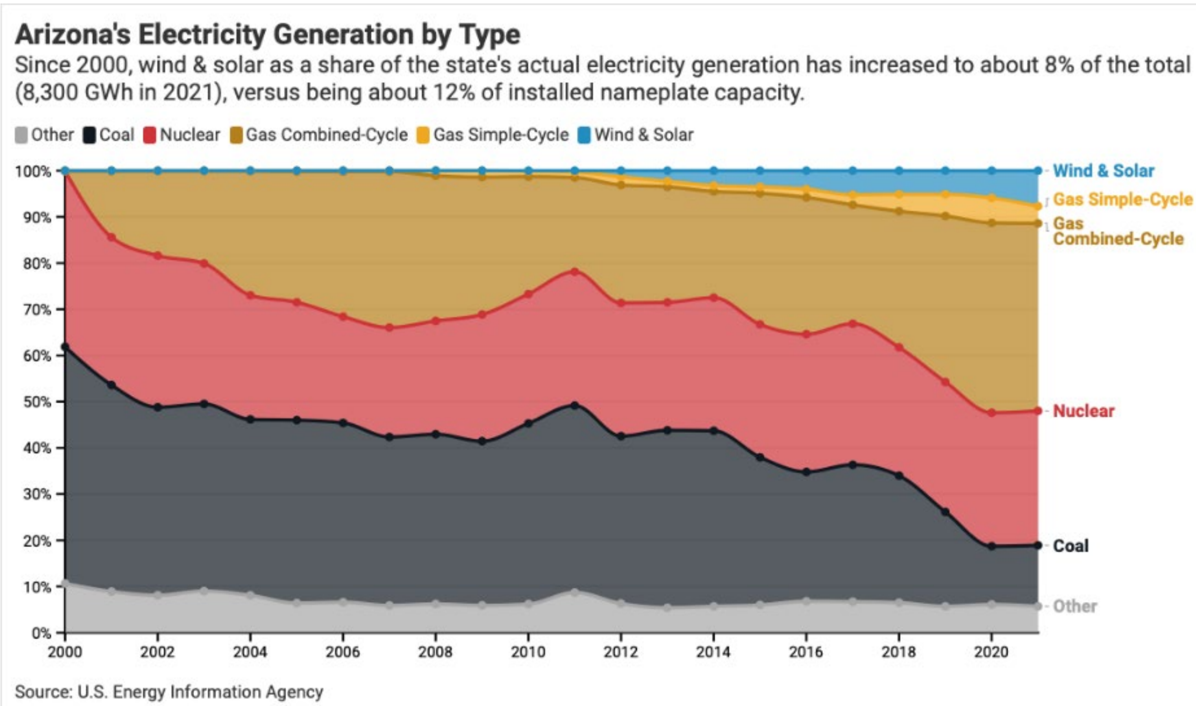

Figure 4

21st Century American Energy Policy

Since the turn of the millennium, American energy investment, investors and customer demand, and public policy have been laser focused on the development and deployment of renewable sources through a combination of state renewable portfolio standards, federal tax credits and subsidies, state subsidies, and market forces. In 2002, California adopted the first "modern" statewide renewable portfolio standard. The Federal Energy Policy Act of 2005 required all American public utilities regulators to consider implementation of "net-metering" policies, which enable electricity customers to make use of grid electricity net of their independent distributed generation, and to feed excess generated electricity back to the grid (which a grid operator then compensates the customer for). As of 2022, there are at least two federal tax credits that directly support wind and solar energy: the Production Tax Credit and the Investment Tax Credit, which together provide ~$2.9 billion annually. Additionally, the solar industry benefits from residential and commercial tax credits that offset some of the cost associated with distributed (non-utility scale) generating capacity installations. Generally, only renewable generation sources are significant beneficiaries of dedicated production tax credits

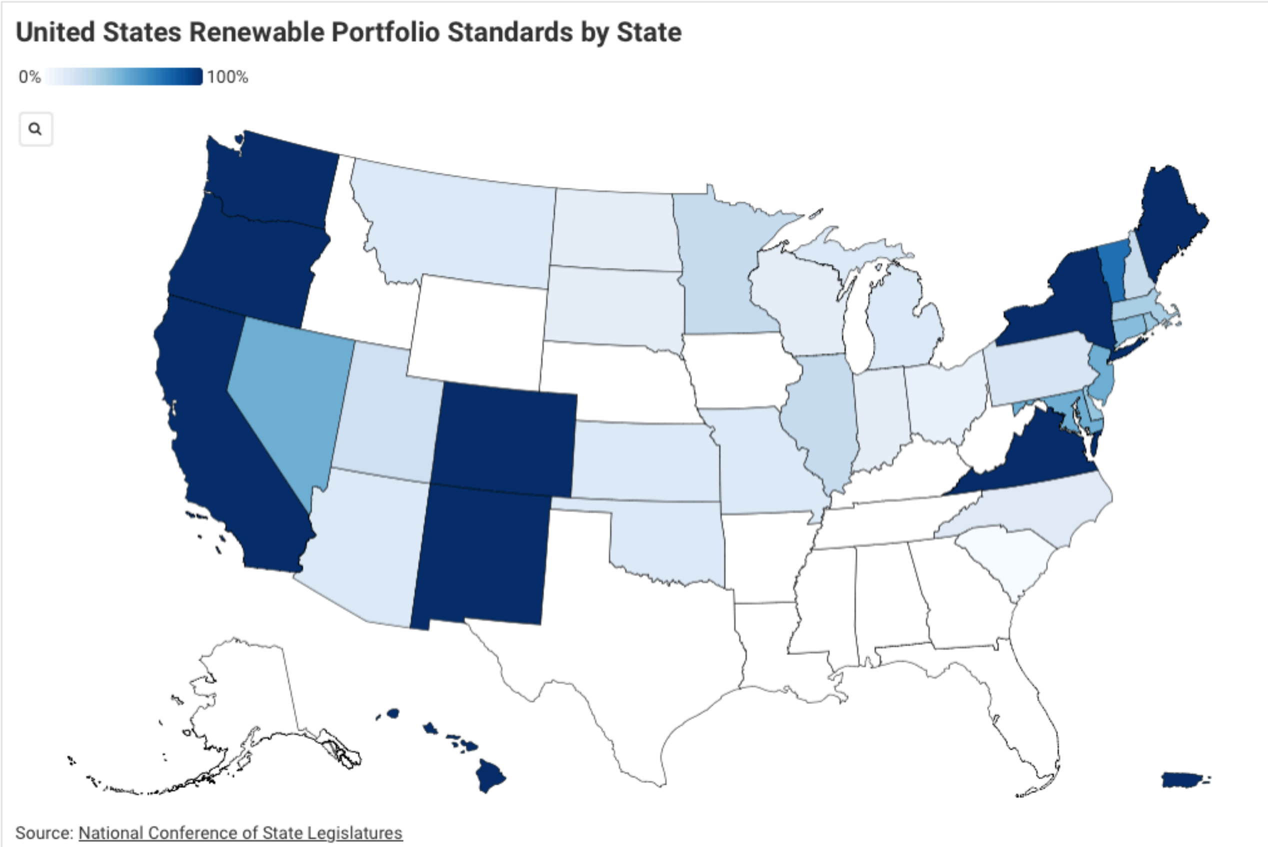

Figure 5

in the United States. Another $28 billion in direct expenditures by Federal agencies supported the wind and solar industries between 2010 and 2019 (nearly 90% of *all* direct Federal support of energy generation over that period), according to the Texas Public Policy Foundation, or about $2.8 billion in direct federal support annually[ix]. While some Production Tax Credits are available for other technologies (like nuclear and hydrogen) historical utilization has been *de minimis* or even zero.

According to the Energy Information Administration, renewable portfolio standards are state policies designed to “increase the use of renewable energy sources for electricity generation”. While policy structure and details vary widely from state to state, generally speaking, modern standards of the type enacted by California in 2002 require a fixed proportion of a state’s electrical supply come from renewable, carbon-free sources by a certain date or year. For example, California’s current standard requires 100% “clean energy” by 2045 (one of the first all carbon-free mandates in the US); Arizona’s standard requires 15% “renewable sources” by 2025. According to the National Conference of State Legislatures, as of last year, 30 states had active renewable portfolio standards (including Arizona), and another 3 states have voluntary clean energy goals (Figure 5).

According to an analysis by the Lawrence Berkeley National Laboratory, half of all growth in renewable energy generation capacity since 2000 is associated with state portfolio standard requirements[x]. However, the standards alone cannot fully explain rapid adoption of renewable technologies. For example, since 2006 Texas has added over 41,000 megawatts of wind and solar generating capacity despite having no adopted portfolio standard; over the same period all other generating capacity has *declined* by 2,700 megawatts. For context, there were about 140,000 megawatts in total generating capacity in Texas as of 2021.

An analysis by UT Austin found that state financial support for renewable energy in California alone (excluding the value of portfolio standard generation mandates) averaged $1.2 billion/year over the past decade[xi]. While California is between 12% and 15% of the US economy, it also likely has the most aggressively interventionist and pro-renewable energy policies in the country; assuming its support accounts for 20% of state support nationwide, we can estimate another approximately $6 billion in annual state and local expenditures in support of the generation of renewable electricity (Figure 6). In many ways, these historical figures are dwarfed by the potential scope of new subsidies contained in recent federal legislation – which some analysts have estimated could inject another **$40 billion per year** over the next decade[xii].

