Voya Private Credit
Energy & Infrastructure Quarterly

Spring 2024: Power Generation's Wake-Up Call

VOYA INVESTMENT MANAGEMENT

Letter from the Voya PCIG energy & infrastructure team

Dear Investor,

In our Winter 2023 Edition of *Energy & Infrastructure Quarterly,* we mentioned that our 2024 publication would focus on renewable power assets. The decision to pivot to the larger topic of power generation proved prescient as power market operators across the U.S. released their 2024 long-term demand forecasts in which they signaled a step change in the country's future need for electricity. We hope that readers of this edition of *Energy & Infrastructure Quarterly* will come away with a better understanding of power markets more broadly, and the dynamics driving the renewed attention on America's power demand landscape.

As an organizational note, our esteemed colleague Fitz Wickham retired on May 31st. Fitz was integral in building Voya PCIG's Energy & Infrastructure Team into what it is today. His dedication and knowledge have left a timeless mark on our team.

Moreover, Chad Lewis joined the team in April. Chad has over 20 years of experience underwriting infrastructure and project finance transactions while working as a ratings analyst for S&P Global Ratings and Fitch Ratings. Chad was most recently a Director on the Infrastructure and Project Finance team at S&P. We're thrilled to welcome Chad to our team.

As always, we are happy to answer any questions you may have.

Sincerely,

The Voya PCIG Energy & Infrastructure Team

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Recent infrastructure transactions

Since the start of 2024, Voya PCIG has invested $653 million into ten energy and infrastructure transactions. The below table provides an overview of select investments.

Issuer	Overview
I-77 Mobility Partners	■ 26-mile express lane along a segment of I-77 located between Charlotte, NC and Mooresville, NC. ■ The company operates the project under a 45-year concession with the North Carolina DOT.
AES Clean Energy 3	■ Portfolio of renewable power projects across 10 states representing 2.8 GW of generation capacity. ■ Projects consist of solar, wind and battery storage. ■ Sponsors are the AES Corporation and Alberta Investment Management Company.
GIP Sharon Finco Pty Ltd	■ Under construction Australian LNG project with an anticipated in service date of 2026. ■ Once complete, the project will have an LNG liquefaction capacity of 5.3 mtpa. ■ The offtakers for the project represent large, experienced LNG buyers and include an Australian energy company and Japanese utilities and trading houses.
Diversified ABS VIII, LLC	■ Securitization of over 44,000 PDP wells in the Appalachian basin. ■ The wells are predominately conventional natural gas wells that have a compound annual decline rate of 4.7% per annum.
AP Grange Holdings LLC	■ A leading-edge semiconductor wafer manufacturing facility located in Leixlip, Ireland. ■ The facility will sell wafers to Intel under a long-term offtake agreement.

In addition to these investments, Voya PCIG reviewed an additional 38 investment opportunities, but declined to participate due to price, structure, business risk, or a confluence of the three.

One notable transaction that Voya PCIG declined to participate in was a foreign data center, due to insufficient lender protections in the event the data center's offtakers terminated their contracts.

Power generation's wake-up call

The Voya Private Credit Infrastructure team has been an active power generation investor for over 25 years. We've deployed client capital across a wide range of generation technologies, primary fuel types, locations, and regulatory environments. Growing demand for clean power, significant emissions reduction targets, and generous tax incentives have encouraged an enormous wave of renewable power development across the U.S., in which our clients are materially invested.

Power generation is a fascinating part of the energy industry. It resides at the intersection of multiple commodity markets, and both contributes to and depends on major macroeconomic variables—all while subject to continuous technological change.

The capital markets are looking to the building blocks that make AI possible—and this includes power.

Yet, apart from renewables, power has spent several years as something of a financial markets backwater. Slow-growth electric utilities seem boring alongside the Magnificent Seven, cryptocurrency ETFs, or whatever flavors-of-the-month the equity markets might otherwise offer.

Power demand growth in the U.S. has been flat for decades. ESG policies have made it challenging to attract investor capital for non-renewable thermal generation. Independent power producers owning fossil-fuel generation lost the equity market's interest to such an extent that some took themselves private. So even though we enjoy thinking, talking and writing about power markets, our affection for the topic has not exactly won us invitations to flashy cocktail parties.

But recently, the winds of public opinion have changed. The financial press has been jammed with news, commentaries and think-pieces on artificial intelligence development—and the significant power resources necessary to support its deployment. The capital markets are looking beyond AI's potential impact on corporate America to the "building blocks" that make AI possible in the first place: chip manufacturers, data centers—and, suddenly, power.

Tech industry missionaries are insistent that power capacity is a primary constraint on AI's growth and widespread application. Our inboxes are burgeoning with consultants highlighting parabolic power demand growth and investment bank conference calls on how to play the theme. It feels like this is power generation's wake-up call.

