

The Misguided Stampede to Build Gas Power Plants

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Contents

Key Findings.....	3
Executive Summary	4
The Cost of Higher Gas Prices	5
The Costly Problem of Price Spikes	6
Creeping Price Increases	7
Rising Costs Undercut Gas' Competitiveness.....	9
Capital Costs	9
Fuel Costs.....	10
Pipeline Costs	10
Competition Is Intensifying.....	12
Gas Investments Stranded Cost Risk	12
The Rise of Battery Storage.....	13
Renewables—Available Now, Faster to Build, Easier to Scale	17
Conclusion.....	19
About IEEFA.....	21
About the Author	21

Figures and Tables

Figure 1: Average Monthly Natural Gas Price in 2025 Dollars (\$/million Btus	5
Figure 2: Dominion's Greenville Plant Shows Big Impact of Small Gas Price Increases	7
Figure 3: U.S. Battery Storage Installations Hit 50GW and Are Growing Quickly.....	14
Figure 4: Battery Storage Is Significantly Reducing California Gas Generation.....	15
Figure 5: Weather, Geopolitical Spikes in Gas Prices Are Costly for Consumers.....	17
Figure 6: Renewables and Battery Storage To Make Up Most Capacity Additions to 2035	19
Table 1: Expected ERCOT Capacity Additions to 2028 (MW)	18

Key Findings

Consumers face significant risks from spikes in natural gas prices caused by weather and geopolitical events; these risks rise in relation to the amount of new gas-fired capacity added to the grid.

Rising LNG exports will lead to additional price volatility in the U.S. and also could lead to persistent and long-term increases in natural gas costs, a double whammy for consumers.

The price of new combined-cycle gas plants is roughly triple the cost of projects built in the early 2020s and orders placed now likely will not be fulfilled until 2030, or later.

The costs of wind and solar, paired with dispatchable battery storage, are not tracking the rapid climb of gas prices; hardware is readily available; and they have no fuel costs.



Executive Summary

The stampede to build new gas-fired power generation is real; one recent U.S. estimate showed that 133,000 megawatts (MW) of new capacity is on the drawing board.¹ But those planned projects overlook several major financial risks, both for utility customers and investors.

A growing issue for gas projects, and one largely overlooked in the planning process, is the impact of the fuel's cost on the ultimate price paid by consumers for power. Utilities generally pass fuel costs directly through to consumers, which effectively eliminates the companies' financial risk from gas price spikes. Customers are not as lucky, as was evident clearly in 2022 when Russia's invasion of Ukraine sent gas prices soaring, pushing electricity costs from gas-fired power plants up sharply. In addition, weather-driven price spikes can result in significant unexpected costs being pushed onto U.S. consumers, as happened just this past winter. Similar weather and geopolitical spikes cannot be ruled out in the years ahead. Finally, the growth of U.S. liquefied natural gas (LNG) exports could result in more persistent and long-term increases in gas costs, and further boost price volatility. As a consequence, fuel costs for gas-fired electricity could become significantly higher compared with past years, when fracking production was surging and exports were minimal.

In addition, the cost for new gas-fired generation has jumped over the last couple years. The price of the newest combined-cycle plant proposals is now at least \$2,500 per kilowatt (kW) installed, or \$2.5 billion for a 1,000-megawatt (MW) unit. This is roughly triple the cost of projects built in the early 2020s and generally does not include financing costs for the plant or costs associated with building or expanding a gas pipeline to supply the generator. Those costs will inevitably be passed on to consumers, either through local utilities' regulated rates or higher power prices in competitive markets.

Finally, most of these new projects will not be ready for years, and the major turbine manufacturers have essentially sold out their combined-cycle capacity through 2030. Those lengthy construction time frames could lead to additional consumer costs due to continued supply chain tightness and competition for scarce, trained labor. And if the new projects are not connected on schedule, local utilities could be forced to buy electricity on the wholesale market. That replacement power would likely be expensive, given expected demand growth and a tightening generation market, which would push additional costs onto utility consumers.