Average Historical Value of Direct Public Support of Renewable Energy Systems
Excluding the value of portfolio standards and other mandates, whose costs are borne by ratepayers

Expenditure Type	Annual Amount
Federal Tax Credits	$2,900,000,000
Federal Direct Expenditures	$2,800,000,000
State & Local Support	$6,000,000,000
Total	**$11,700,000,000**

Source: Texas Public Policy Foundation, UT Austin Energy Institute, CSI estimates for the period 2010-2019

Figure 6

Considered collectively, the combination of direct public support, mandates and portfolio standards, and public and investor demand has encouraged the United States to transition increasingly towards renewable energy sources (particularly wind and solar) for utility-scale electricity generation over the past twenty years. Indeed, of approximately 325,000 megawatts of nameplate generating capacity added since 2000, nearly 60% is attributable to wind and solar projects. Another 280,000 megawatts were in the form of natural gas powerplants (including nearly 100,000 megawatts in less efficient simple-cycle facilities that are typically used to provide redundancy for wind and solar capacity rather than regular base load[xiii]), meaning that excluding wind, solar, and backup (not 'base load') natural gas, the US has *net removed* capacity over the first two decades of the 21st century.

Over the same period, quoted estimates of the cost of electricity produced by renewable sources have fallen precipitously. Various estimates using the "levelized cost of electricity" (LCOE[xiv]) assert that prices of electricity generated by wind and solar sources have fallen by between 40% and 80% since 2010[xv]. A study by Lazard purports that the cost of utility-scale solar power generation has fallen from $359/MWh in 2009 to just $37/MWh today (-89%), while the cost of onshore utility-scale wind generation has fallen from $135 to $40 (-70%)[xvi]. An article from 2019 asserts that "renewable energy is now the cheapest option – even without

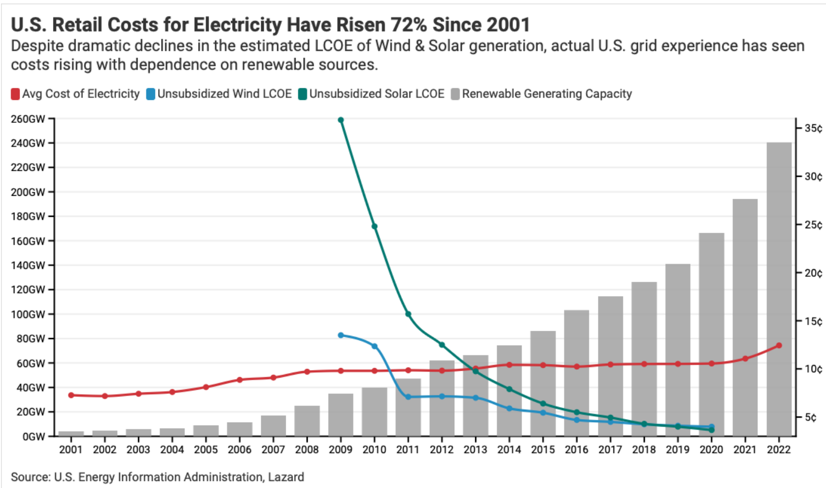

Figure 7

subsidies"[xvii]. Counterintuitively, though, American electricity costs have been increasing as the grid has become more reliant on wind, solar, and gas since 2000. According to EIA data, **average electricity prices nationwide have increased 72% since 2001** – and doubled in California, which has been one of the country's most aggressive adoptees of renewable sources.

What accounts for the apparent disconnect between standardized cost estimates of electricity by source and actual customer rates (Figure 7)? How has this relatively rapid change in generation technologies impacted the grid?

The Texas Experience

In February 2021, a series of winter storms struck much of the central United States – stretching from the normally cold northern latitudes to the southern tips of (typically warm) central Texas. On February 15th, temperatures in parts of central and southern Texas reached all-time recorded lows for the regions and were lower than low temperatures at the same time in Anchorage, Alaska[xviii]. At the storm's peak, over 4 million Texas households would be without power – or nearly 40% of the state[xix]. This outcome was particularly striking given Texas' position as an energy powerhouse; in addition to being the second-largest economy in the country, Texas is by far its largest power producer. In 2021, Texas had 12% of all domestic electricity generating capacity and generated about 12% of the nation's electricity. California – the country's largest state – has just 7% of the nation's generating capacity and produces less than 5% of its electricity.

In addition to having the nation's largest energy industries – both in terms of domestic energy generation and in terms of energy export – Texas has a vibrant and competitive retail electricity market. In 1999, the state's electric utility deregulation left behind the local-monopoly model used in many states in favor of a system of free entry. A power retailer in Texas is free to buy electricity from any state generator of choice; correspondingly, power producers are free to enter or exit the Texas market without the consent of a local public utility. As of 2022, there were 494 power generation companies in Texas, and over 300 electricity retailers[xx]. For perspective, there are 3 principal electricity providers in Arizona's regulated utility system (Arizona Public Service, Salt River Project, and Tucson Electric Power), and another thirteen smaller local providers[xxi]. In general, power providers in Arizona have a guaranteed service area, and contracts with power generators to source electricity for its market, while providers in Texas can compete freely for customers within the state. To protect its market system, the grid in Texas is also almost entirely isolated from the rest of the country – this creates an "intramarket" system which avoids some federal regulatory requirements.

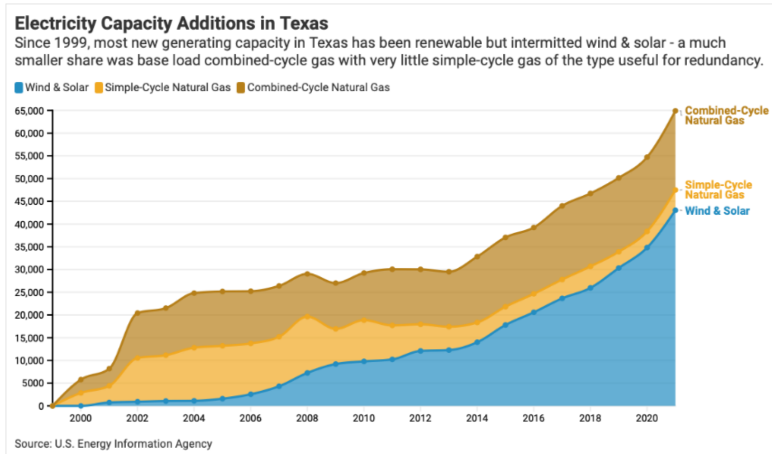

Figure 8

Since 1999 and market deregulation, Texas has added more than 63 gigawatts of generating capacity (Figure 8), or nearly 20% of all US capacity increases. This is particularly remarkable given, again, the closed nature of Texas' grid; electricity producers in the state generally cannot export excess power to other markets. Also strikingly, Texas' "independent power producers" have added more than 100 gigawatts of generating capacity since deregulation (and legacy utility providers have removed nearly 40 gigawatts in capacity, making up the balance)[xxii]. At the same time, after initially rising in the years following deregulation as new startups entered the market and regulatory price floors prevented incumbent providers from cutting prices, electricity prices in Texas have fallen and are about 17% cheaper than the US average (10.2 cents per kilowatt-hour on average across all customers in 2022) (Figure 9). Given this evidence and absent the 2021 winter storms, some might have argued deregulation appeared to have been successful in terms of increasing consumer choice; increasing electricity supply; and reducing prices.

Also of note, Texas has accomplished this through rapid and aggressive investment in renewable generating capacity. Recall, Texas lacks any modern "renewable portfolio standard" of the type adopted by places like California. A 1999 law required power companies have a 10 GW renewable generating capacity by 2025[xxiii], but in practice the statute is entirely nonbinding; in fact, the state likely exceeded this commitment altogether by 2009 (more than a decade ahead of schedule). The state's Republican-dominated politics are reputed to be friendly towards the large domestic hydrocarbon industry and it is unlikely Texas can compete with California in terms of the magnitude of public support for its renewable energy industry. Despite this, the state today has 44 gigawatts in renewable generating capacity – almost all of which was added after electricity market deregulation and by local independent providers – and the largest supply of 'nameplate'[xxiv] wind power capacity in the country (and is the fifth largest wind power producer in the world)[xxv]. The Texas experience is particularly intriguing because it runs contrary to the model for the broader United States – falling prices in the face of rising dependence on renewable sources, perhaps attributable to the state's relatively unique competitive market model.

Through 2021, Texas appeared to be the model for how a state could achieve a rapid transition to renewable energy while lowering electricity prices and preserving customer satisfaction and grid reliability. Texas electricity prices were essentially flat between 2000 and 2020, even as average US prices, excluding Texas, effectively doubled over the same period. Unfortunately, though, the market system failed to adequately price in extreme-event reliability, and the frenzy of subsidy and interest in wind, solar, and other renewable energy systems ensured that insufficient baseload capacity investment was made in the state after 2000 to enable smooth operation during highly uncertain and infrequent events. Effectively, the state's decision to abdicate direct market control through the regulated-utility model ensured that instead the state would become almost entirely captured by the global renewables building boom. There was massive demand to build renewable sites somewhere to access subsidies and satisfy public and investor demand; Texas offered the combination of an open market, cheap costs of doing business, and wide open spaces these developers needed to build quickly. The systems fragility became clear on the morning of February 15, 2021.