For this edition of our *Energy & Infrastructure Quarterly,* we will draw from our project financing insights to explain this renewed interest in power. After touching on recent market price signals, we cover some basics on how power is sourced and priced. We then move on to prevailing issues affecting supply and demand to explain the drivers of higher power prices and the concerns about supply adequacy.

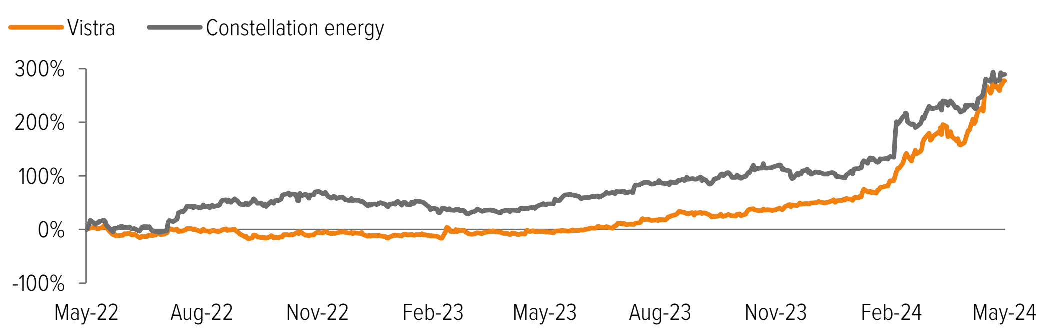
Follow the money

The financial markets are paying attention to power companies. The few public equities which can favorably leverage higher power demand and prices are among the market's best performers for 2024, after years of mediocre returns.

Independent power producers Constellation Energy Corporation (NASDAQ: CEG) and Vistra Corp (NYSE: VST) each hold large merchant generation portfolios. Their recent equity market performance exemplifies how the market has responded rapidly to a new narrative around power demand (Exhibit 1).

Constellation was spun out of utility holding company Exelon in 2022 and owns a roughly 22,000-megawatt (MW) nuclear fleet (the nation's largest), in addition to 11,000MW of renewable and thermal generation. It is the largest carbon-free power portfolio in the nation.

Exhibit 1: Power producers' share prices have nearly tripled in the past two years



As of 05/24/24. Source: S&P CapIQ.

Tighter supply/demand is driving higher profitability for owners of efficient generation capacity.

Vistra manages some 37,000MW of nuclear, gas, coal, solar, wind and storage resources across multiple fuel sources and domestic markets. Neither company operates as a rate-regulated utility, although both have large retail electricity businesses that sell power to household, business and industrial customers in markets that permit competitive energy sales.

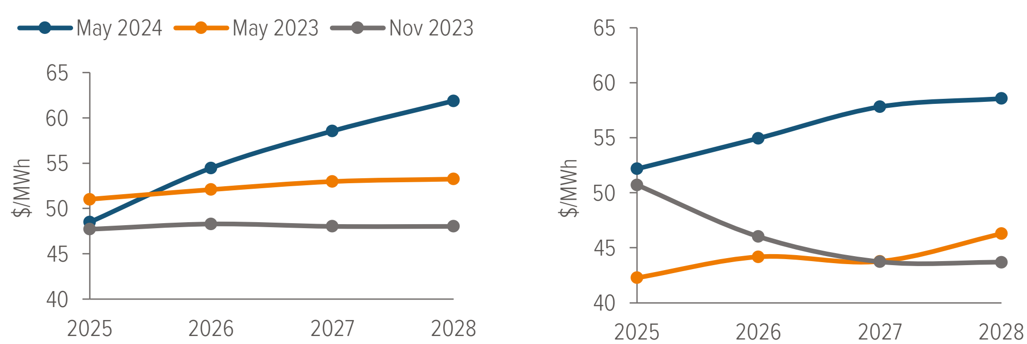
These two companies' outperformance is a response to clear signals of rising power prices from forward power markets. Exhibit 2 illustrates the change in forward power for 2025-28 in two large domestic markets: ERCOT (Texas) and PJM (widespread, but primarily the mid-Atlantic, where most data centers are located).[1] The greater slope of the forward power curve priced in May 2024 reflects a new expectation for rising power prices in both markets versus the more subdued forward pricing of May and November of last year.

Power prices are determined primarily by natural gas prices, and the two are closely correlated. Forward power and natural gas prices may be used to derive the implied future profitability of a natural gas-fired generator, or what the industry calls "spark spread" (Exhibit 3). The forward spark spread has shown an even greater growth than forward power prices over the last six months, with the positive slope of these curves projecting even more price increases. This rising spark spread suggests market participants see a significant tightening of supply and demand in these markets, and therefore sharply improved profitability for owners of efficient generation capacity.

Power prices are determined primarily by natural gas prices, and they are closely correlated.

Exhibit 2: Forward markets expect U.S. power prices to go up ...