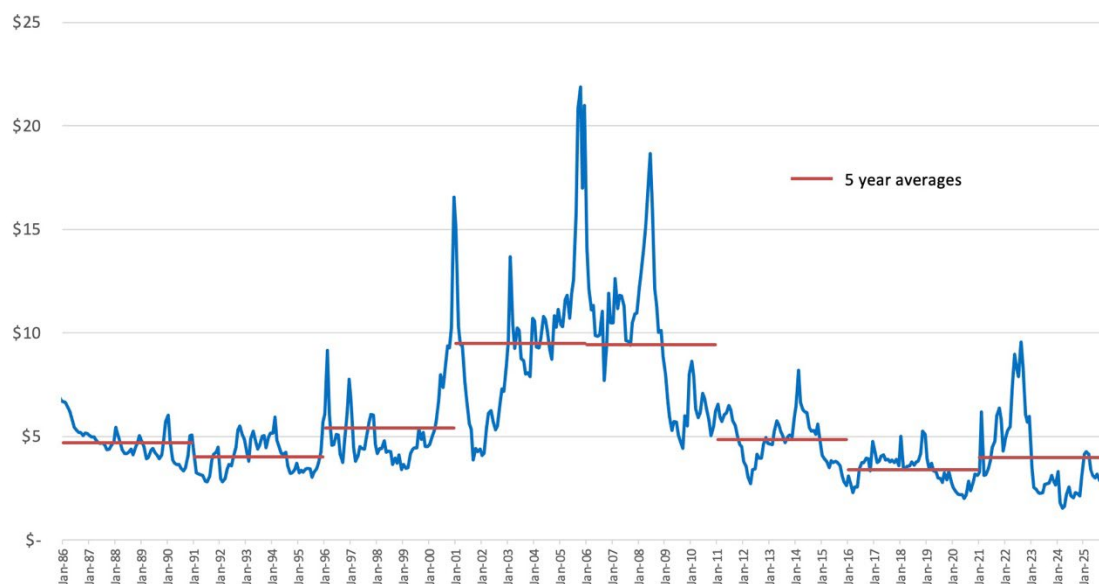
Wind and solar do not share the shortcomings of gas. Their costs are not tracking its rapid upward climb; the hardware also is readily available, so projects can be built in 18 to 36 months; and they have no fuel costs—ever. Paired with dispatchable battery storage, which continues to benefit from declining capital costs, renewables offer firm power and fixed costs on short development timelines.

¹ S&P Capitol IQ. U.S. Power Sector Planning 133 GW of New Natural Gas-Fueled Capacity. January 20, 2026. (Proprietary).

The Cost of Higher Gas Prices

While gas prices have been relatively low for the past 15 years, there is no guarantee they will remain so in the future. The graphic below shows clearly that long stretches of high prices are possible. For almost a decade in the early 2000s, gas prices held near \$10 per million British thermal units (MMBtu) and sometimes spiked to \$15-\$20/MMBtu, five to 10 times higher than recent levels. Admittedly, those higher prices occurred before the fracking era, which has unlocked new gas supplies in the U.S. But those higher prices also occurred well before gas became the leading generation resource on the U.S. grid, now providing more than 40% of annual demand. In addition, that was before the U.S. became the world's largest exporter of LNG, which has exposed domestic consumers to rising price volatility due to international events.

Figure 1: Average Monthly Natural Gas Price in 2025 Dollars (\$/million Btus)



Source: EIA and FRED, IEEFA calculations.

As a result, the U.S. may be at the beginning of a new, higher-price period, driven upward by LNG exports and increased gas consumption for domestic electricity generation. Average Henry Hub prices were significantly higher in 2025 than the year before, and the Energy Information Administration's (EIA) February short-term outlook projects that prices will continue to rise in the next two years, averaging \$4.30/MMBtu in 2026 and \$4.40/MMBtu in 2027.² EIA has previously cited rising LNG exports and continued growth in domestic consumption as the key drivers of its projection of higher gas prices.³

² EIA. [Short-Term Energy Outlook](#). February 2026.

³ EIA. [Short-Term Energy Outlook](#). January 2026, p. 3.