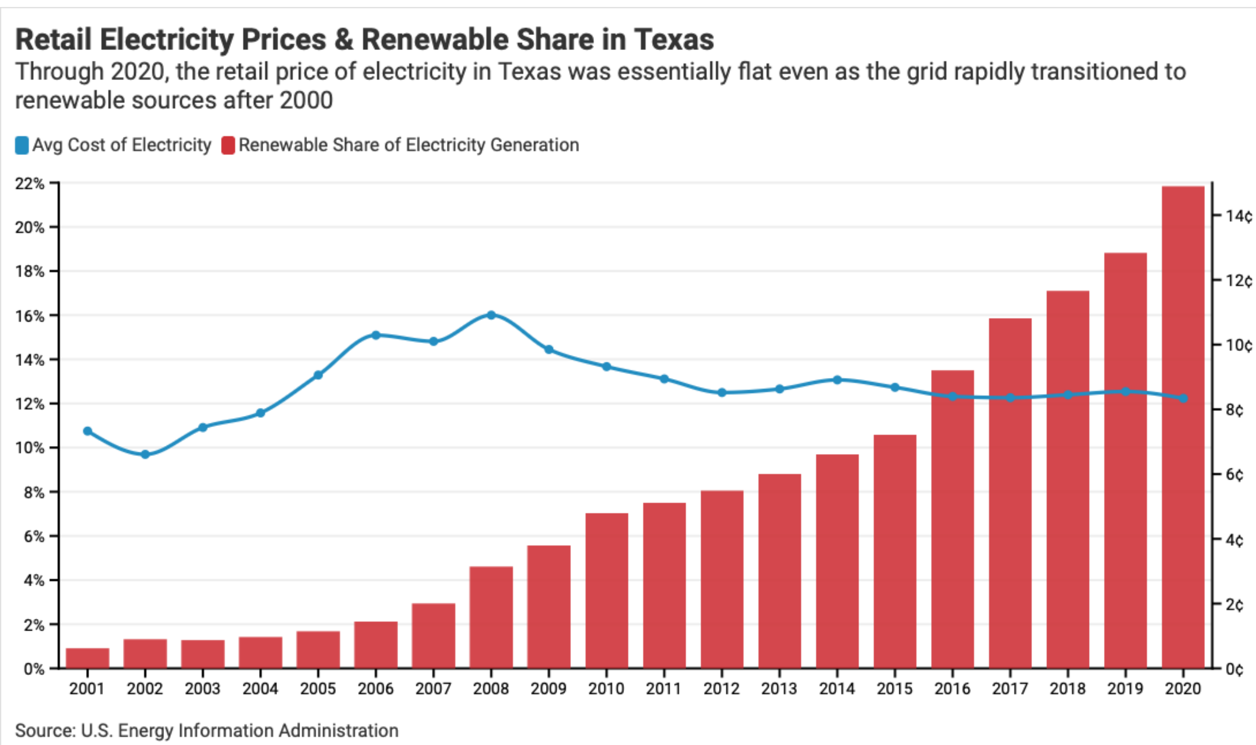

Figure 9

For perspective, recall that as of 2021 wind and solar constitute about a third of total electric generating capacity in Texas – up from essentially 0% at the beginning of the 21st century. Recall also that wind and solar constitute two-thirds of all new capacity added in the state since 2000; while adding 43,000 megawatts of wind and solar capacity, and Texas added only an estimated 4,000 megawatts of new simple-cycle natural gas plants of the type typically used to provide cyclic redundancy for intermittent sources[xxvi].

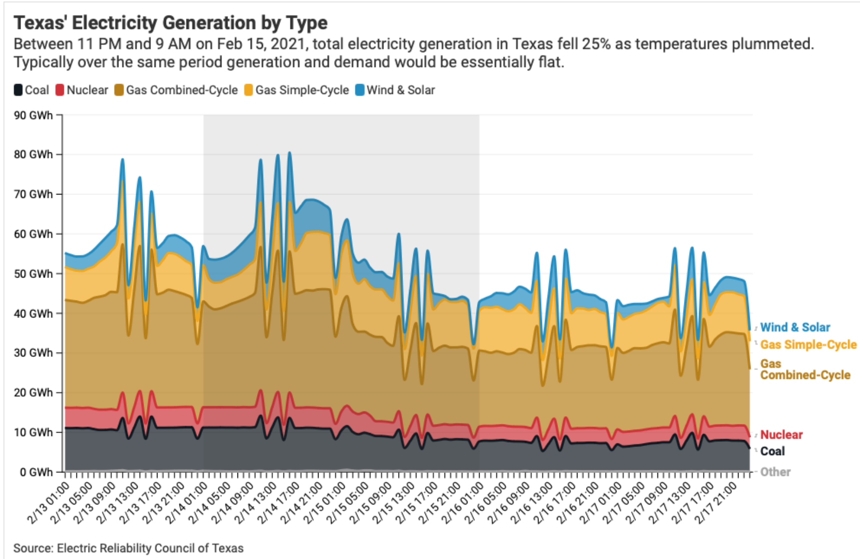

Figure 10

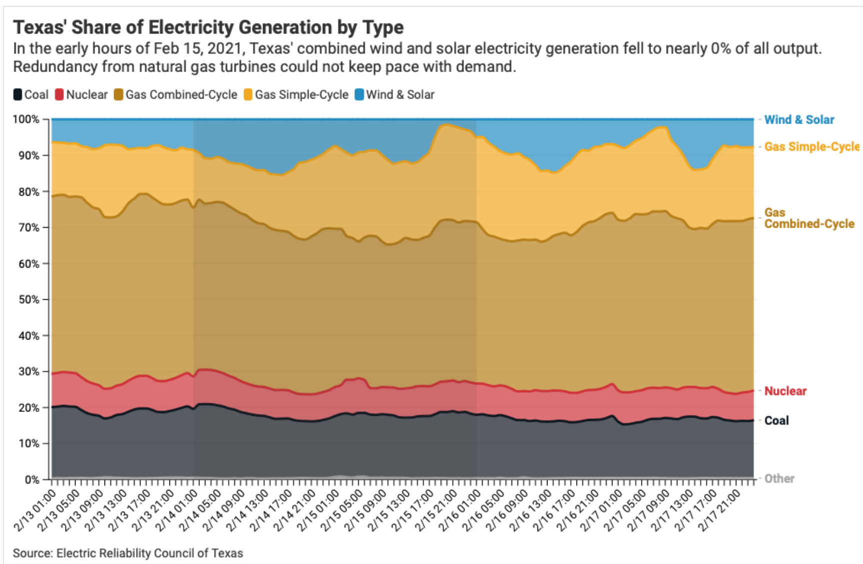

Figure 11

From February 13 to February 14, 2021, a large winter storm developed over the central United States and pushed south into Texas. For the first time on record, the National Weather Service issued winter storm warnings for all 254 Texas counties by February 14[xxvii]. The storm would ultimately cover 80% of the state in snow[xxviii] and be followed by record- or near-record cold in many Texas cities. The most extreme winter weather would be experienced by most of the state during the period February 14 through February 16.

During the two weeks prior to the winter storm, Texas averaged approximately 1,100 GWh of daily electricity generation. On February 14th, demand and generation spiked – to a cumulative 1,500 GWh over the day, including an elevated 66 GWh at 11 PM alone (during the normally subdued evening hours). Over the next four hours generation began to collapse as supply could not keep pace with demand and Texas regulators turned to increasingly aggressive emergency measures to increase grid frequency and reduce electricity demand. At 1:20 AM on the morning of February 15th, the Energy Reliability Council of Texas (ERCOT) began rolling blackouts, and normal grid operations would not resume until February 19th. By 9 AM, electricity generation and demand would fall to 49 GWh – a 25% decline from peak the prior evening. For perspective, during the same period in 2022, electricity demand *increased* from a more normal 41 GWh (at 11 PM on Feb 14, 2022) to 47 GWh (at 9 AM on Feb 15, 2022)[xxix]. Prices in Texas' deregulated market contain significant useful information about supply and demand imbalances relative to other more regulated markets; during the storm, wholesale electricity prices (prices charged by electricity generators to retailers on the state's market) increased 17,900% to a regulatory cap of $9,000 per megawatt hour.

The composition of electricity generation during the extreme winter weather is telling. During 2022 (a "typical" February), wind provided about 28% of Texas' average hourly electricity supply and operated at an average capacity factor of 36% (defined as actual output divided by installed capacity or potential output, capacity factor is a measure of both how reliable and hardworking a power source is over a given period). Simple-cycle natural gas – a comparatively expensive source[xxx] typically used for backup power due to its ability to be turned on and off relatively quickly[xxxi] – had an average capacity factor of 15% and supplied 9% of the state's average hourly needs. **During the three-day period beginning February 14, 2021, wind provided less than 9% of the state's hourly electricity supply at an average capacity factor of just 15%.** Intermittent simple-cycle natural gas, on the other hand, operated at an average capacity factor of over 37% and provided 20% of total electricity supplied during the storm.

While clearly the redundancy intended to be provided by the state's single-cycle natural gas plants failed to materialize (had the plants instead run at 70% capacity, Texas could have generated an additional 7,600 MWh of electricity at 9 AM on February 15 – better but likely still insufficient to meet grid demand given weather conditions), the crisis appears attributable to two primary failures:

1. **Insufficient base load capacity to meet demand:** Despite adding 63 gigawatts of capacity, over two-thirds of that was in the form of intermittent wind and solar; just 17 gigawatts of base load was added, and 100% of that was in the form of combined-cycle natural gas which is potentially more vulnerable to extreme weather events than other technologies like nuclear[xxxii].
2. **Poor performance of the state's renewable and natural gas sources:** Despite massive investment by the state over the past two decades, Texas' wind and solar generators proved to be particularly poorly suited for the winter storm. Had Texas' wind sources operated at just 36% capacity over the three day winter storm period (their 2022 February average) (Figure 12), average hourly generation would have been 6,200 MWh higher than 2021 actuals. Unfortunately, the failure of wind and solar during the storm were compounded by inabilities of backup natural gas capacity to reach theoretical

capacity factors of 70%-80%; combined-cycle gas output peaked at about 80% but only for ~3 hours during the 72-hour storm period, while simple-cycle output never hit 60%.