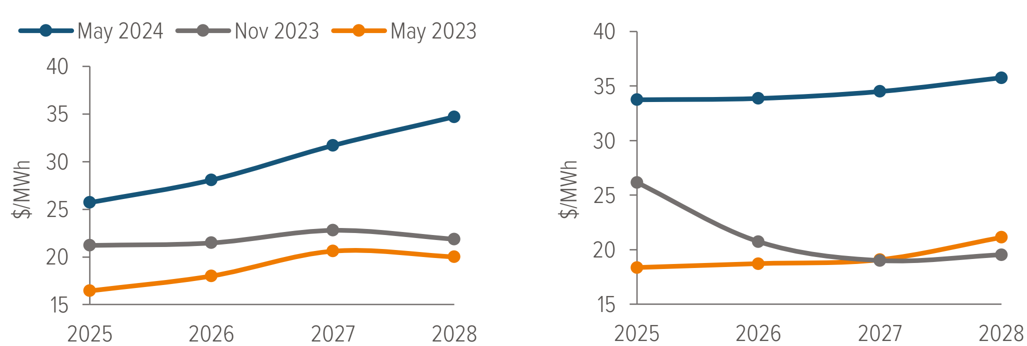
PJM forward power | ERCOT forward power



As of 06/01/24. Source: Bloomberg; prices are around-the-clock.

Exhibit 3: ... and power generation margins to increase

PJM spark spread | ERCOT spark spread



As of 06/01/24. Source: Bloomberg; spark spreads are around-the-clock and assume 7,000 mmbtu/MWh heat rate gas-fired generator.

[1] ERCOT stands for the Electricity Reliability Council of Texas and covers most of Texas except the Panhandle and some patches of East Texas; PJM stands for the Pennsylvania-New Jersey-Maryland Interconnection and includes those states as well as Ohio, Virginia, West Virginia, Delaware, large parts of Kentucky, and bits of North Carolina, Illinois (Chicagoland), Indiana, and Michigan.

Our diversity is our strength

The domestic U.S. power market is sourced from a diverse combination of fuels. This diversity is critical to uninterrupted power supply, as each individual resource provides benefits and limitations. Electric utilities and independent grid operators count on the favorable characteristics of each resource to deliver an optimal combination of reliable, lowest-cost and low-emissions power supply. Maintaining grid stability is a complex exercise, and operators rely on this full range of tools to—literally—keep the lights on.

Exhibit 4: Fueling the U.S.' power appetite takes a village

Resource	Source	Fuel cost	Capacity factor	Emissions	Capital cost	Dispatchable
Natural gas, baseload	Domestic drilling	Moderate	High	Moderate	Moderate	Yes
Natural gas, peaking	Domestic drilling	Moderate	Low	High	Moderate	Yes
Coal	Domestic mining	Moderate	Moderate/high	High	High	Yes
Nuclear	Global mining	Low	High	None	High	Yes
Wind turbine	Atmospheric	None	Low	None	Low/moderate	No
Solar photovoltaic	Atmospheric	None	Low	None	Low	No
Hydropower	Precipitation	None	Low/moderate	None	High	Yes, limited
Fuel oil, peaking	Domestic drilling	High	Low	High	Moderate	Yes

Source: Voya IM.

Maintaining grid stability is a complex exercise requiring a broad range of fuels to—literally—keep the lights on.

Before we dig into these sources, let's define some key terms.

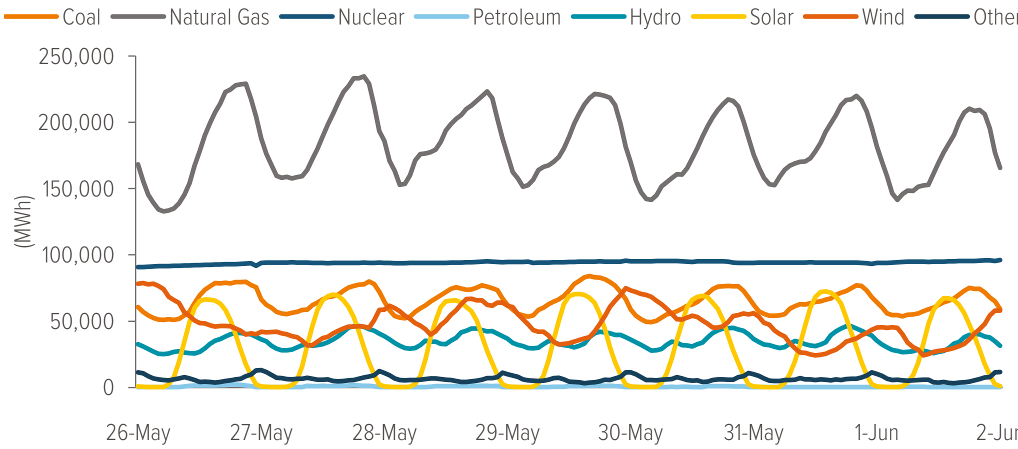
Baseload generation technology is designed to operate most or all of a 24-hour day. Baseload units are fuel-efficient but are slow to ramp to full capacity or vary their output.

