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The Power Behind Artificial Intelligence

Nat Gas, Nuclear, and Battery Storage to Fix Solar

Please refer to important disclosures on pages 25 and 26. Analyst certification is on page 25.

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Executive Summary

Demand for data center growth has been building for the past 20 years, as increasingly more processes digitize. However, until recently, this demand was manageable. The advent of large language models (AI) and first-mover incentives, as well as an "electrify everything" approach to climate change, is weakening an increasingly fragile power grid. In this report, our fourth subsector initiation in the energy and sustainability sector, we explore the U.S. power grid in depth. Our focus will center on AI demand, which is forecast to increase electricity demand anywhere from 150 TWh to 500 TWh per year in 2030, representing an unprecedented 4%-12% growth of annual electricity demand.

Why is it important to understand AI's role in data center growth and energy demand? Unlike traditional search, the parameters of large language models used for Chat GPT require much more energy. Chat GPT 3 is estimated to demand 2.9 Whr per query, while GPT 4.0 ranges between 1.2 kWhr and 1.5 kWhr. This compares to traditional search at roughly 0.3 Whr, or 0.0003 kWhr, or 10-430 times more energy per query. These models will only improve, suggesting that these are baselines versus end state. Data centers for cryptocurrency or blockchain pose an equally daunting demand scenario. According to CoinDesk, every Bitcoin transaction consumes roughly 1,000 kWhr of electricity, whereas a Visa transaction consumes 0.0003 kWhr. Once again, this suggests a factor of 300,000 times more energy per transaction.

While technocrats will often argue that the "free" input fuels for renewables such as solar or wind push marginal costs to near zero, making variable renewable power the cheapest option to meet new demand, our data concludes the exact opposite. In fact, because of how our grid and our society is structured around dispatchable power on demand, penetration above 5% of renewables in the grid architecture quickly shifts from the least expensive to the most expensive generation asset. While battery storage helps, and will certainly be part of the solution, we conclude that the greatest near-term benefactor will be natural gas. Longer term, we conclude that advanced nuclear solutions not only must be part of the conversation, but also might be central to grid architecture.

The key takeaways for investors include the following:

- We believe the best way for investors to gain exposure to the AI power trends are to own natural gas generation assets (GE Vernova), energy storage (Tesla), and nuclear assets.

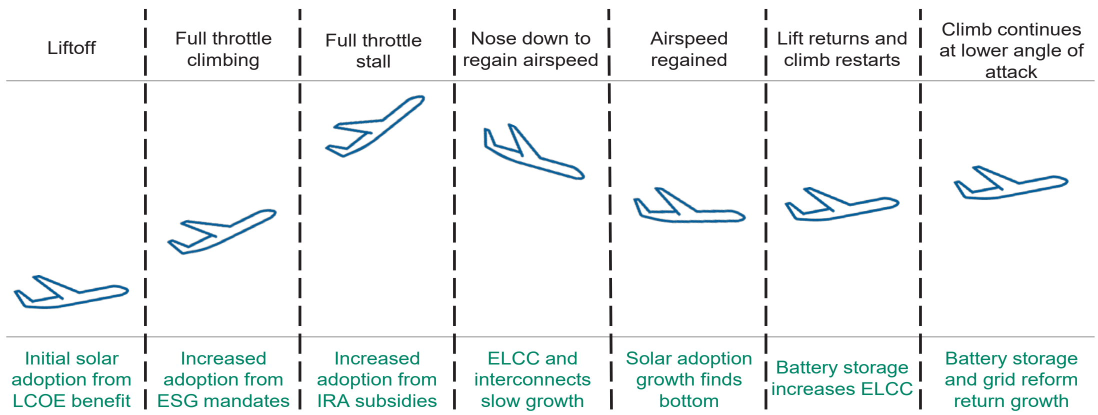
- Demand for data centers and both AI and crypto presents a compelling challenge for existing energy markets. Over 5% of penetration of renewable energy in grid systems escalates electricity costs far above expectations.

- The conventional view that solar is in a cyclical downturn due to higher cost of capital (interest rates) does not track with our analysis and is only partly true. In fact, we believe the situation is more structural than cyclical and look at how new technologies such as gallium nitride and silicon carbide might offset margin compression.

The First Step Is Acknowledging the Problem

Renewables are entering the "mid-transition" power stall. A power stall occurs in an airplane when the angle of attack is too steep and no matter how much throttle is applied, lift begins to fail. The risk is the plane falls out of the sky. However, a skilled pilot can easily correct this, but only by recognizing the signs. While counterintuitive, the corrective action is to reduce throttle, nose forward and reduce the angle of attack. Inexperienced pilots might panic and try to power out of the situation only to buttress a fatal outcome.

Exhibit 1
Powering Artificial Intelligence
Dynamics of a Power-On Stall in Solar Adoption

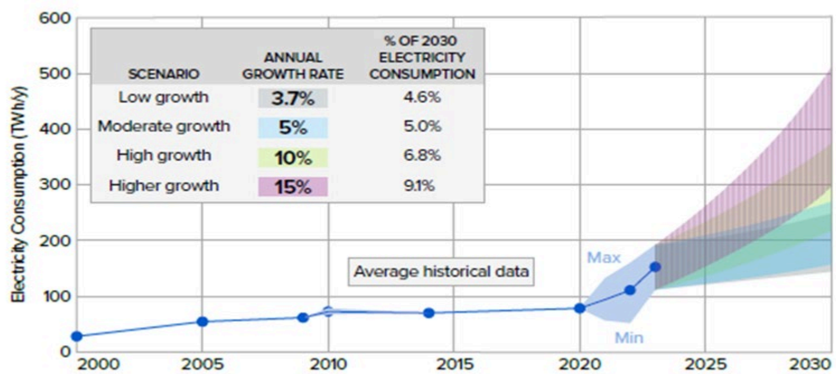


Source: William Blair Equity Research

Applying this metaphor to the energy transition is useful, particularly for renewables and grid systems. Let us assume the pilot in this example represents the policymakers/regulators, the fuel for the engines represents the subsidies, and the lift would be the economic return on the energy generated from the technology or energy return on investment (EROI). Early adoption of solar provided great lift due to low penetration of assets on the grid, subsidized capital, the ability for stakeholders to claim victory around ESG/net-zero mandates, and early placement on an "S" curve of technology adoption. However, as we detail in this report, as more solar is added to grid systems, balancing authorities (BAs) are finding that replacement of traditional generation with renewable energy is not one for one, and instead of retiring assets, they must keep legacy generation online to ensure grid reliability. Thus, counterintuitively, the cost of reliable power is increasing, particularly in high solar adoption areas. Despite this concern, and most likely because they have not identified this problem correctly, policymakers are still issuing subsidies for power production, or trying to create more lift through solar production. The plane, however, is stalling out due to these resiliency issues. Evidence of this stall can be seen in actions taken across the country, such as absurdly long interconnection queues, new net metering policies that discourage solar adoption without battery systems, power purchase agreement (PPA) deals to secure dispatchable gas power, and very high integration cost estimates as a function of solar penetration levels.

At the same time as the above problems are playing out, and for the first time in decades, electricity demand is forecast to increase in the coming years in many areas across the country, driven by the electrification of everything trend combined with a proliferation of data centers and the advent and adoption of AI (see this report from our technology analysts). The Electric Power Research Institute (EPRI) published a report called "Powering Intelligence" that forecasts the expected growth in electricity demand due to future growth in AI. EPRI estimates that electricity consumption will grow at an annual rate of 3.7% in its lowest scenario, which by itself is a large increase over the past decades of flat electricity demand. EPRI estimates that data centers will consume between 4.6% and 9.1% of total U.S. electricity consumption by 2030 (versus 4% today).