Looking further out, Wood Mackenzie sees the same issues—LNG exports and higher domestic power sector use—leading to significantly higher average gas prices from 2030-35. Specifically, the consultancy projects that Henry Hub prices will average \$4.90/MMBtu during this period.⁴

“In effect, the success of U.S. LNG supply growth will come at a cost to U.S. consumers and to the benefit of those in Europe,” it said.⁵

The Costly Problem of Price Spikes

Higher gas prices result in significantly higher consumer costs. This is best seen by examining the impact of rising prices on annual fuel costs at individual plants. To show this, IEEFA looked at Dominion Energy’s most efficient combined-cycle gas plant in Virginia: the 1,588 MW Greenville facility that came online in 2018.

The efficiency of a turbine is commonly measured via its heat rate, which shows the number of British thermal units (Btu) required to produce a kilowatt-hour (kWh) of electricity (expressed as Btu/kWh). The lower the number, the more efficient the turbine. The heat rate at Greenville has averaged about 6,500 Btu/kWh in its first seven years of full commercial operation, putting it among the most efficient plants in the country.⁶

Notwithstanding its efficiency, gas prices matter a lot. In 2021, the Greenville plant generated 11.5 million MWh of electricity, spending \$307.9 million on gas to operate the facility. The next year, as gas prices increased due to Russia’s invasion of Ukraine, Greenville produced slightly less electricity, 11.1 million MWh, but its fuel costs soared, climbing more than \$200 million to \$518.7 million for the year.

That increase was felt throughout Dominion’s Virginia service territory. State regulators in November 2023 approved a utility plan to securitize its unrecovered fuel costs from 2022 and recover them over time to reduce the impact on consumers; those costs are generally recovered within a year.⁷ In January 2024, Virginia Electric Power Co., Dominion’s operating subsidiary in the state, issued \$1.28 billion in securitized debt to recover these deferred fuel costs over seven years, with the last payment not due until May 2031.^{8 9}

The upshot of that event is that Dominion Virginia customers will still be paying for 2022’s gas price spike, even as they are forced to pay for the newest price shock, courtesy of the January 2026 winter storm that sent gas prices soaring in Virginia and across the PJM market. Monitoring Analytics, the PJM market monitor, reported that total wholesale power costs for the month more than doubled,

⁴ Wood Mackenzie. [The LNG Lifeline: Will Cheaper Global Gas Resuscitate European Industry?](#) January 2026.

⁵ [Ibid.](#)

⁶ EIA [data](#) shows that the average heat rate for combined-cycle plants built between 2010-22 is 6,960 Btu/kWh.

⁷ Virginia State Corporation Commission. November. [Dominion Energy Virginia Customers to Receive Rate Relief from First-of-its-Kind Financing in Virginia](#). 3, 2023.

⁸ Fitch Ratings. [Fitch Affirms IDRs of Dominion Energy and Subsidiaries](#). April 5, 2024.

⁹ Virginia Power Fuel Securitization, LLC. [Pricing Term Sheet](#). February 5, 2024.