CSI estimates that in a counterfactual world where Texas had instead added two-thirds of new generating capacity in the form of combined-cycle natural gas and allocated the remainder to wind and solar projects with a small reserve from simple-cycle natural gas, it would have been able to generate an additional 20 GWh of electricity during the peak of the winter storm (given actual performance observed from the states sources). According to ERCOT, at peak the largest instantaneous shortfall between electricity supply and demand during the storm was, coincidentally, 20 gigawatts[xxxiii] – meaning the state likely would have avoided most or all or the blackouts and systemic failures given both the additional available generating capacity and the responsiveness of its dynamic pricing mechanisms. This scenario allows the state's natural gas resources to fail at the same rate as was observed during the 2021 winter storm; even then, their relative overperformance likely allows Texas to satisfy its event-related electricity demand assuming it had scaled its natural-gas resources up proportionately (including infrastructure capacity). Given the current American energy development market, however, the relatively *laissez faire* Texas model probably could not and would not have accommodated this – there is little direct financial incentive for utility providers anywhere to maintain excess natural gas capacity, given, at the margins, all of the fiscal and demand incentivizes favor renewables.

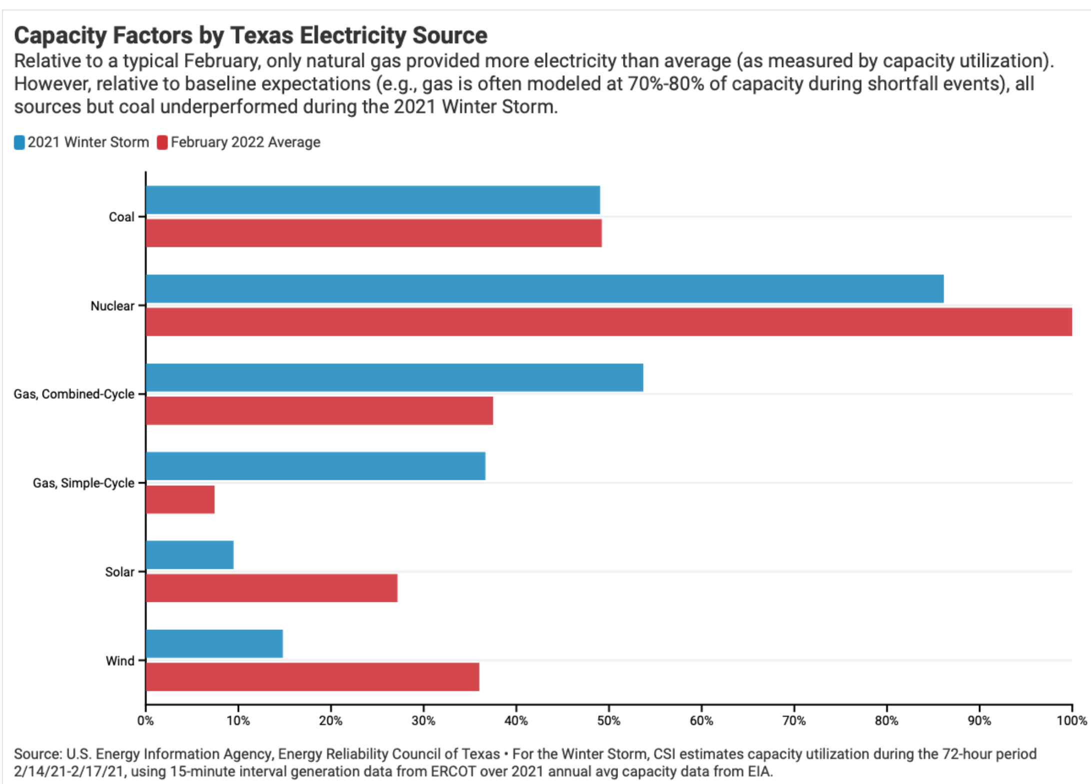

Figure 12

What is Arizona's Energy Plan?

In 2000, Arizona sourced about 80% of the state's electricity from coal and nuclear sources. Natural gas combined made up less than 10% of total generating capacity. However, over the past 20 years utilities have had tremendous incentive – from customer and investor demand, and state and federal regulatory policy – to alter that mix.

Electric Grid Composition in Arizona & Texas

The electric grid in Texas is composed of a greater share of renewable energy sources than Arizona, and the ratio of reserve capacity to renewable capacity is lower. This results in lower costs but greater reliability risk.

2021 Generating Capacity Share	Arizona	Texas
Coal	10.8%	13.1%
Nuclear	14.4%	3.6%
Combined-Cycle Natural Gas	36.6%	30.4%
Simple Cycle Natural Gas	15.3%	20.6%
Wind & Solar	12.5%	31.1%
Other	10.4%	1.2%
Average Rate (per kWh)	**10.60¢**	**9.21¢**
3-yr Avg Outage Duration (hours)	**1.47 hrs**	**10.55 hrs**

Source: U.S. Energy Information Agency

Figure 13

Since then, the state has steadily expanded its gas, wind, and solar generating capacities (Figure 13), while removing coal generation from the grid. Strikingly, however, its generation mix changes have looked very different from those in Texas – approximately two-thirds of the new capacity additions have been in the form of combined-cycle natural gas of the type used to provide consistent and reliable base load capacity. Of the remaining one-third, capacity additions have been roughly split between intermittent wind and solar[2], and backup simple-cycle natural gas.

Although this simple-cycle natural gas capacity is idle much of the time, its existence provides substantial buffer against grid instability problems posed by extreme weather events and the inherent intermittency of alternative sources. And perhaps not coincidentally, had this been the path followed by Texas over the past two decades – as discussed above – it likely would have had a very different experience during the 2021 winter storm. However, these substantial investments in natural gas capacity impose costs on the grid – costs which are passed onto ratepayers. Arizona also has approximately double the amount of industrial-scale energy storage capacity as Texas (1.1% versus 0.6% of grid capacity, respectively), which additionally imposes costs on ratepayers. The

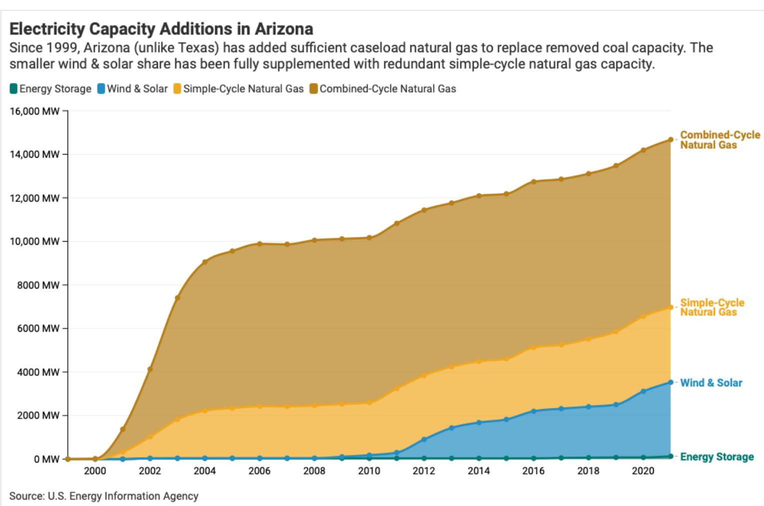

Figure 14

[2] EIA state data on solar capacity includes both utility-scale power plants and small-scale, distributed systems.

net effect, though, is a grid which is highly reliable relative to both recent experience in Texas and relative to the United States, while remaining relatively low-cost. Even using a three-year average due to the extreme weather-related events in Texas during 2021, an electric power customer there can likely anticipate about 10.5 hours of outages in a typical year – versus just 1.5 hours in Arizona (Figure 14).

The availability of abundant and relatively low-cost nuclear electricity has helped insulate ratepayers from some of the costs associated with Arizona's grid composition choices[xxxiv], but the generators at Palo Verde are near their original planned operating life – and a recent license extension has given the state just 20 years of reprieve[xxxv].

Currently, regulated Arizona public utilities are required by the Arizona Corporation Commission (ACC) to generate 15% of their electric energy from renewable sources by 2025. Renewable sources are defined to be wind, solar, geothermal, and other similar technologies; the definition explicitly excludes nuclear and fossil fuels[xxxvi]. Notably, the standard applies to a share of the affected utilities sales, rather than its generating capacity – meaning it is not sufficient that 15% of a utility's *capacity* be from renewable sources, but that 15% of actual net generation (measured by retail sales) come from renewable sources. Additionally, strict limits on the applicability of hydroelectric sources to the renewable portfolio standard – combined with environmental considerations limiting the ability of the state to add new or expand existing hydroelectric sources – mean that the standard *de facto* excludes hydroelectric options