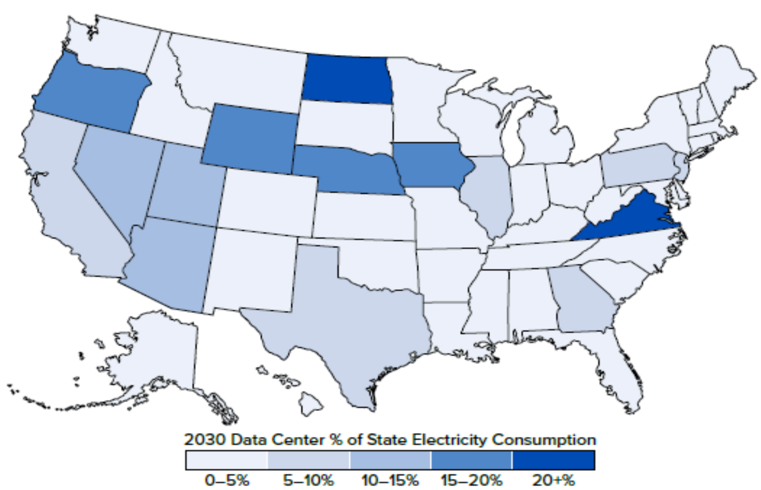
Exhibit 2
Powering Artificial Intelligence
Projected Electricity Consumption for U.S. Datacenters



Source: Electric Power Research Institute, Inc. "Powering Intelligence: Analyzing Artificial Intelligence and Data Center Energy Consumption" 3002028905 (2024)

It is also important to note that the electrical demand by data centers is unevenly dispersed. Fifteen U.S. states, according to EPRI, account for 80% of data center electrical load. Virginia leads this group, and roughly 25% of electricity consumption in the state in 2023 was in data centers.

Exhibit 3
Powering Artificial Intelligence
Projected Data Center Electricity Consumption Share per State in 2030



Source: Electric Power Research Institute, Inc. "Powering Intelligence: Analyzing Artificial Intelligence and Data Center Energy Consumption" 3002028905 (2024)

Energy Transition 101: How the Grid Works

Cost Can Outweigh the Benefit

In a grid system with 100 GW of installed capacity, the addition of a 10 MW (0.01GW) solar facility will not make much of a difference—indeed, it is a rounding error. In fact, often the first solar power in a grid system reduces the cost of power production because there are no fuel costs. But as more solar is added to the grid, the costs of integration usurp the benefits of the generating asset.

To understand why this is the case, we must first understand what is meant by "grid balancing." In its most basic form, we should think of the grid system as an interconnected bunch of wires with electrons shaking back and forth (alternating current). They shake back and forth at a specific rate—60 times per second in the U.S. This is the frequency of the grid. When demand comes on the grid, it pulls at those electrons, slowing the frequency. Conversely, when generation is added to the grid, it speeds up the frequency. Grid balancing is the role of the balancing authority (BA), and they try to make sure that the demand on the grid is met with exactly the right supply of power so that neither demand nor supply change the frequency. This is monitored 24/7, 365 days a year. In fact, frequency changes of just a percent or two can cause massive grid failures.

It is important to note that BAs cannot change demand (at least historically), so they have only the supply side (i.e., generation) to work with. Given this setup, it should come as no surprise that BAs carefully examine the amount and type of generation assets when planning the future supply of power. In broad strokes, BAs have historically tried to make sure that there is: a) ample generation to meet demand on the highest demand day of the year—this is called peak demand; and b) enough dispatchable supply to meet the fluctuations in demand throughout the day.

Natural Gas Wins the Flexibility Game

Each generation asset is a bit different, and they are therefore utilized differently in the grid. Nuclear power, for example, provides very steady baseload generation, so it helps meet demand; but it is inflexible, meaning that it cannot ramp up or down to meet demand over the course of a day. Coal generation is like nuclear—once the flywheel is turning, it cannot change easily. Natural gas generators come in a variety of assets: 1) combined cycle turbines; 2) simple cycle turbines; 3) cogeneration (combined heat and power); 4) microturbines; and 5) fuel cells. Some of these turbines are referred to as "peaker" plants. As the name implies, they can spin up and down in short periods of time, adding incremental generation relatively quickly. This makes natural gas much more flexible than nuclear or coal. Natural gas generation is therefore often used to meet demand throughout the day.

Challenges of Solar and Wind Energy

The challenge posed by variable renewable energy (VREs) like solar and wind is different still. VREs are predictable at the grid level given weather forecasting, but they are inflexible in that the balancing authority cannot ramp up generation from a solar facility if the sun is not shining. VREs are either producing power or they are not, and the grid system must manage that generation as best it can. To be sure, VREs can help to meet demand if generation happens to align with demand, but for grid resiliency and planning purposes, the balancing authority cannot rely on VREs the same way they can rely on, for example, a natural gas combined cycle generator.

To understand how each resource contributes to resiliency, many BAs calculate the effective load-carrying capability (ELCC). According to the PJM, the "ELCC provides a way to assess the capacity value (or reliability contribution) of a resource (or a set of resources)," or perhaps an easier way, the ELCC is a "measure of the additional load that the system can supply with a particular generator of interest, with no net change in reliability."

According to the PJM's calculations, thermal resources are the most reliable (ELCC = 81%), followed by demand response programs, then storage, and, lastly, variable renewable energy like solar and wind (exhibit 4). In fact, within the VRE category, fixed-tilt solar (which we will term "standalone solar" to distinguish it from solar plus battery systems) has the worst ELCC (exhibit 5). Standalone solar has ELCC values of 9% for fixed-tilt solar and only 14% for tracking solar. This means that for every 1 MW of solar added to the PJM grid, for reliability purposes, the PJM will only consider 0.09 MW added (assuming fixed tilt). However, adding battery energy storage systems (BESS) to a PV array can increase the ELCC to between 59% and 78%, depending on the duration of the storage system (exhibit 6). So, while solar by itself adds very little to resiliency, solar with BESS is almost on par with conventional thermal generation.

Exhibit 4
Powering Artificial Intelligence
PJM Resource ELCC

Resource Type	ELCC Average (%)
Thermal	81
Demand Response	76
Storage	68
VRE	35

Source: PJM

Exhibit 5
Powering Artificial Intelligence
PJM VRE Resource ELCC

Resource Type	ELCC Average (%)
Fixed-Tilt Solar	9
Tracking Solar	14
Onshore Wind	35
Offshore Wind	60

Source: PJM

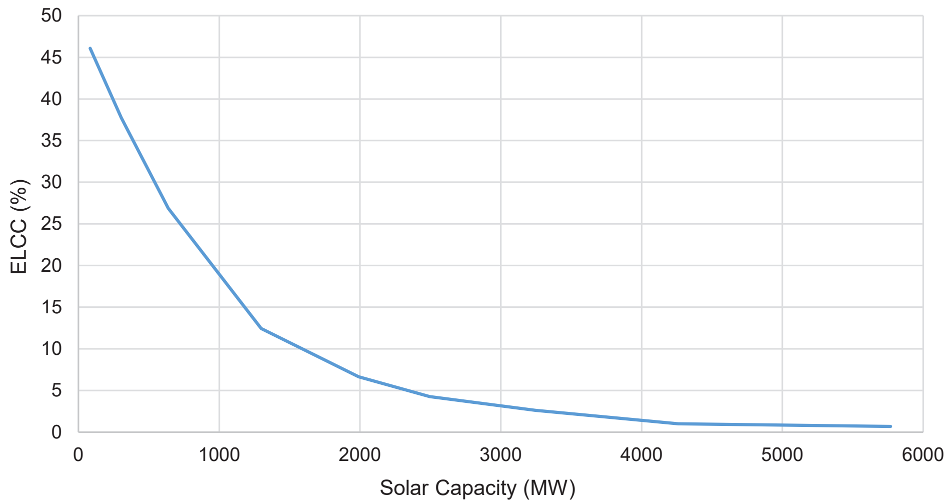
Exhibit 6
Powering Artificial Intelligence
PJM Solar Plus Battery Storage ELCC

Resource Type	ELCC Average (%)
Four-Hour Storage	59
Six-Hour Storage	67
Eight-Hour Storage	68
Ten-hour Storage	78

Source: PJM

The ELCC also tends to drop dramatically as more VREs enter a market. For example, a typical graph of ELCC will start with an ELCC near or above 50%, but as solar capacity is added to the grid, the ELCC will quickly drop (exhibit 7). The reason for this is simple—when only 1% of the grid is VREs, then the rest of the grid can easily manage cloudy days. However, a cloudy day in California, for example, where 22% of the installed capacity is solar, can result in a large drop in power production. This forces the BA in California (CAISO) to maintain enough reserve capacity to compensate for that drop. In short, the "effective" value of adding solar declines as more is added to the grid mix. See our "Case Study," on pages 20-21.