Peaking generation can ramp from zero to maximum capacity in minutes, but it operates only during the few hours of daily peak demand. Peaking units are relatively fuel-inefficient, and their maintenance requirements can quickly elevate if they are run for longer periods than designed.

Capacity factor is the ratio of actual power generated to total potential generation assuming around-the-clock operations. Baseload resources will carry the highest capacity factors, while peaking power typically operates at a 10-20% factor. Renewable power generators operate at low capacity factors due to the intermittent nature of their wind and solar resources. Coal-fired projects are designed to operate as baseload, but some have seen their capacity factors fall in recent years due to displacement by cheaper gas-fired generation.

Generation volumes from each fuel type varies widely on an intraday basis. Exhibit 5 illustrates domestic generation over a week's time. The dominant share of total generation remains natural gas. Worth noting, too, is the predictable sunlight-following variability in solar generation (yellow line) versus the lesser predictability from wind (dark orange). Nuclear generation (dark blue line) operates continuously for up to 18-24 months and is the only non-variable resource.

Exhibit 5: A week of power generation shows wide variance among fuel types



As of 06/04/24. Source: Energy Information Agency.

Lastly, we highlight those resources which are **dispatchable.** This means that the grid operator can schedule when a resource does or does not generate power, and at a set volume and duration. Dispatchability is critical to planning, sourcing and delivering power over the course of hours or days. Power demand varies continuously, and grid operators must respond to small and large real-time changes with concurrent changes in generator output. Dispatchable resources enable operators to dynamically manage supply and other critical variables in the face of this variable demand.

Renewable resources are generally not dispatchable. The intermittency of their fuel—wind doesn't always blow; the sun goes down at night and can be hidden by clouds during the day—is such that operators cannot rely on renewables for certainty in volume, schedule or duration.

Renewable resources are cheap but intermittent, solvable with utility-scale battery storage.

Renewable intermittency can also be regionally correlated. Wind, hydro or solar resources tend to be strong or weak for all assets of that resource type operating within the same area. This correlation means that all regional generation from a given renewable resource will concurrently underperform, requiring considerable backup resources to address shortfalls.

Thermal resources tend not to show similar geographic correlation unless there is a regional disruption to fuel delivery, which is typically only associated with extreme weather. Still, renewables represent the cleanest and lowest-fuel-cost power available, so operators typically take renewable supply as it comes and use other resources to manage around this variability.

Utility-scale battery storage offers an attractive solution to renewables' intermittency. Batteries currently deployed alongside solar or wind projects can discharge for up to four hours at their peak capacity, which is sufficient to operate across most or all peak demand periods. Importantly, a charged battery is fully dispatchable. Batteries will typically charge during low-demand periods and discharge during peak demand hours.

Large-scale battery deployment is still in the early innings, but we expect storage will eventually displace some portion of peaking thermal resources now in service.

The building blocks of a healthy power system

Grid operators select generation resources for dispatch in ascending order of their variable operating costs. As fuel represents most of this cost, the cheapest fuel resource tends to be the lowest cost and the first to be called on by operators.

To meet expected demand, the operator will schedule the operation of each individual resource in order of sequentially higher operating cost until enough aggregate capacity is procured to meet demand. Generators "bid" their operating costs into the market on both a day-ahead and real-time basis.

Grid operators use day-ahead bids to schedule the operation of resources for each 24-hour day depending on projected power demand, plus a safety margin. Real-time bids are used to meet small changes in demand or address the unplanned outage of a scheduled resource.

Rapid price spikes during extreme weather are due to utilities needing unexpected amounts of peaking capacity.

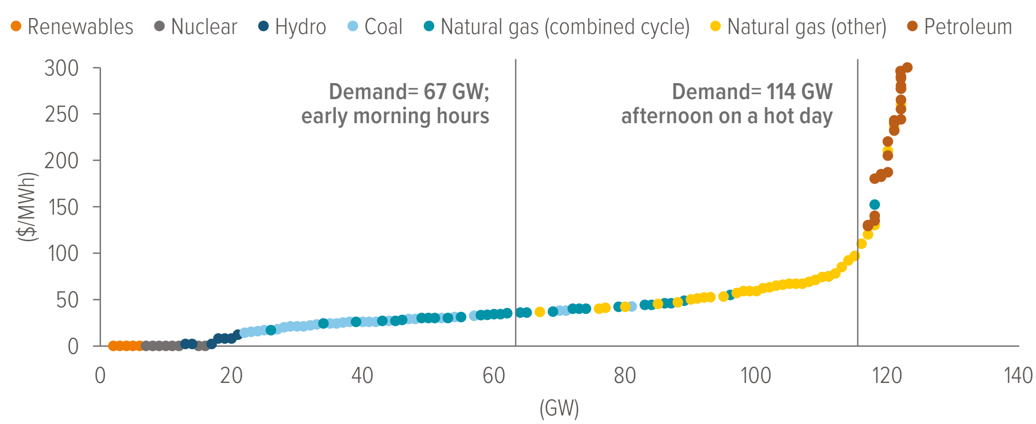
The "dispatch curve" in Exhibit 6 illustrates the order in which generators are scheduled to operate in a hypothetical power market. The x-axis represents the capacity available in this market, with each individual generation resource plotted on the supply curve in ascending order of its operating cost. The lowest-cost resources (renewables, hydropower, nuclear) appear on the leftmost portion of the curve, with successively more costly resources plotted as we move rightward.