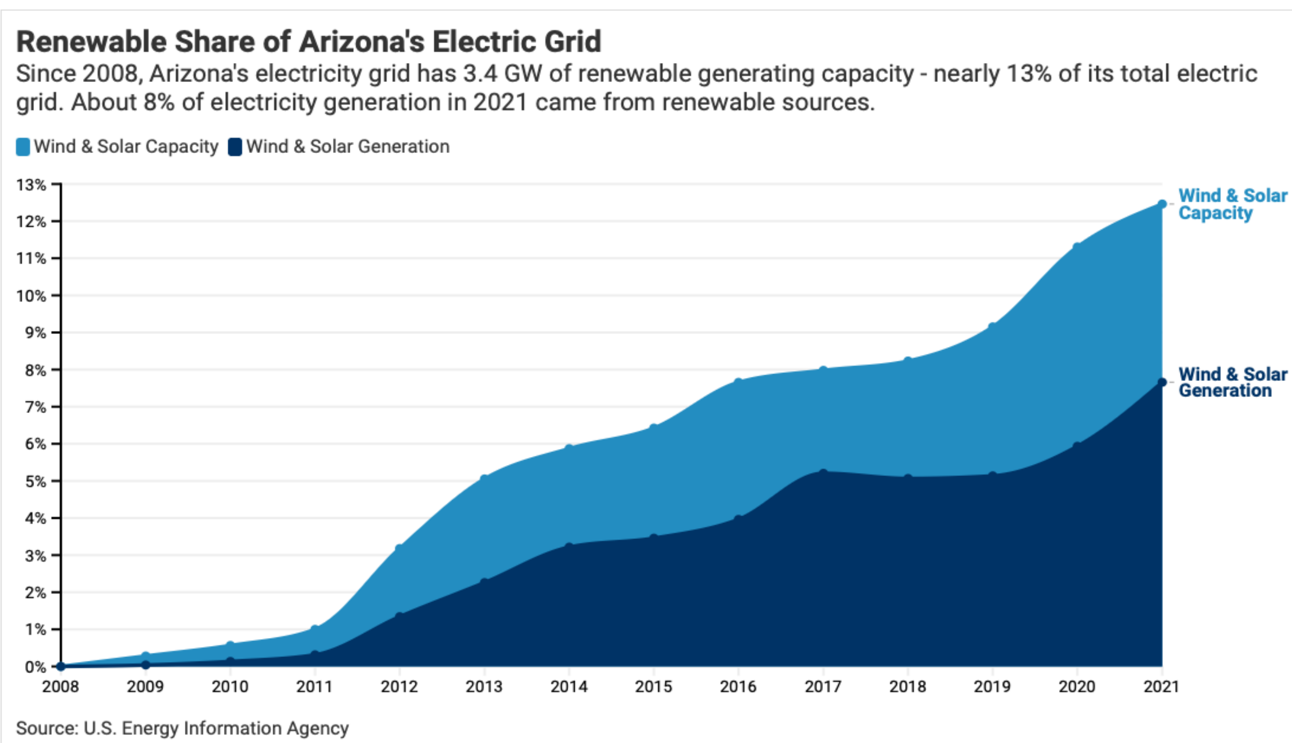

Figure 15

for meetings its requirements (indeed, an analysis of selected compliance filings with the ACC by CSI found no record of a utility sourcing required renewable generation from a hydroelectric source[xxxvii]). Effectively, regulated utility companies comply with the ACC mandate exclusively with wind and solar (mostly solar).

Additionally, there is significant momentum for Arizona electric utilities to source electricity from renewable sources beyond the ACC portfolio standards. Non-regulated Salt River Project has a voluntary plan to source "nearly 50%" of its energy from "carbon-free sources" by 2025, for example and voluntarily sources nearly 9% of its electricity from renewable sources[xxxviii]. Arizona Public Service has made a voluntary commitment to source 100% of its energy from "carbon-free" sources by 2050, including 45% from renewable energy sources[xxxix]. In 2020, the ACC voted to expand its existing portfolio standards by requiring regulated utilities to source 100% of their electric energy from carbon-free sources by 2050, with 50% coming from renewable sources by 2035. Though the rules were ultimately not adopted, they are consistent with and indicative of a general trend in Arizona and United States electrical generation trends – the renewable share of Arizona's electric grid has grown to 13% of total generating capacity in just over a decade.

Simultaneously, there is significant push elsewhere for electrification of the American and Arizona economies, which will likely increase electric energy demand relative to prior trends. Electric vehicle sales are today roughly 6% of the new car market, and subsidies in the federal Inflation Reduction Act combined with general market trends are expected to increase that ratio[xl]. Similarly, there are incentives to electrify the home heating markets, and some states have already taken steps to limit the use of consumer natural gas in new residential construction[xli].

To that end, this report considers only the following scenario based on historical demand trends:

- A ***Baseline*** scenario, where domestic electricity demand grows in proportion to growth in population (for Residential demand) and state economic output (for Commercial and Industrial demand). Export demand is taken as exogenous and grows at the same rate as the US economy. Domestic energy production is assumed to maintain existing nuclear, combined-cycle (base load) natural gas, and hydroelectric capacity. New (base load) capacity is assumed to come exclusively from solar and wind generation (85%/15% split, respectively). Additional capacity additions in the form of battery storage and simple-cycle natural gas are assumed added at a ratio sufficient to support the wind and solar generators under CSI's 'stress test' scenario. Notably, this scenario assumes no net-new base load natural gas capacity beyond what the state already has but does allow for the maintenance and replacement of existing natural gas generators as they age. This scenario also assumes no electrification shocks from the automotive, household, or industrial sectors.

- While only the implications of this *Baseline* scenario are addressed in the following pages, it is clear that public policy is fundamentally changing the nature of electricity demand in the United States. Electric vehicles – today 8% of all new vehicle sales, up from virtually none a decade ago – could increase an average households annual electricity use by nearly 50%. CSI may consider alternative scenarios that look at economic electrification (vehicles, homes, and industry) and its implications for grid size, cost, and reliability in future research.

Additionally, we will consider variations of these scenarios which look at alternative paths for the state's nuclear generating capacity (where it is allowed to sunset or expanded). As we will note below in the *Baseline*, it is probably impractical to replace nuclear generating capacity with alternative carbon-free sources.

For each scenario, we estimate how much new electric generating capacity would be required in Arizona through 2050 and by type. We then estimate the costs of those capacity additions, as well as implications for reliability, electricity rates, and other measures of resource utilization. All net-new generating capacity in the *Baseline* comes from wind and solar sources, supported by new simple-cycle natural gas for intermittent backup use due to resource and technological constraints limiting adoption of battery storage. For simplicity, we additionally assume a flat 2% replacement rate across the state's existing other electric generation portfolio (excluding nuclear and combined-cycle natural gas sources, which are assumed to be maintained but not expanded under the *Baseline* scenario, and coal sources, which are assumed to be replaced at a fixed rate of 7%/year under the *Baseline* until entirely eliminated), implying an effective 50-year useful life on existing hydroelectric, biomass, and other sources. While there has been some discussion of potentially expanding U.S hydroelectric sources as a supplier of renewable base load capacity, in practice, approval and construction of new hydroelectric generating plants appears all but impossible in the contemporary United States. According to EIA data, for example, Arizona has not added new hydroelectric generating capacity since before 1990, and existing hydroelectric generation has declined at an effective annual rate of 2%/year since 2000 (likely a product of declining Colorado river flows).

Electrification – particularly of the vehicle fleet – greatly increases electricity demand in Arizona. For perspective on why this is, consider that a gallon of gasoline (enough to propel a typical vehicle at least 20 miles) contains about 35 KWh of useful energy, while the average US household uses about 30 KWh of electricity *per day*[xlii]. In practice, to achieve affordable electrification of the vehicle fleet would likely require both dramatic reductions in vehicle miles traveled and dramatic increases in grid generating capacity, which is beyond the scope of this paper. We will however analyze costs and feasibility of consumer-side electrification (given current transportation and household needs and trends) in follow-up research. **But we make no claim that households and business will *want* or feasibly *can* electrify**. For existing property, there are conversion costs associated with ending the use of natural gas or (in the case of transportation) gasoline. There are also consumer preferences: many households prefer to cook or eat with natural gas, for example, and industrial consumers often have business needs that lead them to prefer natural gas energy sources to electricity. And this is exclusively a discussion of consumer demand; commercial and especially industrial processes have unique energy demands that are conceptually much more difficult if not altogether impossible to electrify. Ultimately, we can model some of the energy implications, but not broader economic and social implications, of wide-spread electrification.

Finally, numerous constraints that are difficult to model impact the viability of these scenarios. **Construction of new generation projects of this scale would require significant amounts of land, labor, and rare minerals.** The ability to procure these materials affordably and consistently at the pace needed to maintain the resource development schedule contemplated here is not guaranteed, particularly considering that *every other state is trying to do the same thing simultaneously*.

Notes on Renewable Operating Reserves

Under each scenario, the state is assumed to build sufficient redundant capacity (called here "operating reserve") to maintain a sufficient ratio between wind and solar base generating capacity and backup supply under a hypothetical 'stress-test' scenario. For simplicity, we assume backup capacity is provided by a mixture of natural gas (predominantly of the simple-cycle type), battery storage, and pumped storage (Figure 16). Under the *Baseline*, pumped storage capacity is assumed fixed – there have been no pumped-storage capacity additions in Arizona since 2002 and large-scale applications of the technology face similar regulatory and practical barriers as new hydroelectric facilities. SRP recently announced intent to explore a new pumped storage reservoir in northern Arizona, but the projects timeline is at least ten years and contemplates multiple layers of regulatory review at the federal, state and local, and tribal levels; similar proposals in 2021 never made it past an initial discussion phase before being withdrawn[xliii]. Given these historical headwinds, our *Baseline* does not incorporate new pumped storage, but that can be amended as new data and information on some newly proposed projects matures.

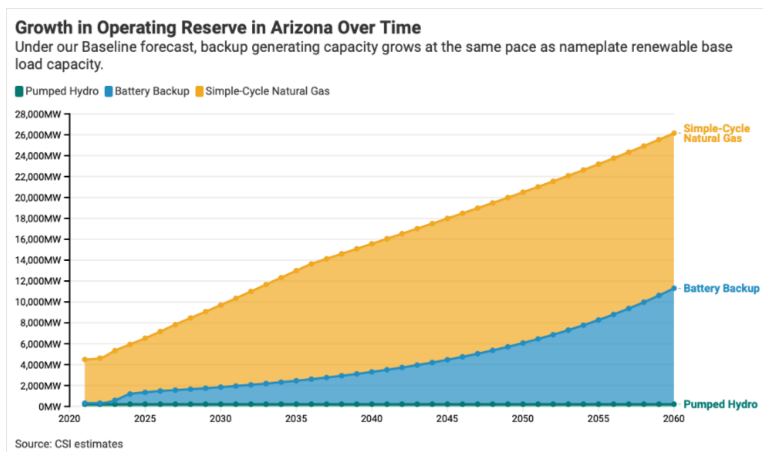

Figure 16

Industry estimates on the amount of backup capacity needed vary, but the experience in jurisdictions like Texas and many states in Europe are illustrative. It appears that sustained periods of very little or no practical output from a regions wind and solar facilities can occur with relative regularity. For example, between June 22 and July 5, 2023, electricity output from Texas' wind generators varied between 5% and 70% of nameplate capacity, even as it averaged about 18.1%[xliv]. This was *without* any notable extreme events over the period. If wind and solar generation are relatively regionally isolated and/or marginal sources of electricity, then the need for backup capacity can be mitigated through increased imports[xlv]. However, as more jurisdictions increase their own reliance on intermittent sources (subject to regional weather patterns), almost by definition import availability must fall and dependency on backup capacity must rise (the costs of moving electricity increase with the square of the distance traveled, placing economic limits on how electricity can be sourced from outside the regional weather area, and as more regions adopt intermittent renewables the reliability of imports falls in series with the reliability of domestic production itself).