Exhibit 7
Powering Artificial Intelligence
Theoretical Cumulative Solar Capacity vs. ELCC

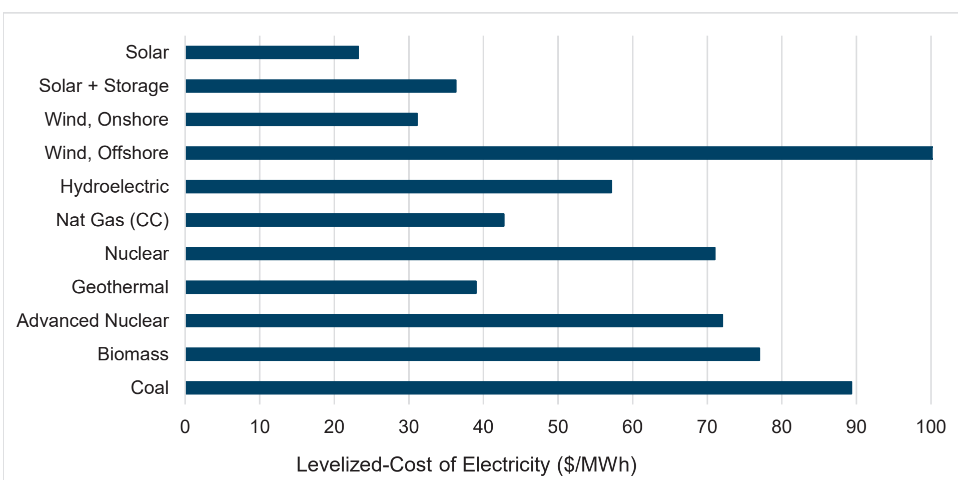


Source: Heptonstall and Gross 2021 and William Blair Equity Research

Integration Costs Are Key – LCoE Is Not the Whole Story

According to the Energy Information Administration (EIA), solar PV should be the cheapest way to produce electricity, with a levelized cost of electricity (LCoE) of $23 per MWh (exhibit 8). By comparison, coal is roughly $89 per MWh and combined-cycle natural gas units are $43 per MWh. Notably, PV-battery hybrid systems are only $36 per MWh, meaning that solar plus storage is also cheaper than gas combined cycle units, from an LCoE perspective.

Exhibit 8
Powering Artificial Intelligence
Levelized-Cost of Electricity for Various Technologies



Source: EIA and William Blair Equity Research

The LCoE estimates create a compelling narrative that solar PV is the cheapest form of electricity, which has led to policy support for massive subsidies and institutional investments. The problem is that LCoE is an academic exercise akin to studying gravity in a vacuum. LCoE is about as useful as analyzing a company using only a balance sheet, as it provides insight but in an academic and static way. Since irradiance is dynamic and changes daily, the intermittency of VREs limits the efficacy of using LCoE to justify a project from the perspective of the BA, which is primarily concerned with grid resilience.

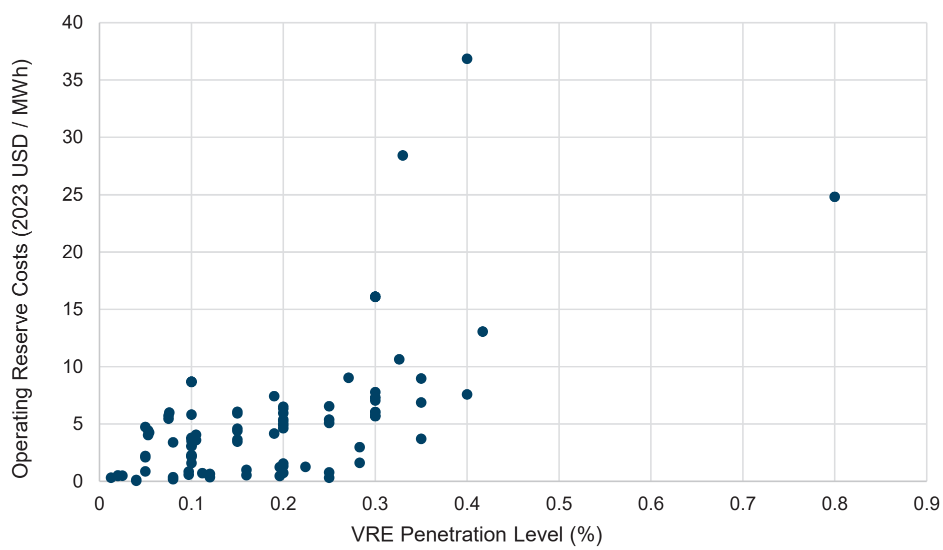
Though the PJM and other BAs across the country calculate ELCC, there is scant data on the whole-system costs associated with integrating VREs into grid systems. The reason for this is simple—the costs will vary widely based on each grid system's idiosyncrasies and because the data are rarely collected and hard to assemble. But recent data published in *Nature Energy* (Heptonstall and Gross 2021) reveals the magnitude of these costs for major European and North American grid systems.

The language of integration costs changes around the world, so the analysis focuses on four different categories: operational reserve costs, which are costs associated with balancing the grid over short timescales from instantaneous to several hours; capacity costs, which are costs associated with ensuring enough capacity is available to meet peak demand; profile costs, which are the costs associated with the mismatch between VRE generation profiles and demand profiles of a grid system, and include a variety of mechanisms used to balance grid systems, such as demand response programs, energy storage, and additional balancing resources (i.e., additional reserves); and aggregate costs, which try to encapsulate all the costs mentioned previously.

- The measures of integration costs include operating reserves, capacity costs, profile costs, and aggregate costs, and all of them increase as more VREs are added to the grid.

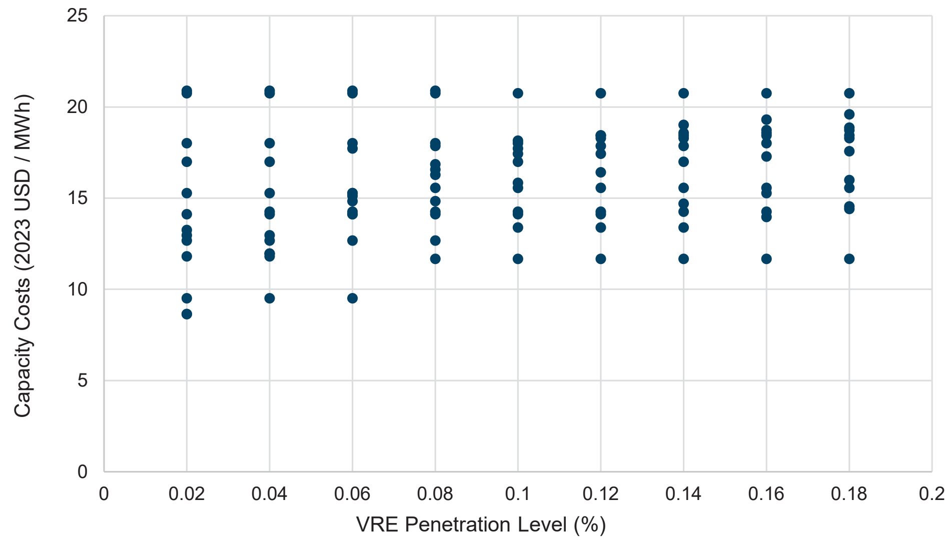
- The magnitude of the costs can range from a few dollars to over $100 per MWh of capacity.