Resources plotted in the middle of the curve tend to be a blend of coal- and gas-fired generators. The relatively inefficient gas- and petroleum-fired peaking projects appear on the rightmost part of the curve, with their operating cost increasing at an accelerating rate.

The steepness at this point along the curve implies that prices will increase rapidly should demand require the dispatch of these high-cost units. It is this dynamic which results in rapid price spikes seen during extreme weather or other conditions which drive power supply shortages.

The two vertical lines represent typical low and high demand. The point on the y-axis corresponding with the intersection of the supply curve and these vertical lines shows the market-clearing price for power in each of these two demand scenarios. In this hypothetical market, the low-demand price is less than $50/megawatt-hour (MWh) while the peak demand price is roughly $100/MWh. The generation resources to the left of the vertical line will operate, while those to the right will not.

Exhibit 6: The dispatch curve: a day in the life of a hypothetical power market



As of 08/17/12. Source: Energy Information Agency, Voya IM estimates.

Peaking capacity earns little to no profit, despite its high prices.

All operating resources will receive the market-clearing price, demonstrating the attractive profitability of operating renewable and efficient baseload assets in this hypothetical market. Notably, the resource setting the clearing price operates at breakeven; the peaking capacity provides the final megawatts critical to reliability yet earns little or no profit in doing so.

Natural gas resources dominate the portion of the supply curve between the low- and high-demand scenarios and will therefore most frequently set the clearing price for power. This is why gas and power prices are highly correlated. This correlation breaks down as successively less-efficient resources set the clearing price and the slope of the dispatch curve increases.

The large increase we previously noted in forward spark spreads illustrates how the more efficient / low-cost resources benefit handsomely as power demand rises. As demand rises the vertical line moves rightward, deriving higher prices as it climbs the steeper-sloped portion of the curve.

Yes, it's different this time

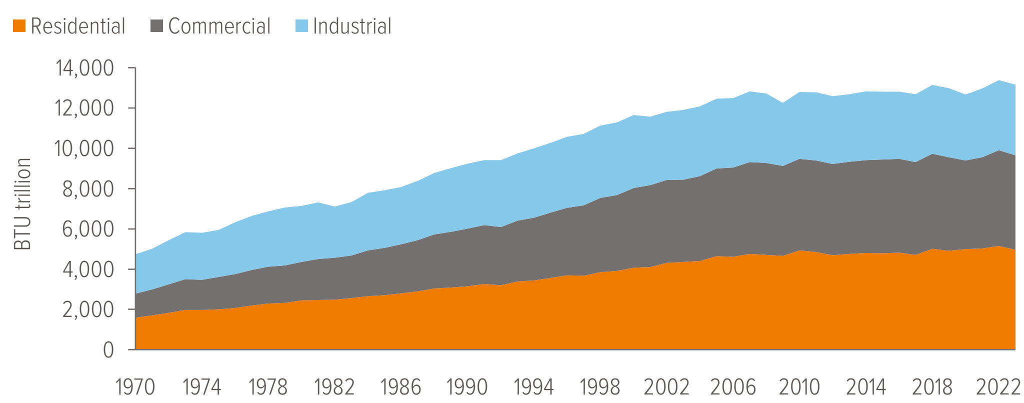
Domestic power demand growth was steady and strong from 1970 through the early 2000s, at which point the growth rate hit a wall (Exhibit 7). Economic conditions plus, energy efficiency in household and industrial consumption are partially responsible for this, as is conservation and growth in rooftop solar capacity.

So what is driving the renewed attention to power demand?

ERCOT and PJM attribute sharply higher long-term demand projections to a blend of population movements, expected data center construction, and new manufacturing & industrial capacity. PJM doubled its projected 2023-2030 demand CAGR to 1.8% (and higher still in data center hotspot Northern Virginia), while ERCOT expects an extraordinary 6% demand CAGR over the same period.[2]

Single-digit industry growth rates don't typically excite our readers; however, these growth rates have caught the industry flat-footed in terms of supply response to this new demand.

Exhibit 7: U.S. power demand has been broadly flat since the early 2000s ... but no longer



As of 05/31/24. Source: Energy Information Agency/.

Sudden increases in demand can only be met with short-term, high-cost fixes and concerns about grid reliability.

Utility-scale power supply takes time to develop and construct. Sudden increases in demand can only be met with short-term, high-cost fixes and elevated concerns about generation adequacy and reliability.