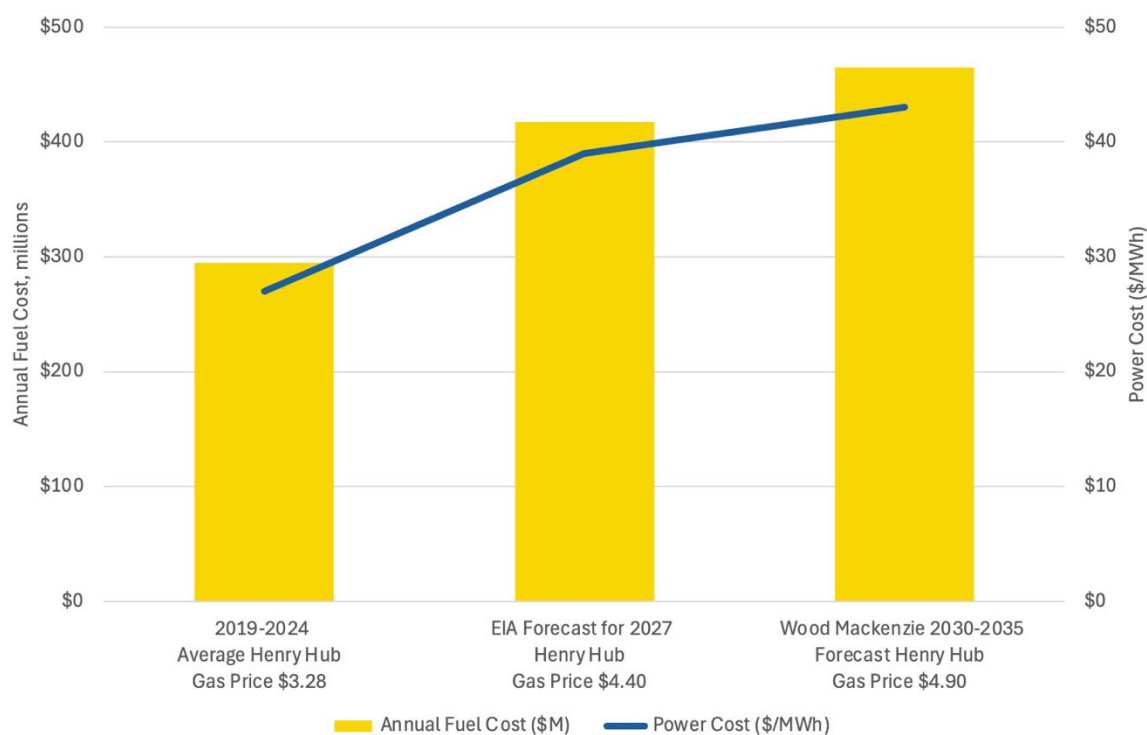
jumping from \$7.3 billion in 2025 to \$15.4 billion in 2026, driven largely by a sharp rise in gas prices. For the month, the Henry Hub spot price averaged \$7.72/MMBtu—close to the highs posted in 2022, which led to the massive consumer fuel cost increase that year.

Creeping Price Increases

Price spikes are not the only risk for consumers from the ongoing gas stampede. General price increases, along the lines projected by EIA for the next couple of years and Wood Mackenzie for the early 2030s, also pose significant cost risks for utility consumers.

Here again, it is easiest to show this by returning to Dominion’s Greenville plant. The graphic below illustrates the high additional costs that consumers would have to shoulder, even for relatively small cost increases in fuel costs.

Figure 2: Dominion’s Greenville Plant Shows Big Impact of Small Gas Price Increases



Source: S&P and EIA data, IEEFA analysis

The projected increases in both annual fuel costs and the cost per megawatt-hour (MWh) are driven by higher gas prices. From 2019-24 (covering the plant’s first full year of operation through the most currently available plant data), Henry Hub prices averaged \$3.28/MMBtu. EIA expects 2027 Henry Hub prices to climb to \$4.40/MMBtu, an increase that would lead to significantly higher costs for

Dominion consumers.¹⁰ IEEFA estimates that total annual fuel costs at this one plant could jump 41% from its five-year operating average, climbing to more than \$417 million from \$295 million. Assuming the plant generates the same amount of electricity (it averaged 10.8 million MWh from 2019-24) that would push the cost of its power up sharply, from \$27.10/MWh to \$38.50/MWh. Those numbers would climb even higher from 2030-35 under Wood Mackenzie's outlook for Henry Hub prices of \$4.90/MMBtu.

Renewables offer far better energy price security, given they have no fuel costs. Interestingly, this point was made by Dominion in its ongoing legal fight with the Trump administration to complete construction of its 2,600 MW Coastal Virginia Offshore Wind project. In a Dec. 23, 2025, filing seeking to lift a stop-work order issued by the Interior Department, Dominion pointed out that the wind project would save its customers \$300 million annually in fuel costs during its first 10 years of operation.¹¹ The company estimates that the project will generate 9.5 million MWh of power annually, which implies Dominion's power costs will be roughly \$31.60/MWh. However, if the utility's generation costs are higher, as EIA and Wood Mackenzie estimate, then the savings to consumers from this fuel-free resource will be much higher as well. At the \$38.50/MWh cost noted previously for 2027, the consumer savings from this offshore wind project would exceed \$365 million in just one year.

Florida Power & Light also touts the consumer savings that fuel cost-free resources provide—in this case, solar. FPL, a unit of NextEra Energy, one of the world's largest renewable and battery storage developers, reported in 2025 that its consumers saved more than \$1.1 billion in fuel costs from 2017-24 due to the utility's solar buildout.¹² More than a third of those savings were realized in 2022 during the Russian-induced gas price spikes. That year, the utility's solar generation totaled 7.6 million MWh and saved customers \$375 million. In other words, each megawatt-hour of solar generation saved \$49.14.