Exhibit 9
Powering Artificial Intelligence
Operating Reserve Costs vs. VRE Penetration



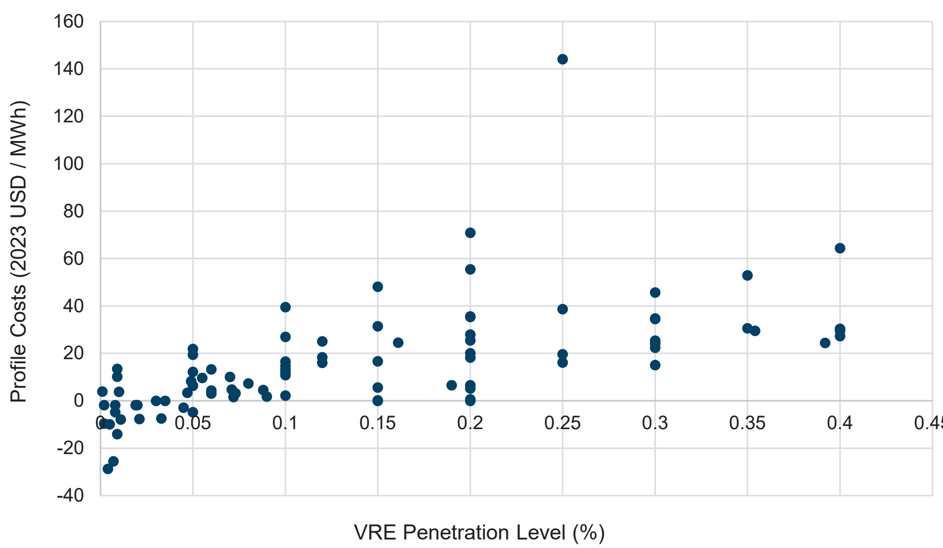
Source: Heptonstall and Gross 2021

Exhibit 10
Powering Artificial Intelligence
Capacity Costs vs. VRE Penetration



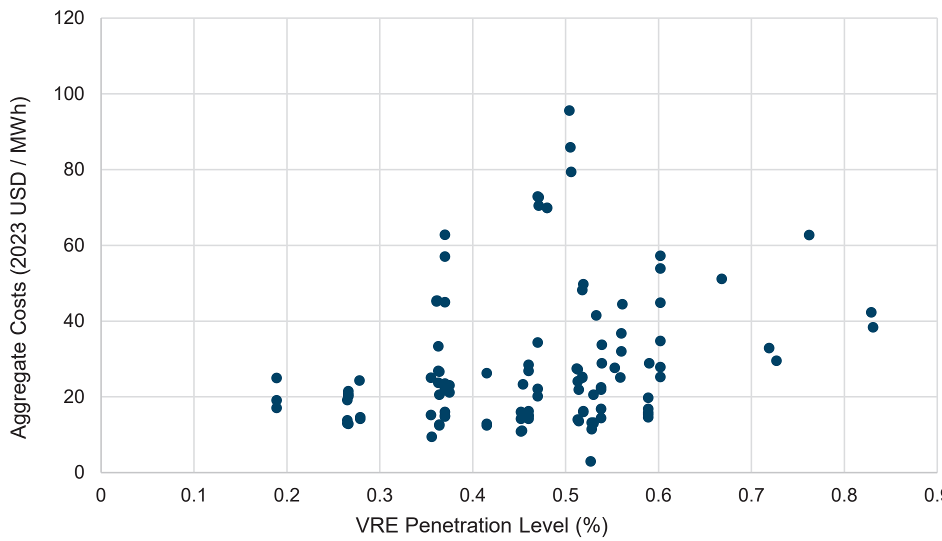
Source: Heptonstall and Gross 2021

Exhibit 11
Powering Artificial Intelligence
Profile Costs vs. VRE Penetration



Source: Heptonstall and Gross 2021

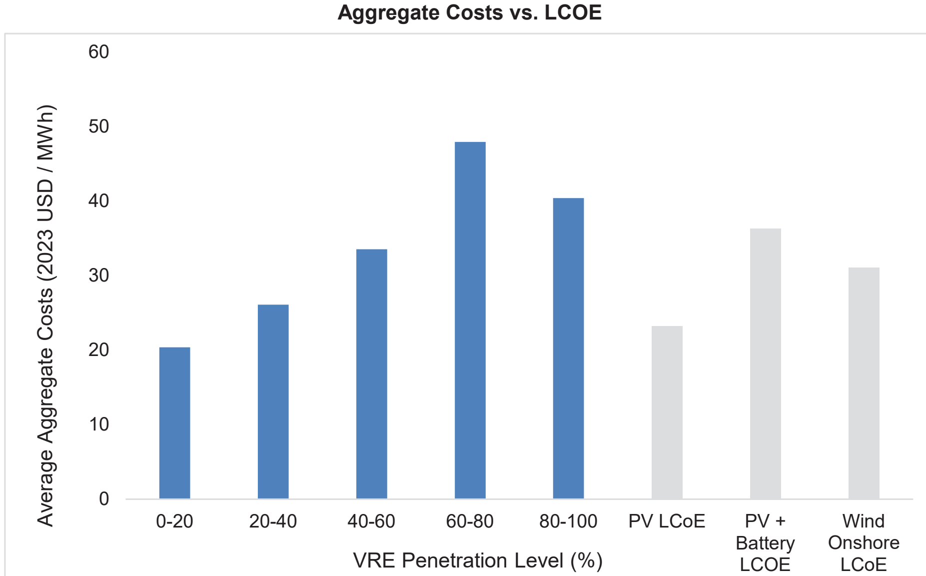
Exhibit 12
Powering Artificial Intelligence
Aggregate Costs vs. VRE Penetration



Source: Heptonstall and Gross 2021

There is a wide range of values depending on the penetration level of VRE in a specific grid system. Filtering the aggregate costs data and focusing on the solar and solar plus storage projects in Europe shows the magnitude of the integration costs across Europe. Even at very low penetration rates, the presence of VREs on the grid system leads to costs in the range of $20 per MWh to $50 per MWh at higher penetration levels. This means that integration costs are greater than the LCoE costs in grid systems with higher solar penetration levels.

Exhibit 13
Powering Artificial Intelligence
Aggregate Costs vs. LCOE



Source: Heptonstall and Gross 2021

Early Evidence Points to Gas and Solar Plus Storage; Nuclear Long Term

The exact solution to meet increasing demand and ensure grid resiliency will vary in each BA, because the demand profile, generation mix, and existing electricity market structure is different in each BA. But, if one dives into the integrated resource plans (IRPs) for some of the utilities that are grappling with these issues right now, some trends emerge:

1. BAs will try to secure gas generation as a flexible source that can be used for grid balancing and that has the lowest GHG emissions of all fossil combustion.

2. BAs will add battery storage systems to existing solar and wind projects, and then build new solar plus storage. Solar by itself will be discouraged.

3. Nuclear will emerge as a long-term solution as countries around the world turn to it to meet increasing demand.

Gas and Solar Plus Storage

The evidence is piling up that BAs are moving to gas and storage to ensure future grid reliability. The Electric Reliability Council of Texas (ERCOT), which manages about 90% of the electricity demand in Texas, produced a Long-Term System Assessment in January 2023 that states explicitly, "significant growth of inverter-based resources (IBR) [IBR = renewable energy, mostly wind and solar] and more advanced natural gas generation with higher efficiencies than today's conventional generation technology was observed across all three scenarios." The report goes on to state that "retired coal and natural gas generation was replaced by renewables, new natural gas generation, and battery energy storage."

These trends are further reinforced by moves from Georgia Power and Duke Energy in the Southeast. As shown in exhibit 14, Georgia Power has increased its demand forecast by 7% over the next few years, which equals roughly 1.1 GW of new power. The updated 2023 IRP from Georgia Power proposed to meet this newly revised uptick in load demand with 2.4 GW of conventional thermal generation and 1 GW of BESS.

Exhibit 14
Powering Artificial Intelligence
Georgia Power Integrated Resource Plan

	Project Size (MW)	Project Category
PPA between Georgia Power and Mississippi Power	750	Gas and/or Coal
PPA between Georgia Power and Santa Rosa Energy Center, LLC	230	Gas
Authority to Develop, own and operate BESS at various sites	1,000	Battery Energy Storage Systems
Authority to Develop, Own, and Operate three simple cycle CTs at Plant Yates	1,400	Gas
Two new customer-sided DER programs	unclear	DER
Total	**3,180**	

Source: Georgia Power

The story from Duke Energy is similar to Georgia Power. Facing near-term increases in load growth, it adjusted its energy generation to favor gas (exhibit 15). The original near-term action by Duke called for 6 GW of new solar and 2.7 GW of new BESS, and 5.7 GW of gas. Duke Energy's supplemental adjustment plan, which was proposed after the demand forecast was increased, in part due to expected growth in AI data centers, added only 0.46 GW of solar but another 3.1 GW of gas. In other words, gas is being viewed as the solution to increasing demand.