The 'stress-test' scenario we posit to model utility demand for backup capacity assumes a period where instantaneous demand is 130% of its annual average ('peak demand'). It further assumes that wind and solar output are 0% of their nameplate capacities, while the systems other base-load providers (nuclear, hydroelectric, and coal) continue to operate at their operating averages. Natural gas sources (both combined-cycle and the backup sources) are assumed to operate at 70% of nameplate capacity, while batteries and pumped storage operate at 45% capacity factors (a respective theoretical maximum level for both). We then assume sufficient battery, pumped storage, and simple-cycle natural gas capacity to meet demand without load shedding during the instantaneous event. Alternative specifications that rely on more or less redundant capacity are possible and affect the assumptions made here.

Our assumption is an abstraction meant to capture the need for operating reserve, minimize the number of technical assumptions made, and simplify the problem of trying to identify practical real-time lower limits on potential wind and solar power generation in Arizona and coincident energy demand. In practice, actual ratios of redundancy will vary depending on numerous factors, including but not limited to:

- **Risk Tolerance:** Given supply intermittency introduces uncertainty into the grid, some degree of mitigation through redundant backup capacity that is idle much of the time becomes necessary. How much depends in part on risk tolerance – for example, does our system accommodate a 100-year event, or 50-year?
- **Wind & Solar Variability:** During periods of output minima (subject to the risk window defined above), what is the practical expected output from the state's intermittent renewable sources? To the extent that value is greater than zero the need for reserve capacity is reduced.
- **Demand Variability:** Similarly, when these periods of output minima occur, is demand systematically different from average? For example, if weather-related events that limit

renewable output occur predominantly at night – when demand is lower – one could operate with reduced reserve capacity.

Notes on Baseline Energy Demand Growth

Demand for energy from electricity, natural gas, and motor vehicle fuel in Arizona in 2021 is available from the Energy Information Association[xlvi]. Given population estimates available from the Arizona Office of Economic Opportunity and the U.S. Census Bureau, we can estimate current year per capita energy needs by fuel type in terms of MWh. We can further estimate future population and economic growth.

Baseline electricity demand in Arizona is projected as the sum of Residential demand (which by assumption grows at the rate of state population) and non-Residential demand (commercial and industrial demand, which grows at the rate of state RGDP). Efficiency losses are assumed fixed at 3.8% of gross output (though arguably losses would increase with renewable adoption as the grid and transmission distances grow larger). The export share of gross generation is assumed exogenous and grows at the rate of the simple average of U.S. population and RGDP growth. We assume that the state will need to construct sufficient new generation sources to maintain the same ratio between nameplate generating capacity and output as observed in the state over the past five years (under the *Baseline* scenario) but adjusted for the capacity factor of the exclusively wind and solar mix of new construction (relative to the relatively higher effective capacity factor of the existing generating mix).

Notably, this Baseline assumption assumes roughly contemporary per-capita electricity demand over time. This excludes both efficiency improvements, and electrification. **If the private transportation grid shifts dramatically towards electric vehicle over the next 30 years, future residential electricity demand could be significantly higher per-capita than in the past.** In this case, our Baseline would understate future electricity demand, and therefore understate capacity needs and cost and reliability implications.

Generator type of **net-new base-load** capacity additions is fixed at the 10-year average share of new carbon-free capacity additions in Arizona over the 2010-2021 period (roughly 15% wind and 85% solar). As discussed in the notes above, operating reserve capacity grows at a rate sufficient to maintain supply and demand equilibrium under the 'stress test' scenario. Based on trends observed in Arizona since 2018 and EIA planned additions[xlvii], battery capacity is expected to grow rapidly over the next five years, before slowing to a steady-state market growth rate of 6.6% annually due to technology, cost, and resource constraints. Remaining *Baseline* demand for operating reserve is expected to come from natural gas – the supply of which peaks at 18 GW in 2050.

Notes on Electricity Cost by Source

To estimate the costs of Arizona's energy transition under each scenario, we must consider both demand-side changes and the cost of new supply-side capacity additions. To do so, we rely on the EIA's Levelized Cost of Energy (LCOE) estimates from March, 2022[xlviii]. By assumption, we hold these costs constant across the model timeline.

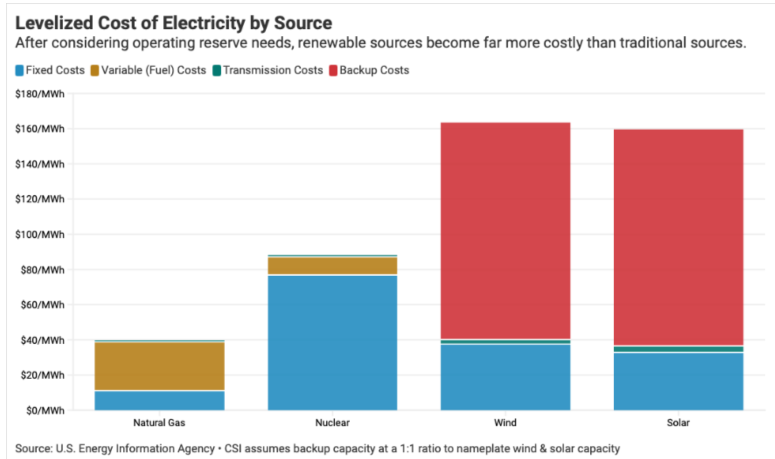

Figure 17

These figures allow us to estimate the net-present value of the combined cost of electricity by generation source, net of capacity factor (that is – to estimate nameplate plant cost, rather than effective cost per unit of output). Our key finding is that – relative to other sources – the need for operating reserve imposes significant new costs on the electrical grid that increase over time as the share of electricity from renewable but intermittent sources rises. These costs are sufficiently high to more than offset the primary value proposition posed by renewables (the absence of variable fuel costs), *given our assumptions about the necessity of backup capacity* (Figure 17). A state or utility can lower these costs by reducing its reserve capacity but that comes with reliability risk – creating an inherent cost-reliability trade off in an intermittent-dependent system. Our approach assumes backup capacity is added at sufficient rate to meet demand under a scenario where instantaneous output from wind and solar sources falls to zero; this assumption exposes ratepayers to investment costs and requires utilities to invest in and maintain generating capacity that is idle much of the time.

For simplicity, this paper assumes a constant 20-year expected or financial asset life for new generating technologies irrespective of type; that existing capacity is replaced with an equivalent source at the end of its useful life (subject to the exceptions already mentioned); and that (in constant dollar terms) current capital, fuel, and other costs are fixed over the forecast period; that there is no other source of exogenous cost growth (or decrease); and that there is a 3% discount rate. Additionally, we assume a fixed return on equity (profit) for utilities on their new investments of 8.7%[xlix], which is passed onto ratepayers, as well as a constant 3.8% efficiency loss rate.

All power sources except natural gas are assumed to provide net electricity to the grid at a fixed rate (based on an historical average of actual capacity factors in Arizona). Combinbed-cycle and simple-cycle natural gas provide remaining residual electricty needs, subject to two constraints:

combined-cycle plants cannot by assumption operate at greater than 70% capacity factor, and simple-cycle plants cannot by assumption operate at less than 3% capacity factor[l].

Obviously, these are simplifying assumptions. In practice, many states – not just Arizona – will be simultaneously competing to construct new wind, solar, and natural gas generators in the coming decades. This competition may create supply constraints that inflate the costs of these projects over time higher than today (relative to baseline general price inflation)[li]. And the resource intensity of renewable sources extends to real estate – natural gas, solar, and wind sources are all more land-intensive than the nuclear and coal systems they replace (Figure 18)[lii]. As land

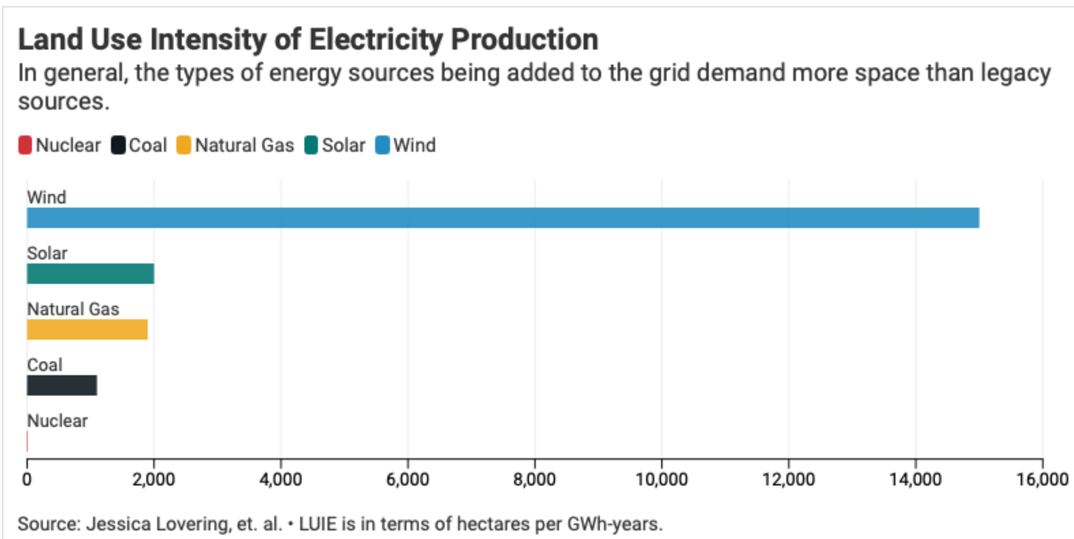

Figure 18

prices rise due to general resource competition actual costs of the contemplated energy transition may end up increasing faster than anticipated.