FPL serves as a good example for the benefits of fuel-free resources, particularly solar, since the utility's generation resources are highly concentrated. As of June 2025, its generation mix was 70% gas, 18.8% nuclear, and 8.4% solar, with the remaining 3% coming from oil, coal, and purchased power.¹³ The company's nuclear capacity runs consistently, meaning any changes in its generation mix are between gas and solar, as borne out by its current long-term resource plan, which runs through 2034.

The company projects that its solar generation will jump from 12.4 million MWh in 2024 to 55.8 million MWh in 2034, accounting for all the company's growth and significantly reducing gas' share of its generation. Specifically, FPL says gas' share of its generation mix will drop from 71.4% to 45.7% while solar climbs from 8.4% to 34.7%. That switch will cut the utility's gas consumption from

¹⁰ EIA. [Short-Term Energy Outlook](#). February 2026.

¹¹ U.S. District Court, Eastern District of Virginia. [Case 2:25-cv-00830-JKW-LRL](#). December 23, 2025.

¹² Florida Power and Light. [Ten-Year Power Plant Site Plan 2025-2034](#), p. 13.

¹³ [FPL Energy News](#). April-June 2025, p. 2.

742 billion cubic feet (bcf) in 2024 to an estimated 523 bcf in 2034—saving consumers billions of dollars.

Using Wood Mackenzie’s Henry Hub price estimate of \$4.90/MMBtu for 2030-35, this would translate into annual savings of more than \$1.1 billion. Factoring in a premium above the Henry Hub price to account for pipeline transportation, the total savings could exceed \$1.5 billion. The exact total would change each year depending on gas prices, but the savings from foregone fuel costs would continue to accumulate, providing a major incentive to build out additional solar resources.

Rising Costs Undercut Gas’ Competitiveness

The economic competitiveness of gas-fired generation has rested on three pillars: the relatively low and stable capital costs for new turbines, the low cost of fuel to run them, and the low cost of building the pipelines needed to deliver that fuel to power plants. All these assumptions appear to be crumbling

Capital Costs

In Lazard’s annual report tracking the levelized cost of energy (LCOE) across different generation technologies, the upper bound of the capital cost for combined-cycle gas turbines (CCGT) ranged from \$1,300 to \$1,600 per kilowatt (kW) of installed capacity from 2015-25.¹⁴ At the lower bound, installation costs remained at or below \$1,000/kW through 2024. This translated into low projected power prices from gas-fired power plants, with Lazard expecting them to range from \$45 to \$75/MWh.

Those power prices are no longer valid. In its 2025 report,¹⁵ Lazard added a footnote noting the impact of the recent run-up in capital costs, which have effectively doubled to an estimated \$2,500/kW over the past two years. Using a range of \$2,400- \$2,600/kW, Lazard estimated that power prices from new combined-cycle gas plants would be \$107/MWh. That price could be driven up even further if other expected performance standards aren’t met -- for example, if a plant’s heat rate rises and the facility needs to consume more fuel to produce the same amount of power. But the broader takeaway is simple: At these elevated capital levels, combined-cycle gas plants are no longer a low-cost electricity source.

By comparison, the same Lazard analysis projects unsubsidized costs for new solar and onshore wind will range from \$29-\$42/MWh for solar and \$26-\$54/MWh for wind—less than half the projected cost for gas. The rapid evolution of the battery storage sector is discussed in greater depth below, but it is noteworthy that Lazard also projects that much of this solar and wind capacity can be firmed

¹⁴ Lazard has produced an annual report on the levelized costs of different energy production options for 18 years. It serves as a useful benchmark of developments over time.

¹⁵ Lazard. [2025 Levelized Cost of Energy](#). June 2025.

with dispatchable battery storage and still cost less than its estimates for power from new combined-cycle gas plants.