Exhibit 15
Powering Artificial Intelligence
Duke Energy Integrated Resource Plan

Original Near Term Action Plan	Supplemental Adjustments Given new Load Forecasts	% Change
6,000 MW Solar	460 MW	7.60%
2,700 MW BESS	0 MW	0%
4,080 MW Combined Cycle (Gas)	2,720 MW	66%
1,700 MW Combustion Turbine (Gas)	425 MW	25%

Source: Duke Energy

How Does Nuclear Fit In?

Nuclear power production is a perfect match for the electricity needs of data centers since data centers need a steady, and large, supply of electricity, and that is exactly what nuclear facilities provide. However, there is a time mismatch between supply and demand. The demand from data centers will come within the next decade, while a new electricity supply from nuclear will take at least a decade. We see new nuclear as a long-term play.

As a result, existing nuclear will be in high demand to enter long-term PPA deals directly with data center off-takers. For example, Talen Energy, the owner of 2,228 MW of nuclear power at the Susquehanna Nuclear Facility in Pennsylvania, is entering into a $650 million PPA to sell power directly to Amazon Web Services, which is co-locating with the power facility. This type of co-location and long-term PPA will become increasingly appealing in the short term as AI data centers look for secure, stable, and large power supplies.

Nuclear is increasingly being sought by countries around the world, apart from both Germany and the U.S. However, that sentiment seems to be changing in the U.S. According to data in the McCoy Power Reports, China, Poland, India, and Ukraine all anticipate GW-level nuclear capacity addition in the next decade. As of now, the U.S. has requested only 17.5 MW. As power demand grows in the future, a nuclear renaissance could occur in the U.S.

Exhibit 16
Powering Artificial Intelligence
Announced Nuclear Reactor Capacity Additions

Country	Number of Units	Capacity (MW)
China	8	9420
Poland	5	6550
India	2	1400
Ukraine	1	1100
Russia	11	715
Canada	2	400
USA	2	17.5
South Africa	1	8.5
South Korea	1	5

Source: McCoy Power Reports

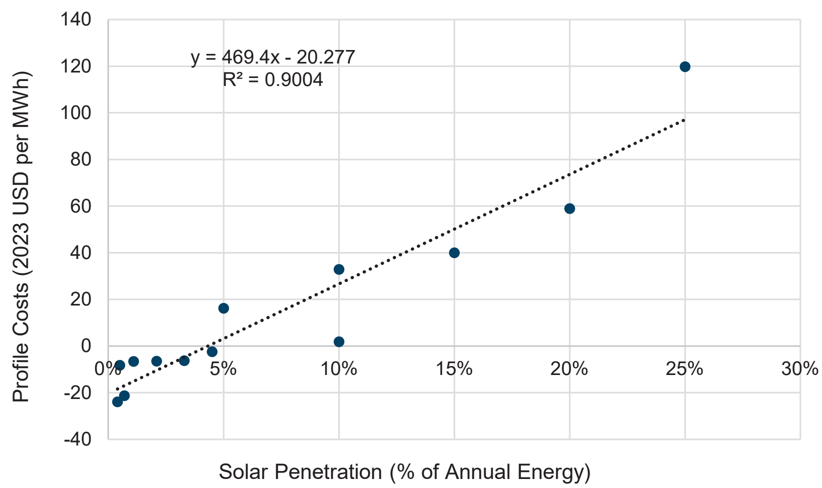
Estimating the Cost of Grid Resilience During the AI Boom

The key takeaways from our analysis are as follows:

- The profile costs—that is, the whole system cost—of adding solar to grid systems increases quickly as solar penetration levels exceed the threshold of 5% capacity.
- If low growth forecasts from EPRI become reality in 2030, then Midcontinent Independent System Operator (MISO) and PJM will have relatively low whole-system costs by using solar plus storage to meet new demand.
- The MISO is best positioned to accommodate new solar plus storage to meet new demand, and the CAISO is the worst positioned. The MISO will see savings of $7.86 per MWh by installing solar plus storage systems, while the CAISO could see costs over $100 per MWh by installing additional solar plus storage systems.
- Due to the very low ELCC of 9% for solar standalone systems, the profile costs associated with meeting new demand are roughly the same and often exceed the LCoE costs of installing the solar system. If the higher demand scenario becomes a reality, then the cost of solar standalone will be prohibitive as every BA exceeds the 5% solar threshold.

Calculating the cost that AI will have on power systems is complex, but by combining several different data sources, we have put together the first estimates of the whole system cost of AI to the electricity system. Whole system costs combine both LCoE costs and grid resiliency costs to determine the total cost—or whole system cost—of the energy transition. Generation costs were taken as the levelized cost of electricity, as calculated by EIA. Estimates for the cost of grid resilience were taken from profile cost data published by Heptonstall and Gross (2021). Profile costs are the costs associated with the mismatch between VRE generation profiles and demand profiles of a grid system. This includes costs associated with a variety of mechanisms used to balance grid systems, such as demand response programs, energy storage, and additional balancing resources (i.e., additional reserves). We focused this analysis on solar, and the best data available at the time of this publication was from Germany (exhibit 17). While applying this to the U.S.-based system is not perfect, the similarities and high correlation of the data (R2) suggest its efficacy in determining direction and magnitude.

Exhibit 17
Powering Artificial Intelligence
Solar Penetration and Profile Costs



Source: Heptonstall and Gross (2021), EIA, and William Blair Equity Research

Profile costs increase quickly as the capacity of solar on a grid system increases past a threshold at roughly 5%. In other words, at penetration levels below 5%, solar actually saves money, because the LCoE of solar is low and the penetration levels are so low that the impact to resilience is not present.

To get an estimate of the whole system cost of AI, we first calculated the solar penetration percentages for five large balancing authorities that account for over half of the U.S. electricity production and span from coast to coast—PJM, MISO, CAISO, ERCOT, Southern Company (exhibit 18). The MISO and PJM are below the 5% threshold, while CAISO, ERCOT, and Southern Company are all above.

Exhibit 18
Powering Artificial Intelligence
Solar Penetration per Balancing Authority in 2023

Balancing Authority	Solar Penetration
PJM	3%
MISO	2%
CAISO	22%
ERCOT	13%
Southern Company	8%

Source: PJM, MISO, CAISO, and Southern Company

We then calculated the increase in electricity required to meet AI demand according to the EPRI report, also by balancing authority. We calculated the increase in demand for all scenarios presented by EPRI: low growth, moderate growth, high growth, and higher growth. The PJM is projected to have the largest increase in load due to AI. The ERCOT is the second largest, followed by the CAISO, then MISO, and lastly Southern Company.

Exhibit 19
Powering Artificial Intelligence
Projected Load Growth Scenarios per Balancing Authority

Balancing Authority	Projected Load Increase (GWh/yr)			
	Low Growth	Moderate Growth	High Growth	Higher Growth
PJM	13,045	19,106	46,673	71,400
MISO	3,300	4,791	13,432	21,549
CAISO	4,701	6,803	16,932	24,925
ERCOT	6,338	8,819	20,696	29,946
Southern Company	1,795	2,509	5,860	10,190