Baseline Model Calibration Assumptions

Electricity demand is assumed to grow with population (Residential) and GDP (non-Residential). All input prices are constant at 2021 levels.

Generation Technology	Capital Cost ($/MW)	Fixed O&M Cost ($/MW-y)	Variable Costs ($/MWh)	Tranmissio Costs ($/MWh)	Capacity Factor	Simple AZ LCOE ($/MWh)	Model Constraint	Stress-Test Assumption (% of capacity)
Combined-Cycle Natural Gas	$1,131,500	$13,765	$27.77	$1.14	50%	$49.00	Existing 2021 natural gas capacity assumed to continue in perpetuity. Existing units are maintained or replaced but no net-new generating capacity added.	70%
Nuclear	$6,778,000	$113,405	$10.30	$1.08	92%	$82.00	Existing 2021 nuclear generation capacity assumed to continue in perpetuity.	92%
Wind	$1,718,000	$27,570	$0	$2.63	25%	$68.00	15% of new base load capacity demand assumed solar; base load demand growth is a function of population & GDP growth.	0%
Solar	$1,327,000	$15,970	$0	$3.52	28%	$46.00	85% of new base load capacity demand assumed solar; base load demand growth is a function of population & GDP growth.	0%
Simple-Cycle Natural Gas	$1,365,667	$20,400	$45.83	$9.89	17% avg.	$131.00	Capacity increases as a residual after other backup capacity grows, as needed to maintain 1:1 ratio of renewable:backup sources. Utilization floats as needed to maintain sufficient supply to meet electricity demand; variable fuel & transmission costs passed onto ratepayers.	70%
Battery	$1,316,000	$25,960	$24.83	$10.05	7%	$221.00	Capacity increases to 1.26 GW by 2024. Capacity thereafter grows 6.6%/year in perpetuity. Utilization assumed fixed at 7% of nameplate capacity.	45%
Coal	n/a	$5,071	$23.67	$1.12	85%	$30.50*	Capacity falls by 7% of 2021 installed capacity / year to zero (by 2036). Capital costs are assumed sunk; utilities and ratepayers recapture operating savings as existing capacity is retired.	52%
Other	n/a	n/a	n/a	n/a	52%	$64.27	Capacity falls by 2% of 2021 installed capacity /year. Existing pumped hydro storage assumed fixed. Declines in 'Other' generating capacity attributable to a combination of reduced investment (favoring gas and renewables instead), and declining availability of Colorado River resources for hydroelectric generation.	52%

* Since Coal generation is - by assumption - only being retired and not built, we assume utilities can recapture operating costs, and capital costs are sunk. For purposes of estimating the potential utility & ratepayer savings from early retirement of coal capacity, we include only operating & variable costs and no capital costs.

Figure 19

Baseline Scenario: Capacity & Cost Implications

All else equal, Arizona's electricity grid will become more dependent on wind and solar (but also nearly 90% carbon-free and two-thirds renewable); primary backup capacity will come from traditional, fossil-fuel-based sources; and retail electricity prices will rise. Indeed, this assumption about backup sources being predominantly natural gas is significant: 74% of the state's backup generating capacity in 2050 comes from simple-cycle natural gas plants under the *Baseline*.

Arizona's Grid Composition Over Time

Under the Baseline scenario, the grid becomes more reliant on renewable and carbon-free sources over time, but at a cost of higher electricity rates and increased reliability risk.

Baseline Scenario	2021	2035	2050
Generating Capacity	27.6 GW	58.8 GW	84.6 GW
Reserve Capacity	4.49 GW	14.4 GW	23.8 GW
Carbon-Free Share	42.9%	77.3%	87.0%
Renewable Share	7.7%	50.7%	66.6%
Stress-Test Instantaneous Demand (130% avg)	16.1 GW	20.5 GW	25.6 GW
Stress-Test Instantaneous Capacity (0% wind/solar)	16.6 GW	21.2 GW	26.4 GW
Hypothetical Stress-Test Surplus/(Shortfall)	0.50 GW	0.64 GW	0.80 GW
Average Retail Electricity Rate (2021 Dollars)	10.73 ¢/KWh	13.63 ¢/KWh	15.77 ¢/KWh

Source: CSI estimates

Figure 20

Again, we take as given that the Arizona energy economy is gradually transitioning away from coal towards a combination of renewable and carbon-free sources for base load electricity generation. By 2035 coal is providing less than 0.5% of the state's annual demand for electricity under the *Baseline*, while natural gas provides 22% (from 12% and 45% respectively in 2021); by 2050 the state is projected to have no remaining utility-scale coal generation and just 13% of demand is assumed met by natural gas plants. Further, electricity demand is likely to grow going forward, given general trends towards increased electrification and growth in the state's population and economy. Our *Baseline* accounts for this demand growth but assumes no widespread above-trend electrification of the economy (e.g., vehicle travel).

This transition imposes grid costs that will raise the price of electricity for the state's electric consumers in the coming decades. For reference, according to EIA data, Arizona ratepayers were charged an average 10.73 ¢/KWh in 2021 for electricity, and preliminary data (from April 2023) suggests average rates in 2022 had already increased to 11.17 ¢/KWh. Systemwide these one-year rate increases impose $490 million in costs on electricity consumers.

To accommodate *Baseline* demand for renewable generation and backup power supply, utilities would need to make nearly $84 billion in new capital investment in generating technology by 2050. This does not include the cost of supporting infrastructure needs (transmission and distribution lines, for example). The costs of these capital investments – along with associated annual operating and maintenance costs of the generators – are passed onto ratepayers.

We estimate these cumulative costs at approximately $30.6 billion by 2035, increasing to approximately $127 billion by 2050. Electricity rates rise to 15.77 ¢/KWh (+47%) in constant 2021 dollars. Per-capita electricity expenditures in Arizona would rise from $1,300/year in 2021 to $2,300/year in 2060 (+78%) – again, all figures in constant 2021 dollars. Assuming constant household demand, an typical Arizona household consuming the same amount of electricity in 2050 as today would face an annual electricity bill of $2,581 (versus $1,756 in 2021).

Generating capacity in Arizona rises from 27.6 gigawatts in 2021 to an estimated 84.6 gigawatts in 2050, to satisfy an electricity demand of just over 19.6 gigawatts (Figure 19). The balance is excess capacity which exists to buffer intermittent sources and sustain the smooth and efficient operation of the overall grid. Note again the amount of building required to maintain a healthy grid with a significant wind and solar base load – the ratio of nameplate supply to demand rises from 2.2 times today to 4.3 times in 2050.

Under this scenario, the state's reserve capacity in 2050 is 24 GW. This is a combination of batteries (3.1 GW in 2050, up from 97 MW today), pumped storage, and natural gas generators (16.4 GW). Under a stress-test event where instantaneous combined output from the states wind and solar sources is zero, natural-gas facilities operate at 70% of nameplate capacity, and batteries operate at 45% of nameplate capacity, the state would be able to meet 130% of average instantaneous demand. For perspective, in Texas during the 2021 winter storm, instantaneous generation fell to 97% of its 2021 annual average on the evening of February 15 (43.5 GW, when wind and solar generation fell to 2% and 0% of capacity, respectively), while demand peaked at 69 GW (154% of annual average instantaneous demand)[liii].

Nuclear falls to 20% of annual electricity *generation* (6% of nameplate capacity) but otherwise remains a significant contributor to Arizona's electricity portfolio through presumed continued extension of Palo Verde's operating licenses at current capacities. Thanks to the maintenance of this large nuclear base load, the grid becomes increasingly carbon-free over time – 87% of actual electricity used in 2050 would come from wind, solar, nuclear, and other carbon-free sources (again under the *Baseline* and assuming no further interventions in the market beyond trends already occurring since 2000). Absent this nuclear base load, the state would need significantly more wind, solar, and redundant capacity (which would increase costs and reduce reliability), or more natural gas (which would reduce the carbon-free share of its electricity use portfolio). These investments would carry high costs, reduce the state's carbon-free share of electricity generation, and reduce grid reliability and efficiency.

To accommodate this *Baseline*, the state must overbuild generating capacity relative to electricity demand. While it has always been true that grids have needed to maintain a ratio greater than one of nameplate generating capacity to average demand for various reasons (grid reliability, demand fluctuations, natural output volatility due to planned and unplanned outages of individual generators, etc.), the increasing natural reliance of the Arizona and U.S electric grids on intermittent sources over time requires greater overbuilding than historically. This is a significant contributor to the significant electricity ratepayer cost increases born over the 30-year transition period, and not (as one might have expected) the generation of new wind and solar generators themselves. Policymakers should be prepared to support the expansion of grid generating capacity faster than demand and recognize the need of utilities to recoup those expansion costs through rate increases. The alternative is reduced grid reliability and an unprecedented increase in the variability of retail electricity availability.

More than 80% of the state's grid supply for backup generating capacity comes from natural gas sources. The balance comes from utility-scale batteries, with only a small share coming from pumped storage solutions. We assume supply constraints limit battery growth, necessitating reliance on fast-cycling natural gas plants over the forecast period.