Fuel Costs

The estimates regarding combined-cycle power costs also rely on low fuel costs. Lazard's projections consistently assume fuel costs will be \$3.45/MMBtu, but Henry Hub prices for the last five years have averaged \$3.72/MMBtu, and EIA expects them to rise to \$4.40/MMBtu in 2027. That would lead to higher prices from gas-fired power plants, and it could be just the beginning of additional upward movement driven by rising LNG exports and higher domestic demand. Wood Mackenzie, for example, recently estimated that Henry Hub prices will average \$4.90/MMBtu from 2030-35.¹⁶

Looking specifically at Dominion's Greensville combined-cycle plant that we discussed in the prior section, a gas price of \$4.40/MMBtu would push total annual fuel costs at the plant up by an estimated \$122 million compared to its long-term average, assuming generation at the plant remains relatively stable compared to past years. Utility ratepayers would be forced to pay for that increase. While substantial, that example simply represents expectations of general price increases; gas price spikes are another issue entirely. Annual fuel costs at Greensville jumped to \$518 million in 2022, up 68% from the prior year, following the Russian invasion of Ukraine. All those costs were also passed through to utility ratepayers

In contrast, the power costs from wind and solar are known from the first day of operation. Given that renewable power costs are already lower than gas-fired generators, and the price of gas is projected to climb, the gap between the two types of generation resources is only going to widen.

Pipeline Costs

A third factor to consider when discussing new gas generation is the capital cost of new pipelines. As with gas turbines, pipeline costs have risen significantly in the past couple of years.

A 2025 analysis of data from the Federal Energy Regulatory Commission (FERC) and the EIA by BTU Analytics showed that pipeline construction costs (calculated as the price per mile) had jumped by 90% for projects completed before 2024 compared to those completed or proposed since 2024.¹⁷ Importantly, that calculation does not include the blowout costs of the Mountain Valley Pipeline, which entered commercial service in 2024, years late and with a total cost of roughly \$9.7 billion — \$6.2 billion more than the original estimate.¹⁸

¹⁶ Op. cit. Wood Mackenzie gas cost estimate.

¹⁷ BTU Analytics. [Rising Natural Gas Pipeline Prices and Their Impact on Tariff Rates](#). May 19, 2025.

¹⁸ West Virginia Public Broadcasting. [Mountain Valley Pipeline's final cost close to \\$10B](#). December 3, 2024.

These construction costs flow through to the shippers using the pipelines—utilities in this instance—in the form of agreements for firm transportation service. Firm transportation sounds solid, but these agreements, generally not publicly available, only guarantee shippers (utilities) space on the line, not actual methane molecules. So, utilities are paying for space, generally set at the maximum needed to run their generation facility at full output, every day for 20 years, even if they don't need that space, such as during periods of low electricity demand in the spring and fall.

It sounds complicated, and that is likely by design. Perhaps a simple example will help illustrate the issue. Dominion Energy and Santee Cooper have proposed building a 2,180 MW combined-cycle gas plant at the closed Canady's coal plant in South Carolina. The utilities say the plant will cost \$5 billion, or \$2,293 per kilowatt, a figure that has doubled in the past couple of years. But that estimate does not include the utilities' costs for underwriting the construction of three new and/or expanded pipelines to bring gas east from Texas and Louisiana to the plant site.

Two of these pipelines are interstate lines. One (called South System Expansion 4) is a \$3.5 billion project to expand Southern Natural Gas' South Main Line by 1.3 billion cubic feet per day (bcf/d).¹⁹ The second, Mississippi Crossing (MSX), is a proposal to build a new line running from East Texas to the Southeast. It will cost an estimated \$1.7 billion and be capable of transporting up to 2.1 bcf/d.²⁰ The third is an intrastate line dubbed the Bridge Project, backed by Kinder Morgan, that will run 71 miles from the Georgia-South Carolina border to the plant site. It has an estimated construction cost of \$431 million.²¹

Dominion Energy and Santee Cooper will have to pay to reserve space on all three lines, but the companies have not released details of these contracts to the public. IEEFA has estimated the cost to ratepayers of the Bridge project, as it is being built essentially to serve the new gas plant, meaning all the costs will fall on the utilities' consumers.