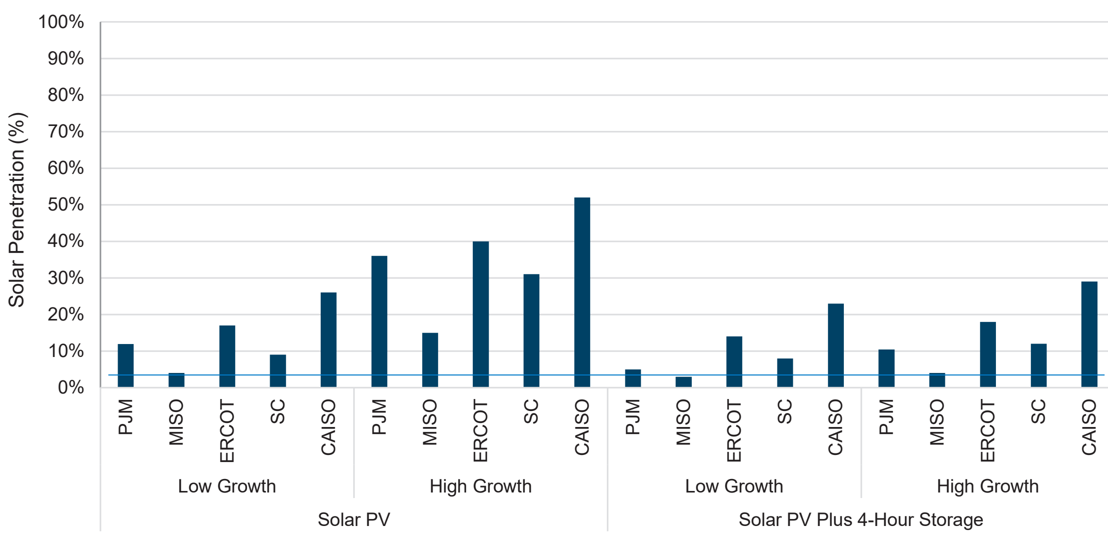
Source: William Blair Equity Research

As described earlier in this report, each generating asset is valued differently by the BA, measured as the ELCC. We estimated the increase in capacity required to meet new AI demand factoring in the ELCC for solar in each BA. For example, the PJM in the low-growth scenario will see an increase of 13,045 GWh/year in 2030. Standalone solar PV has an ELCC of 9% in the PJM. So, if all the 13,045 GWh/year were to be met by solar, the capacity required would be 16 GW, which is calculated as follows:

New Capacity (GW) = (Projected Load Increase GWh/year)/ (8,760 hours/year * ELCC)

The new capacity requirements were added to existing solar capacity in each BA, and from that we were able to calculate the new solar penetration level assuming that only solar was added to meet this new AI demand. We repeated this analysis for both solar PV and solar PV plus four-hour storage (exhibit 20). The MISO is the only BA that stays below the 5% threshold in the Solar PV, low-growth scenario, and both the MISO and PJM are at or below the 5% threshold in the low-growth scenario for solar PV plus storage. In all other cases, solar penetration levels exceed 5%.

Exhibit 20
Powering Artificial Intelligence
Solar Penetration Required to Meet AI Load by Balancing Authority



Source: FE Analytics and William Blair Equity Research

Next, we gathered the solar penetration levels required to meet new AI load forecast in five balancing authorities, for both low-growth and high-growth scenarios. The bar in exhibit 20 represents the 5% threshold where solar capacity begins to add costs to the whole system.

Lastly, using the regression analysis and the new data on solar penetration levels for expected growth in AI demand, we calculated the profile costs associated with adding AI to grid systems in these balancing authorities. Our results indicate the following:

- The total cost of AI to grid systems in 2030 in the 5 BAs analyzed will range from a minimum of $2 billion to a maximum of $27 billion if solar and solar plus battery systems are sought.

- The LCoE costs for solar standalone systems are $678 million and $3.7 billion in the low- and high-growth scenarios, but the profile costs are $1.3 billion and $23 billion, respectively, indicating that profile costs are between 2 and 6 times the LCoE costs.

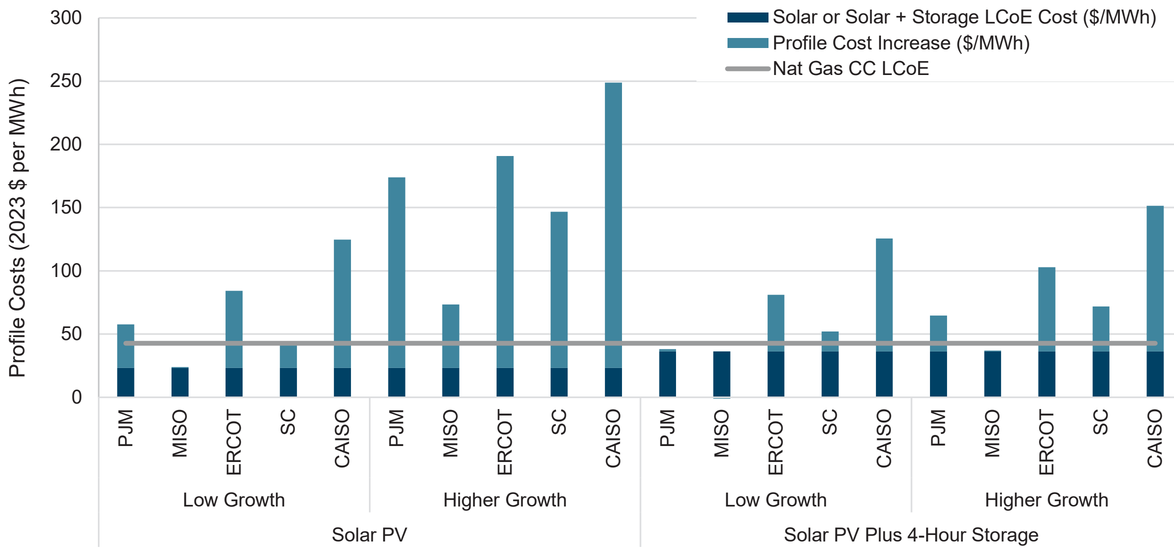
Exhibit 21
Powering Artificial Intelligence
Cumulative Costs by Technology

Technology	Growth Scenario	LCoE (mil $)	Profile Costs (mil $)	Whole System Cost (mil $)
Solar PV	Low Growth	678	1,352	2,030
	High Growth	3,669	23,751	27,420
Solar PV Plus 4-Hour Storage	Low Growth	1,058	731	1,789
	High Growth	5,731	7,275	13,006

Source: FE Analytics

Within the cumulative results, there is significant variation across each of the BAs. BAs that have solar penetration levels below the 5% level have the lowest costs in the solar plus storage technology; however, if capacity increases above the 5% threshold then gas tends to be favored. For example, the PJM and MISO are at or below the 5% capacity threshold in the low-growth, solar plus storage scenario. But if AI causes demand to grow at the high-growth scenario, then the cost of solar plus storage is either equal or greater than the cost of natural gas CC.

Exhibit 22
Powering Artificial Intelligence
LCoE vs. Profile Costs Required to Meet AI Load by Balancing Authority



Source: FE Analytics and William Blair Equity Research

One caveat to this analysis is that we do not have estimates of profile costs for natural gas additions. Adding capacity of any kind to a grid system will mean some sort of cost in terms of grid upgrades, but in general, the grid requirements for dispatchable power from natural gas are different than those from renewables. The question is whether the potential savings from renewables, which have a lower LCoE, is greater than the additional profile costs of managing variable renewable energy systems.

The Uncertain Role of Interregional Transmission

National Interest Electric Transmission Corridors

Interregional transmission is often touted as a panacea for most utilities and states—a way to make sure that renewable energy will be utilized without decreasing grid reliability. The Biden administration recently unveiled its National Interest Electric Transmission Corridors, with the goal of connecting renewable power in places where it is sunny or the wind is blowing and transmit the electricity to places that demand it—essentially, all of the lines connect different BAs. But a recent white paper from the Easter Interconnection Planning Collaborative called "Technical Considerations for Large Power Transfers Between Regions" reads like a shot across the bow to those who think that long haul, high voltage transmission is all that is needed to fix reliability issues. The white paper lists a number of key technical considerations, but the first one listed speaks loudly and clearly: "Enhanced interregional transfer capability should not become a substitute for each region ensuring it is meeting its resource adequacy needs, since reliability risks could increase. Specifically, regions will become more impacted by forced outages of major transmission facilities and other high impact events that can now cascade into adjoining regions."

Exhibit 23
Powering Artificial Intelligence
Transmission Corridors Proposed by DOE

Source: DOE

In other words, connecting different balancing authorities will not automatically make the overall system more reliable, rather it may do the opposite—make it possible for grid outages in one area to cascade into these newly connected areas. The result is that each BA will be required to meet resource adequacy in their own areas, which is the same way it has always been done.