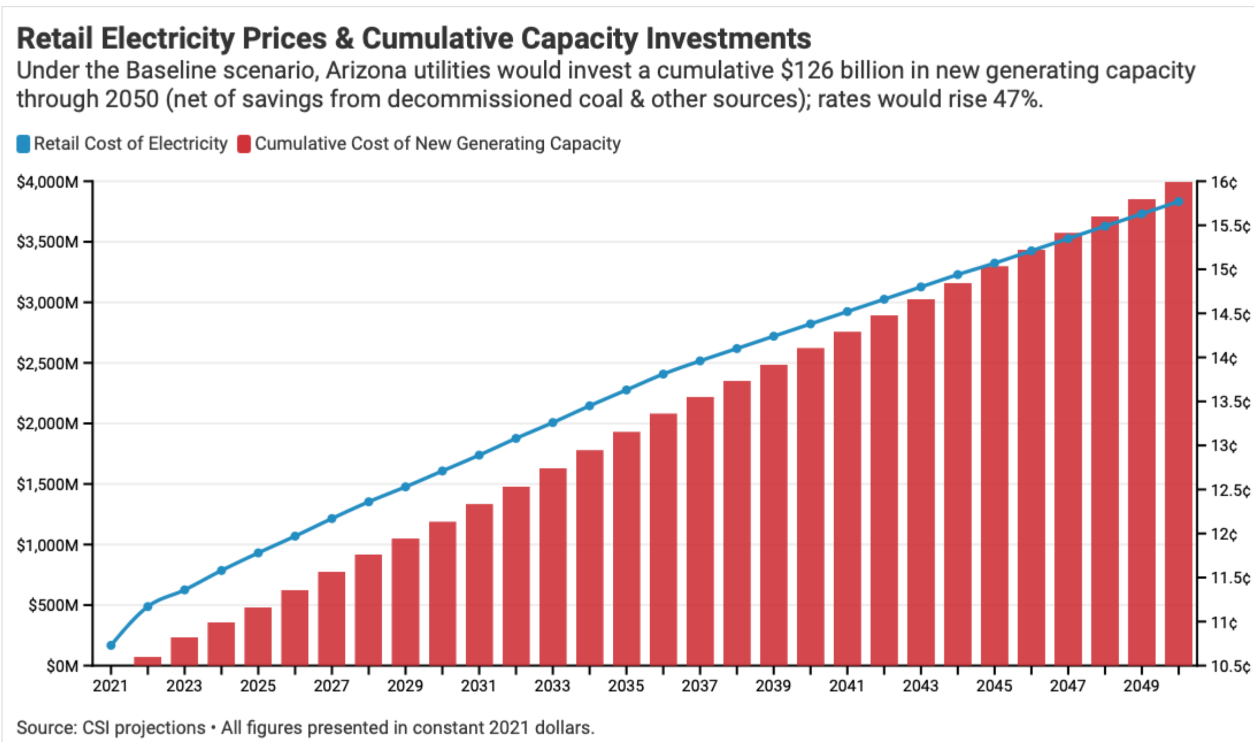

Figure 21

Conclusion

The United States is in an ongoing energy transition that began around the turn of the 21st century and has accelerated in the last decade. This transition is characterized by reduced supply of traditional base-load generation (particularly coal, but including also nuclear, hydroelectric, and other sources as well) and increased reliance on intermittent sources like wind and solar. The drivers of this are varied and substantial – public policymakers at all levels have exerted significant regulatory pressure and fiscal incentive on electricity providers; investors and consumers alike demand utility companies offer renewable options; and technological change has driven nameplate costs of wind and solar technologies down relative to other technologies.

Despite the apparently competitive "nameplate" cost of new utility-scale wind and solar capacity (e.g. gigawatt of generating capacity to gigawatt of generating capacity), this intermittency is driving demand for backup sources, which historically have come from natural gas (combined-cycle for base load, and simple-cycle for intermittent load). High cost and supply constraints limit the short-run opportunity of battery technology to fill this need at the rate needed to meet demand if the goal is to maintain reliability. Redundant backup generators add to the cost of this transition, as does the need to build a larger grid due to the lower average capacity factor of renewable sources.

In Arizona, this *Baseline* transition is expected to cost electric utilities and ratepayers over $126 billion and create a grid that is 67% renewable and 87% carbon-free by 2050. The significant investment in wind and solar sources will increase volatility in energy generation, creating massive demand for new backup sources that are idle most of the time (but support the grid when wind and solar fail to produce). The ratio of grid generating capacity to demand rises from 2.2 times to 4.3 times by 2050. Much of this capacity is idle much of the time.

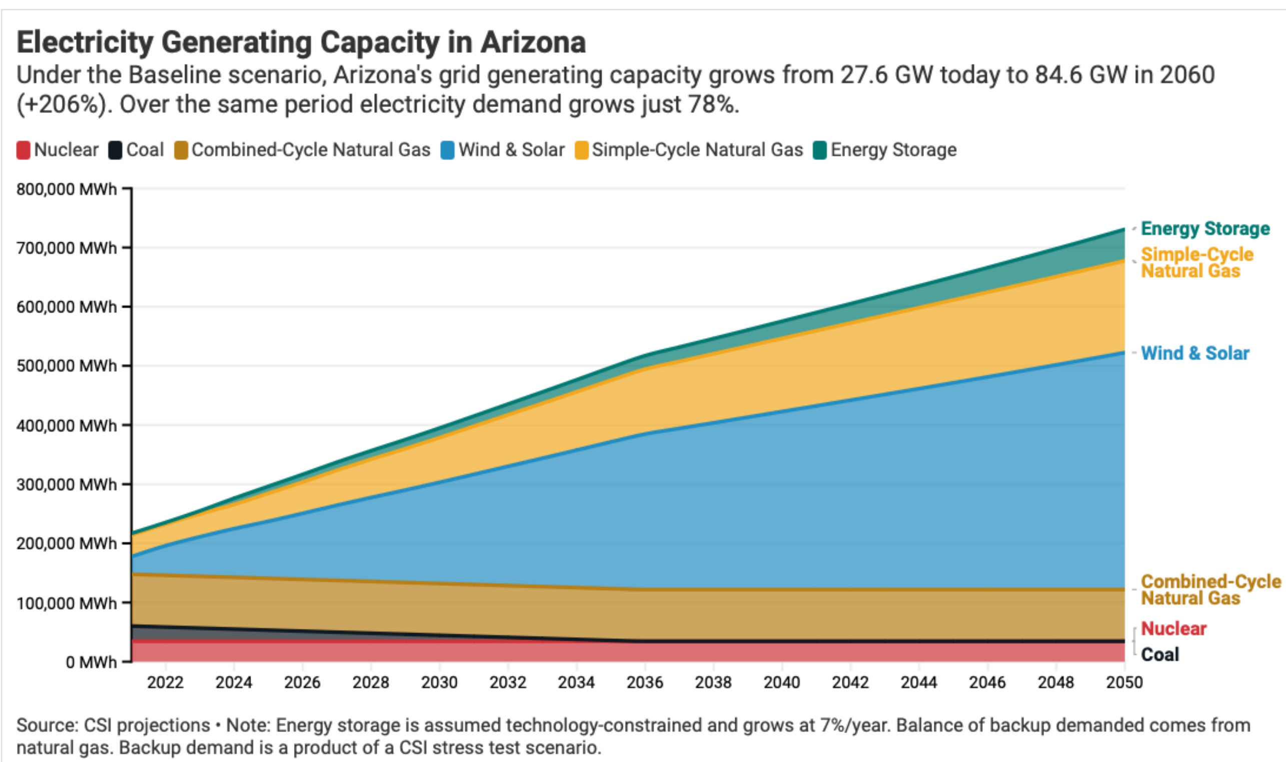

Figure 22

Under alternative scenarios where the economy is increasingly electrified (electric vehicles could *double* household electricity use) or nuclear and natural gas sources are more aggressively phased out, cost increases and reliability decreases quickly become prohibitive. CSI will explore this further and discuss those implications in our follow-up paper.

However, we hope this piece helps illuminate a central point: increasing utilization of intermittent generation sources to maintain a large electrical grid creates generator uncertainty and costs. This uncertainty can be mitigated by investing in firm and dispatchable resources – like new natural gas plants today, and in the future potentially other technologies as innovations allow. But those investments are costly and financially risky for the utility since they may not be a regular source of marketable power. **State policies and a regulatory environment that facilitate an electricity market that provides redundancy and 'all-of-the-above' resource building (while enabling utilities to recoup those costs through rate adjustments that reward risk-mitigation in addition to regular generation) become increasingly important.**

[i] Blanco, Sebastian. "Strict EPA Rules for 2027-2032 Vehicles Announced, Garnering a Range of Reactions". *Car and Driver*. April 13, 2023.

[ii] Deliso, Merethith. "Why California has blackouts: a look at the power grid". *ABC News*. September 9, 2022.

[iii] Timms, Maria. "What we know: TVA ordered rolling blackouts for the first time in 90 years amid freezing temps". *Nashville Tennessean*. December 24, 2022.

[iv] "Arizona State Energy Profile". *U.S. Energy Information Administration*. Accessed on April 21, 2022.

[v] "Arizona State Energy Profile Data". *U.S. Energy Information Administration*. Accessed on March 16, 2023.

[vi] "Arizona Electricity Profile 2021". *U.S. Energy Information Administration*. November 10, 2022.

[vii] CSI used REMI and modeled a 12.1% increase in consumer and producer electricity prices over ten years, relative to a baseline forecast.

[viii] Some sources, like *Wikipedia*, define 'base-load' capacity as the minimum level of demand on an electrical grid. Traditionally, base load has been the regular output demanded from an electrical grid from more reliable and economical generating sources that cannot or are not typically cycled up or down in response to intermittent demand (predominantly coal and nuclear). Recently, with falling natural gas prices and rising demand for renewable and alternative sources, base load increasingly looks like a combination of wind, solar, combined-cycle natural gas, and legacy coal and nuclear sources.

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