The South Carolina utilities have contracted for 325,000 dekatherms per day, with most (290,000 dekatherms) for the new CCGT and the remainder for Dominion's in-state gas utility. To calculate the cost of this agreement, IEEFA used a transportation rate of \$0.50 per dekatherm/day; this is slightly higher than a couple of publicly available rates, but indicative of the upward pressure on costs across the industry. That amounts to a \$59.3 million reservation fee per year for the contract period, regardless of how much of that reserved space is used. Over the 20 years of a standard transportation contract, this would total \$1.18 billion, with a net present value of \$614 million using Dominion's current weighted-average cost of capital. That amounts to 12.3% of the project's estimated cost, a sizable sum that should be factored into the resource selection process.

Importantly, this is just an estimate for the cost of one of the three pipeline projects that will be required to operate this one new gas plant.

¹⁹ Docket No. 2025-323-E, [Direct Testimony of M. Shaun Randall](#), p. 7.

²⁰ *Ibid.*, p. 6.

²¹ Kinder Morgan. [Bridge Project Fact Sheet](#). Accessed February 24, 2026.

Similar costs will be passed through to consumers on all other new pipeline construction projects, further widening the cost gap between gas and fuel-free wind, solar, and battery storage.

Competition Is Intensifying

Currently, developers of gas-fired power plants are preoccupied—in their view—with the insatiable electricity demand driven by data center growth. Their mantra is build as much as you can, as quickly as you can. This single-minded focus on the present ignores several major future financial risks.

Gas Investments Stranded Cost Risk

Gas plants are relatively long-lived assets, where multibillion-dollar investments today are designed to be paid off over their 30-year or longer lifetimes. In normal utility planning, for example, a combined-cycle gas-fired plant that comes online in 2030 would be expected to operate at least until 2060. But if the investment assumptions are flawed and the plant becomes uncompetitive sooner, it will become a "stranded asset," unable to generate sufficient returns to repay the invested capital. Then, it may have to be closed and the losses written off. Such a situation could arise from higher-than-expected construction costs (cost overruns), lower-than-expected power demand, too many power plants being built, or lower-cost competition from other generation sources.

The risk that a major gas plant investment today will be stranded in the future is particularly high given the significant uncertainty about future data center-driven electricity demand. Growth from artificial intelligence (AI)-driven data center development is real, but the highest projections are declining as utilities institute new contracting rules forcing developers to put serious financial resources behind their proposals.

AEP Ohio, which serves the city of Columbus and a large portion of the state's center, is one of the utilities that has been projecting some of the fastest data center-driven electricity demand growth in the U.S. But a new tariff for large loads in the utility's service territory has sharply changed the outlook. The utility proposed the new tariff in May 2024, telling Ohio regulators that it had received capacity requests totaling more than 30,000 MW from large-load customers (generally, but not always, new data centers).²² That sparked a year-long process culminating in the approval of its new tariff in July 2025. The tariff requires new large-load customers to contractually commit to pay for at least 85% of their requested capacity for as many as 12 years, even if they don't use it all.²³ The tariff has had an immediate impact. In September 2025, AEP Ohio reported to state regulators that it had received requests, backed by financial commitments, from 36 data centers to study new load totaling

²² [Ohio Power tariff application](#). Case No. 24-508-EL-ATA. May 13, 2024, p. 4.

²³ [Office of the Ohio Consumers' Counsel](#).

just over 13,000 MW of capacity.²⁴ In other words, forcing developers to put some skin in the game quickly separates real proposals from aspirational ones.

That is still a significant number, but it highlights the benefits of using flexible, smaller, and quicker-to-market resources to meet most, if not all, of this projected growth, particularly in the short term. Wind, solar and storage, generally built in smaller segments and much quicker from initial proposal to commercialization, can be brought online as needed as demand grows, shielding customers from massive utility overbuilding and subsequent stranded cost risks.

Customers may also be forced to pay high stranded-gas-plant costs in states such as Maryland, Virginia, and North Carolina that have existing decarbonization legislation. Gas plants coming online now, or more likely in 2030 or later due to the lengthy wait times for new turbines, would have years left in their operating life if they are closed by 2050 (a common end date for many state clean energy plans). The unrecovered construction costs from those plants, which would total billions of dollars, almost certainly would be recovered from utility ratepayers. Renewable resources do not face these same threats, making them a better option for utilities and ratepayers alike.