Despite these concerns, renewable energy advocates still tout the benefits of interregional transmission. A recent report by the American Council on Renewable Energy (ACORE) identified energy and capacity arbitrage as the main benefits to expanded transmission between MISO and PJM. By connecting larger areas, the ability for abundant energy in one area to connect with demand in another increases and, in turn, more energy trading can occur. Similarly, generation capacity that is used to ensure demand can be met during peak times can also be sourced from more distant parts of the system, which can lower costs by reducing the overall new generation required to meet peak demand. Most importantly for renewable energy aficionados, greater transmission capability will ensure that renewable energy located afar can get to demand centers when the wind is blowing or when the sun is shining.

Not a Short-Term Solution

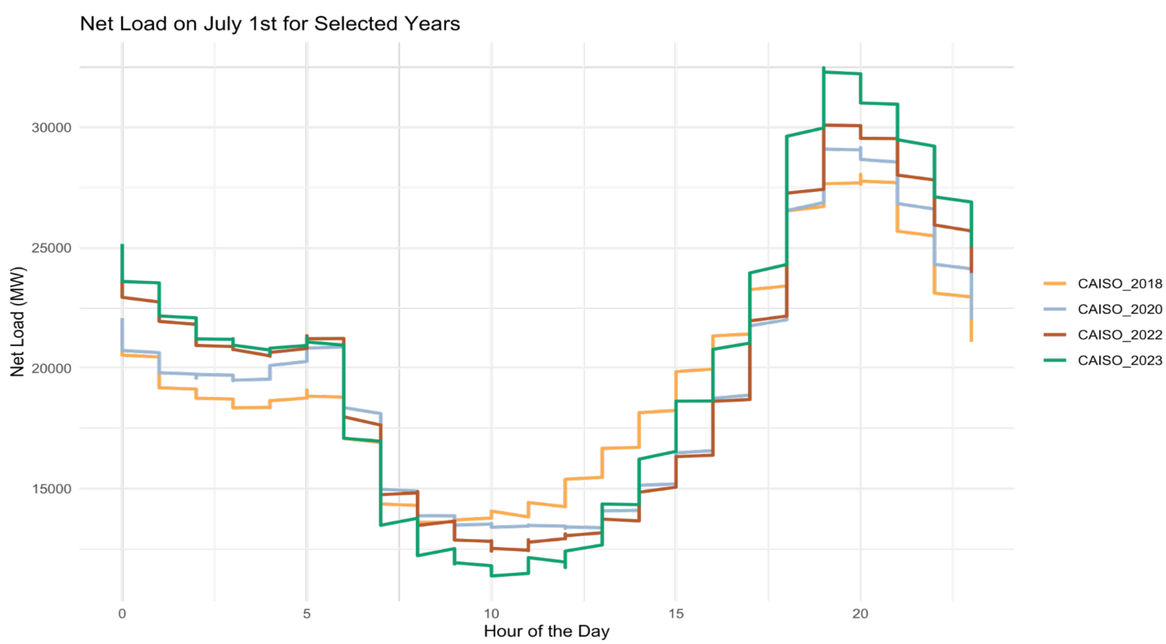
But there are several reasons why increasing interregional transmission will not be a solution for grid reliability in the short term, if at all. First, MISO, PJM, and all other BAs are used to doing their own long-term resource adequacy planning, and transitioning to a model where BAs coordinate with each other to find the most optimal and cheapest outcome will, at a minimum, take time. Second, even if the BAs are able to develop a workable model to collaborate, transmission planning and construction takes years. Third, there are conflicting views right now on how resource adequacy will be assessed at the interregional level. The ACORE report calls for generation sharing between BAs for resource adequacy purposes, while the Eastern Interconnection Planning Collaborative calls for each BA to assess resource adequacy independently.

The net result, we think, will be somewhat of an all-of-the-above strategy. Transmission will be sought as a long-term solution for renewable energy but will take years to execute, while in the short term gas will be used to balance the grid as renewable energy is built out with storage. It is also worth noting that gas with carbon mitigation solutions such as vertical indoor farming or even carbon capture and sequestration (CCS) may shift the view of environmentalists around natural gas.

A Case Study – California's Canary in the Solar Mine

California is facing serious grid challenges due to the adoption of solar, and it is serving as the canary in the "solar array" for the rest of the country. Most know the backstory, but just in case, here is a synopsis: the massive buildout of rooftop solar in California means that the CAISO has an overabundance of solar during the day, requiring conventional generators to shut down, and on sunny days with less demand, it even leads to the curtailment of solar power. But, as the sun sets in the evening and solar power to the grid plummets, the CAISO must ramp up generation, and quickly. This situation is often visualized in the now infamous "duck curve" (exhibit 24). The impact of solar production can be seen in the dip in net load throughout the day—often called the "belly" of the duck. The ramp-up of generation is represented by the steep climb in net load from 3 p.m. to 8 p.m. Data from the CAISO also shows how important natural gas (thermal) is to managing load in California (exhibit 25). Starting at midday, thermal generation is dispatched by the CAISO to meet demand (i.e., net load) throughout the afternoon and into the evening hours as power production from PV plummets.

Exhibit 24
Powering Artificial Intelligence
CAISO Duck Curve

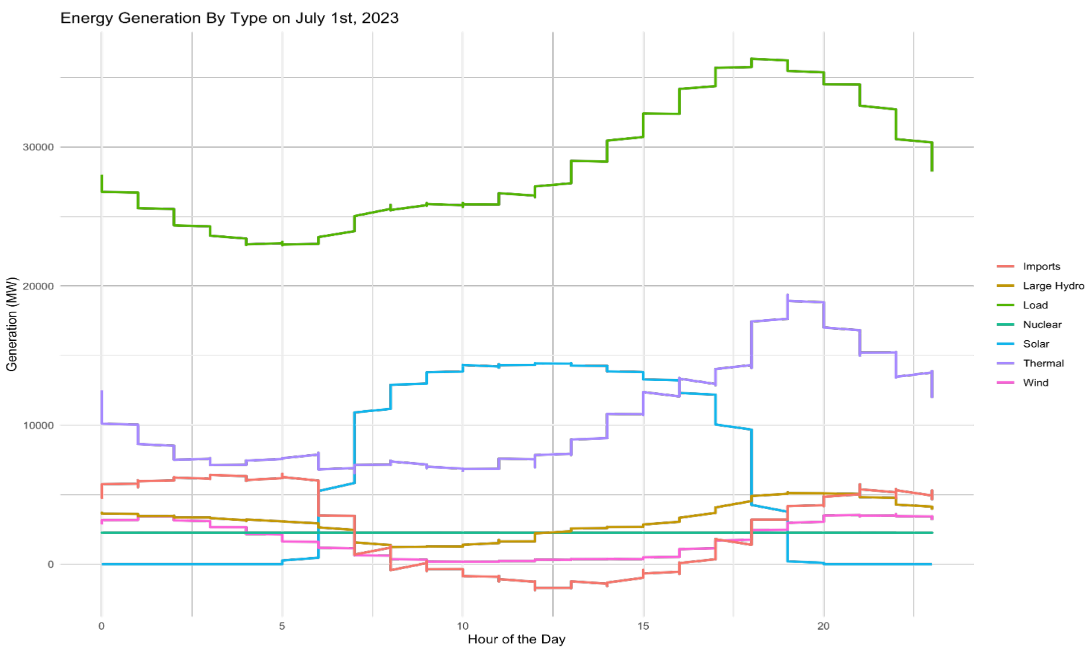


Source: CAISO

As more residential PV was built in California, the belly of the duck got deeper and deeper, requiring an even steeper ramp in the evening (exhibit 24). The issues represented in the duck curve led to the California Public Utility Commission (CPUC) drafting new solar net metering policies (called Net Metering 3.0), which vastly reduced incentives for residential PV, favoring instead PV + storage. While this pushes out the payback, in some cases by threefold, it also benefits the CPUC by pushing the costs back onto the constituents, in our opinion.

Natural gas is the unsung hero of California power production. As solar power diminishes in the late afternoon in California, something must replace it, and in the span of just a few hours, thermal generation in California, which is almost entirely natural gas, triples its output to meet the load profile (exhibit 25).