[2] PJM, "PJM Load Forecast Report January 2024" and "PJM Load Forecast Report January 2023"; ERCOT, Long Term Load Forecast, 01/18/24, and "CEO Board Update", 04/23/24.

U.S. data center power demand is already broadly equal to the entire retail electricity consumption of Virginia.

Driven by AI, data center demand is forecast to more than double in the next five years.

The capacity requirements necessary to meet this projected new load are remarkable. McKinsey forecasts that new data centers will require 35 gigawatts (GW) of new generation capacity, while ERCOT sees another 20GW necessary simply to support the electrification of Permian Basin oil and gas production. This is quite a lot—these two elements alone represent roughly 7.5% of current dispatchable domestic capacity.

There are numerous new and growing calls on existing power capacity: Domestic manufacturing, cryptocurrency mining, EV and hybrid vehicles, the "electrification of everything." However, data center expansion is central to the new supply/demand narrative across the industry and the capital markets.

Technology companies are investing aggressively in data center capacity supporting AI deployment as well as their other online services. BCG estimates that data centers consumed 126 terawatt-hours (TWh) of power in 2022, equivalent to 2.5% of total U.S. demand. This is already a lot—to put it into perspective, that's broadly equal to the entire 2022 retail electricity consumption of the state of Virginia 132TWh.[3]

BCG expects data center power demand to more than double by 2030, to 335-390TWh, or 7-7.5% of national demand. At least 1% of this (over 40TWh) is expected to come from AI-related demand.[4]

AI is particularly energy intensive. Power consumption of a single ChatGPT query is estimated to be more than 20x higher than that of a routine Google text search.[5] A large state-of-the-art data center can consume up to 300MW of generation capacity, equivalent to that of a utility-scale power project serving a moderately-sized city.

Development for these centers is under way across the country, with concentrations expected in the PJM, ERCOT, California and Georgia power markets.

You can't always get what you want

Renewable power development remains elevated in the face of this new demand. The Inflation Reduction Act added new tax credit incentives for clean power, including support for battery storage and some nuclear generation—as well as extensions for certain credits previously offered.

AI-focused technology companies maintain aggressive clean energy targets in powering their data centers. Data centers operate around the clock and target "seven nines" reliability (99.99999%; this works out to downtime of 3.16 seconds per year) from their power source, and this reliability doesn't come cheap. For example: Amazon recently agreed to co-locate a new center adjacent to an existing dual-unit nuclear project, striking a 10-year, 120MW+ power purchase agreement (PPA) with the power producer at well above market prices to ensure access to continuous zero-emission power.

Since not all new data center capacity can be built adjacent to a large nuclear plant, other means of meeting clean energy requirements will be necessary. Co-location of a data center with a wind or solar project is not feasible due to their intermittency.

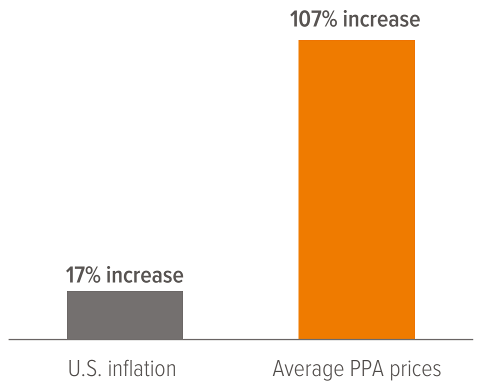
To meet their clean power commitments, technology companies are striking long-term PPAs supporting addition of new solar or wind capacity to the grids from which data centers will draw their power. Power prices paid under these PPAs continue to rise much faster than inflation, and we see this corporate demand growth continuing unabated for several years (Exhibit 8).

[3] Energy Information Agency, "U.S. Electricity Profile, 2022," 11/02/23.
[4] BCG, "The Impact of GenAI on Electricity: How GenAI is Fueling the Data Center Boom in the U.S.," 09/13/23.
[5] Wim Vanderbauwhede, "Emissions from ChatGPT are much higher than from conventional search," 11/17/2023.

Data centers' need for high reliability will likely result in premiums for guaranteed continuous power.

Exhibit 8: Wind and solar PPA prices have risen much faster than inflation

PPA prices vs PCE, 1Q20-1Q24 (%)



As of 06/01/24. Source: Level10, Federal Reserve, Voya IM estimates.

PPAs generate stable cash flow streams which support long-term financing for project development and construction. Their prices are driven by both construction cost and competition amongst buyers to procure clean power. High component and materials costs, interest rates and lingering supply chain issues are all drivers of the cost side of this dynamic.

Renewables projects average five years waiting in the interconnection queue.

Transmission access—interconnection to the grid—is the most significant constraint on renewable power development. The Lawrence Berkeley National Laboratory recently reported a robust development pipeline of some 12,000 projects representing 1,570GW and 1,030GW of renewable generation and storage capacity, respectively.[6]

Renewable capacity growth continues to outpace the buildout of new transmission.