Exhibit 25
Powering Artificial Intelligence
CAISO Thermal Generation and Load

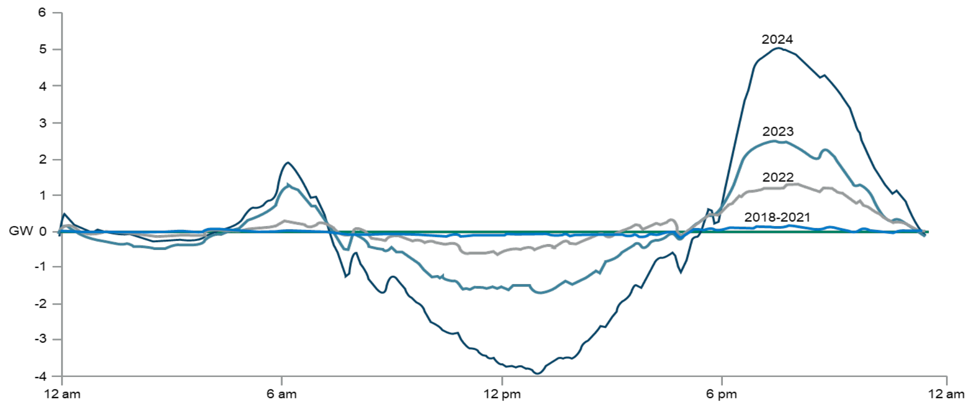


Source: CAISO

Battery Storage Offsets Solar ELCC

Batteries are also playing a larger role in balancing California's grid system. Battery dispatch to the grid in California has increased from almost negligible amounts in 2021 to 5 GW in 2024. Similar to gas, batteries can be used when needed to meet the evening peak in power demand, but unlike gas, batteries can also use excess solar production during the day to charge. The utility of batteries is evident in the fact they are a larger driver of CAISO's new Net Metering 3.0 policy changes, which incentivize PV plus battery storage over PV standalone systems.

Exhibit 26
Powering Artificial Intelligence
Battery Storage Increasing Contribution to CAISO

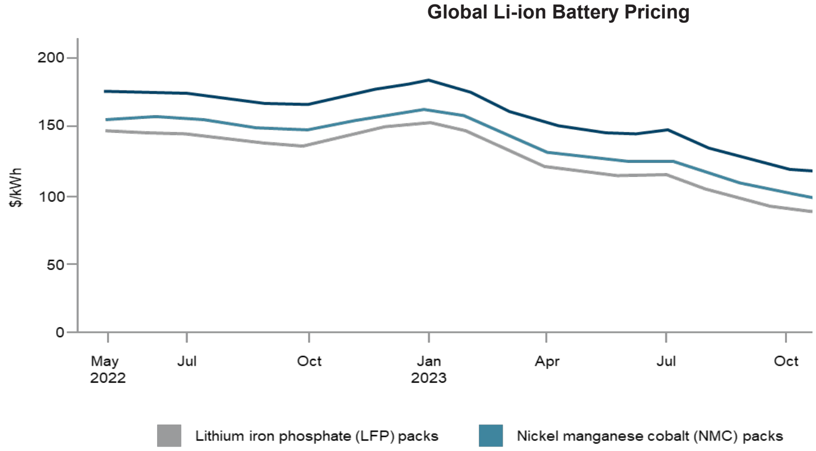


Source: CAISO and William Blair Equity Research

We expect CAISO's NEM 3.0 policy to become the norm in states with high solar adoption, namely Texas and Florida; outside the U.S., we see Germany adopting similar regulations.

In addition, battery prices have come down significantly thanks to an overbuild in China, especially for lithium iron phosphate (LFP) used in stationary storage. Since the peak in 2021, prices have come down from \$150/kWh to below \$80/kWh, and we have seen domestic China prices for prismatic LFP for stationary storage as low as \$50/kWh, which we believe is selling at zero or negative gross margin.

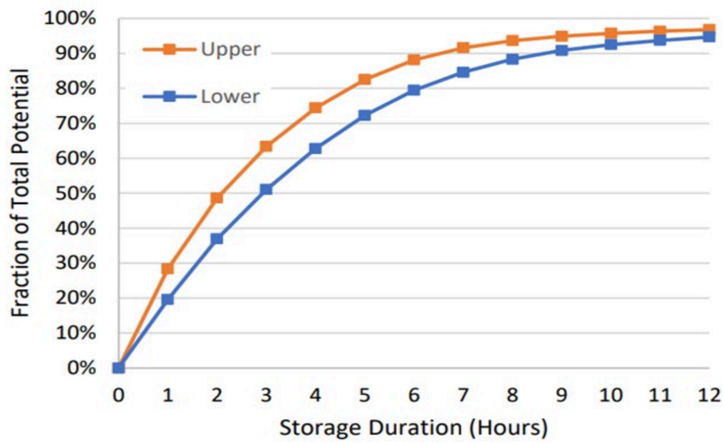
Exhibit 27
Powering Artificial Intelligence
Global Li-ion Battery Pricing



Source: William Blair Equity Research

Li-ion batteries are well suited for four-hour storage, ideal for daily time-shifting of solar generation from low energy demand in the afternoon to high demand in the evening, as seen in the duck curve in exhibit 24. According to NREL, over 60% of the value of energy time-shifting is captured with four-hour storage. Four-hour energy storage can replace a considerable amount of natural gas peaker plants that are used for immediate and short-term energy injections. However, data from ERCOT suggest much of the storage being deployed on the grid is not being used as four-hour storage but rather to help stabilize the grid.

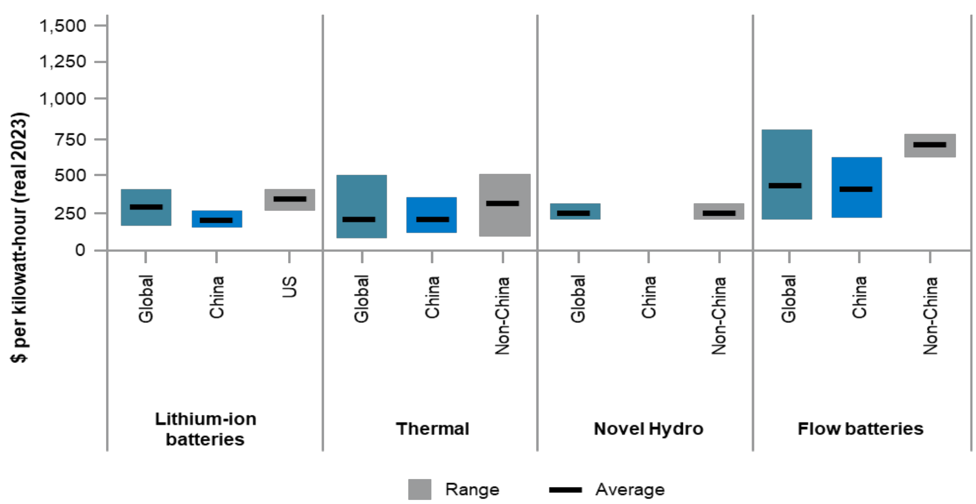
Exhibit 28
Powering Artificial Intelligence
Value of Energy Time-Shifting With Storage Duration



Source: National Renewable Energy Laboratory

There is also a significant market for long duration energy storage (LDES), which is characterized as eight hours or longer. Li-ion traditionally does not pencil out financially here, because of the linear relationship between cells and total energy—there are no scaling benefits as you add more batteries. Alternative systems and chemistries are being pursued that offer lower-cost LDES, like flow or iron-air batteries, compressed air, or gravity systems, although none have resulted in commercial adoption to date.

Exhibit 29
Powering Artificial Intelligence
Value of Energy Time-Shifting With Storage Duration



Source: William Blair Equity Research

Lower battery prices have made Li-ion more financially feasible for LDES. Recently, Li-ion was chosen for the first eight-hour energy storage system in Australia. The German company RWE contracted for the installation chose Tesla's Megapack for the battery system, adding 50 MW of storage to an existing 250 MW solar farm. This is one of the first examples we have seen of Li-ion, specifically LFP, entering the LDES application, and we expect adoption to increase as pricing comes down and alternatives continue to underdeliver.

The prices of the common stock of other public companies mentioned in this report follow:

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GE Vernova Inc. (Outperform)	$185.55
RWE Aktiengesellschaft	€32.12
The Southern Company	$85.74
Talen Energy Corporation	$151.86
Tesla, Inc. (Outperform)	$209.29

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NASDAQ: 17556.00

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