These projects are subject to regulatory and utility reviews to determine both transmission improvements necessary for interconnection, and allocation of related costs. These costs can be high, and physical improvements subject to extended completion times. Projects sit in so-called "interconnection queues" pending these reviews.

The Berkeley Lab notes that only 14% of capacity seeking interconnection in the 2000-2018 period reached commercial operation by 2023. As of last year, wait time in the interconnection queue for the typical project reached five years. A recent Federal Energy Regulation Commission order is intended to speed projects through these queues, but execution remains dependent on grid operator and/or utility implementation.

New renewable capacity growth continues to outpace that of new transmission, with some projects facing significant curtailment, producing only what they can move through a constrained transmission network. Curtailments have proven especially problematic in moving power from western Texas wind and solar projects to meet demand in eastern population centers.

Where were you when we needed you?

While renewable power development pushes forward, interest in new gas-fired capacity remains uncertain. The Berkeley Lab reports 79GW of gas-fired capacity in interconnection queues at the end of 2023, representing less than 8% of the solar capacity in queues. This new proposed capacity is concentrated in the relatively gas-friendly southeastern US and Texas.

Interest in new gas capacity has been limited by recent EPA regulations that require new baseload gas generation projects to deploy emission capture and sequestration by 2032. Gas generators note that this system has yet to be commercially deployed, and that the cost renders any such projects uneconomic. The industry expects this new EPA policy to be aggressively litigated.

[6] Lawrence Berkeley National Laboratory, "Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection As of the End of 2023," April 2024.

Fossil fuels can't fill the gap as new gas capacity is constrained by stringent EPA regulations.

In the face of uncertain new supply, grid operators are overtly signaling concerns about the retirement of large thermal resources and the impact on grid reliability. PJM projects that roughly 40GW of its market capacity will retire by 2030, representing 21% of the market's 2023 fleet. The majority of these are coal retirements due to pending environmental policy, although their economic returns could improve via rising power prices. While an implementation delay in these policies would extend lifetimes, coal-fired plants have recently been minimally maintained in expectation of decommissioning, so higher power prices alone may be insufficient to economically justify such extensions.

Meanwhile, ageing thermal and coal resources are being retired, straining grid reliability.

The PJM interconnection queue is dominated by renewables. PJM notes that multiple megawatts of intermittent capacity will be necessary to replace a single megawatt of dispatchable thermal resource due to differing capacity factors and dispatchability.

Adding renewables but removing coal and gas capacity causes a push-pull on peaking capacity prices.

New gas-fired peaking capacity offers the best short-term solution to counter this increased intermittency. Over the medium term, batteries will be an important supply-firming resource. They are regularly paired with solar or wind projects, exposing them to interconnection queue delays. Peaking gas can be added more rapidly and with lower interconnection cost on brownfield sites in proximity to existing transmission.

Let's look at how PJM's expected developments would affect the typical dispatch curve.

- Brisk renewable development would add clean, inexpensive capacity at the leftmost points on the curve. Healthy demand and aggressive renewable power standards will assure that a portion of projects in development pipelines will survive interconnection review and reach commercial operation. These additions will tend to push the steep-slope portion of the curve further rightward.
- Base- and intermediate-load coal and aging gas capacity will remove dispatchable capacity between the minimum and peak demand. This will tend to draw the steep slope leftward.

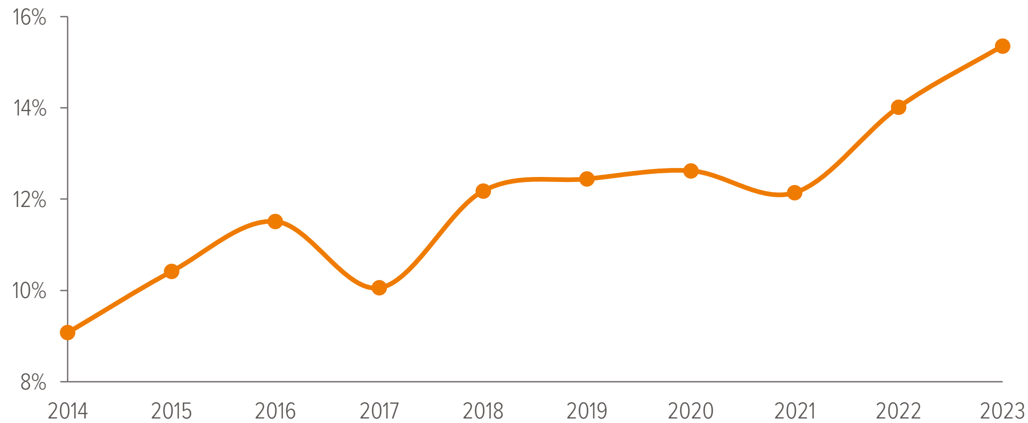
The net effect on aggregate capacity from these changes is to be determined, but we do know greater intermittency will result from greater renewable penetration. We are already seeing peaking capacity called on for this purpose.

Nationally, the capacity factor for quick-ramping gas has nearly doubled in the last ten years due to baseload retirements being replaced by new intermittent capacity (Exhibit 9). PJM is simply highlighting the risks to reliability as this dynamic proceeds.

PJM and other markets look to improve incentives for peaking capacity development. As we noted earlier, these resources are critical to reliability, but since they dispatch at or close to the clearing price for power, they earn low margins on their generation. In markets where generation is typically not carried in a utility rate base (PJM, ERCOT, others) these margins have proven too low to support adequate returns on capital.

Something's gotta give: Peaking capacity's lackluster economics has dampened development of significant capacity additions.

Exhibit 9: Gas peaking capacity factors have nearly doubled over the last decade



As of 05/31/24. Source: Energy Information Agency.

Grid operators in PJM, New England, California and elsewhere employ mechanisms to compensate peakers simply for maintaining available capacity; however, returns under these schemes have not always encouraged the development of significant new peaking capacity.

PJM has altered capacity market rules with the clear purpose of driving higher capacity prices. ERCOT does not offer a capacity payment, but the state government is offering subsidized financing to support construction of new gas resources and other mechanisms to encourage development of new gas-fired capacity.

Where do we go from here?

Despite numerous uncertainties, the following four issues are likely to shape the short- and medium-term generation landscape:

- **Power prices will rise.** Alongside the changes we've described in generation resource, we see increasing calls on domestic gas supply. Despite plentiful reserves, conditions are favorable for rising natural gas prices, due to incremental demand for domestic power, as a manufacturing feedstock and for LNG export. This inflation will be realized across all electricity consumers.
- **Regional demand concentrations will give rise to reliability concerns in some markets.** The combination of population migration, industrial growth, and data center expansion will drive a push for additional generation resources to maintain grid reliability.
- **Progress on energy transition will slow** as reliability and intermittency concerns will be addressed via new natural gas generation capacity. The political responses to this development should prove interesting.
- **The potential reconsideration of new nuclear capacity is a wild card.** Well-funded research and development on small modular reactors remains under way. Successful domestic commercialization at scale could offset many of the issues we have outlined, although timelines for any significant development will be long.

Implications for electric utility and power project financings

As with any meaningful change in industrial status quo, there are a few things creditors and investors in this sector should consider regarding their current holdings and future allocations.

1. **Existing generation assets of all kinds will benefit.** Power prices will continue to move in line with natural gas, but we do believe that power supply stack is tightening and that efficient assets will see higher margins. Projects currently under fixed-price PPAs will not see immediate benefit although prospects are improved for either their recontracting negotiations or their move to merchant operation.
2. **The outlook for existing natural gas projects will improve greatly.** These projects were until recently thought to have limited lifetimes. Peaking generation development will depend on improved compensation for providing available capacity. Market mechanisms for pricing this capacity need further improvement, but we see consensus on this point as well as recent bilateral capacity contracts signaling improved value for peaking capacity.
3. **We do not yet see a groundswell of interest in developing new gas power projects.** We suspect that investors will need evidence of sustained improvement in future returns before committing their capital. Capacity mechanisms have proven fickle in supporting peaking projects, and capital costs are high for all natural gas generation. Concerns linger about the long-term competitiveness of natural gas. New gas generation projects carry 30+ year economic lifetimes. Improved battery storage technology and/or a nuclear renaissance deploying smaller modular reactors could all push gas further to the dispatch curve's margins.
4. **The pipeline for renewable project financings should remain robust.** Well-capitalized sponsors will be at an advantage due to being able to bear the cost of capital, equipment, and labor through extended development timelines.
5. **There is potential for greater frequency and size of transmission project financings outside of the traditional utility framework.** Investors should also consider their appetite for financing natural gas-fired capacity, for both existing projects and new developments.
6. **Utility regulators in high-demand markets will face greater challenges.** Large load demands from data centers and/or industrial users will require new generation and transmission capacity. While these new customers offer attractive regional economic development, cost allocation for these projects will prove difficult as rate payers may see no direct benefit offsetting their higher electric bills.
7. **Difficult rate cases and greater uncertainty around allowed equity returns and credit quality are likely in the face of elevated capital expenditure in a "higher-for-longer" rate environment.**

Over the last 20 years our infrastructure team has successfully invested through volatile power markets and an ongoing energy transition. We will utilize these experiences to selectively establish new investments in power assets that are well-positioned to navigate the sector's changing dynamics.

In our next edition of *Energy & Infrastructure Quarterly,* we will further explore renewable power projects.

A note about risk

The principal risks are generally those attributable to bond investing. Holdings are subject to market, issuer, credit, prepayment, extension and other risks, and their values may fluctuate. Market risk is the risk that securities may decline in value due to factors affecting the securities markets or particular industries. Issuer risk is the risk that the value of a security may decline for reasons specific to the issuer, such as changes in its financial condition.

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