The Rise of Battery Storage

A Clear Cost Winner

Notwithstanding the clear financial benefits of solar and wind—lower capital outlays and no fuel-cost risks, in particular—opponents have consistently criticized renewables for being non-dispatchable. Battery storage, especially grid-scale installations, changes that, and does so cost-effectively. Batteries can be charged from any energy source (including gas), but battery operators consistently seek power at the lowest-cost times of day, which is generally when solar and wind output are high and driving wholesale electricity prices down. Battery operators also seek to profitably resell that power at times of the day when prices are high, usually when renewable output falls, demand rises, and higher-priced fossil-fueled power kicks in. In short, battery storage is soaking up low-cost renewable power while displacing higher-cost coal and gas power when it discharges that power back to the grid.

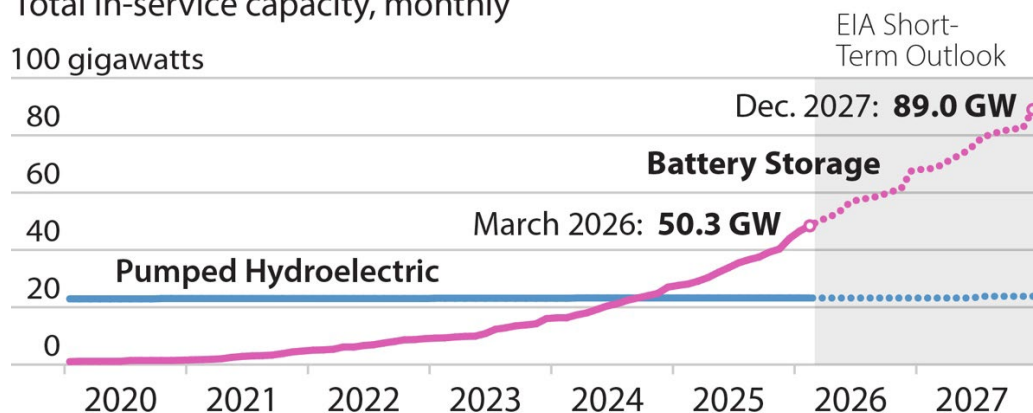
It should come as no surprise, then, that dispatchable battery storage capacity is growing extremely quickly.

²⁴ [AEP filing to PUCO](#). Case No. 24-508-EL-ATA. Sept. 11, 2025.

Figure 3: U.S. Battery Storage Installations Hit 50GW and Are Growing Quickly

Total in-service capacity, monthly

100 gigawatts



Source: EIA Short-Term Energy Outlook, March 2026

In its 2025 LCOE report, Lazard estimates the low end of firm onshore wind and solar at \$44/MWh and \$50/MWh, respectively—less than half the cost of a new combined-cycle gas plant at the current estimated capital cost of \$2,500/kW.²⁵ Even using the midpoint of Lazard’s estimates for both firm onshore wind and solar, which are \$83.50/MWh and \$90.50/MWh, the cost of dispatchable renewables is well below the now much-higher projected cost for new gas generation.

Lazard is not alone in its favorable cost forecasts regarding firm renewables. In a review of wind and solar projects paired with storage, using data through 2024, Lawrence Berkeley National Laboratory (LBNL) reported that the unsubsidized power cost for hybrid projects was \$87/MWh, with the storage component being \$36/MWh.²⁶ Looking at power purchase agreements (PPAs), LBNL said the average power price for solar-plus-storage projects in 2024 and early 2025 was \$75/MWh.²⁷ While up from lows posted earlier this decade, it is still significantly lower than the cost of new gas.

Batteries Boost System Flexibility

The benefits of batteries to system performance are evident in California and Texas, two disparate electricity markets that have been early movers in storage. California now has 15,810 MW of installed battery storage capacity;²⁸ Texas has 16,666 MW.²⁹ Prior to the COVID-19 pandemic that began in 2020, there was almost no storage in Texas and less than 1,000 MW in California. That growth is changing how both grids operate.

²⁵ Lazard LCOE. June 2025.

²⁶ LBNL. [Hybrid Power Plants: Status of Operating and Proposed Plants](#). October 2025.

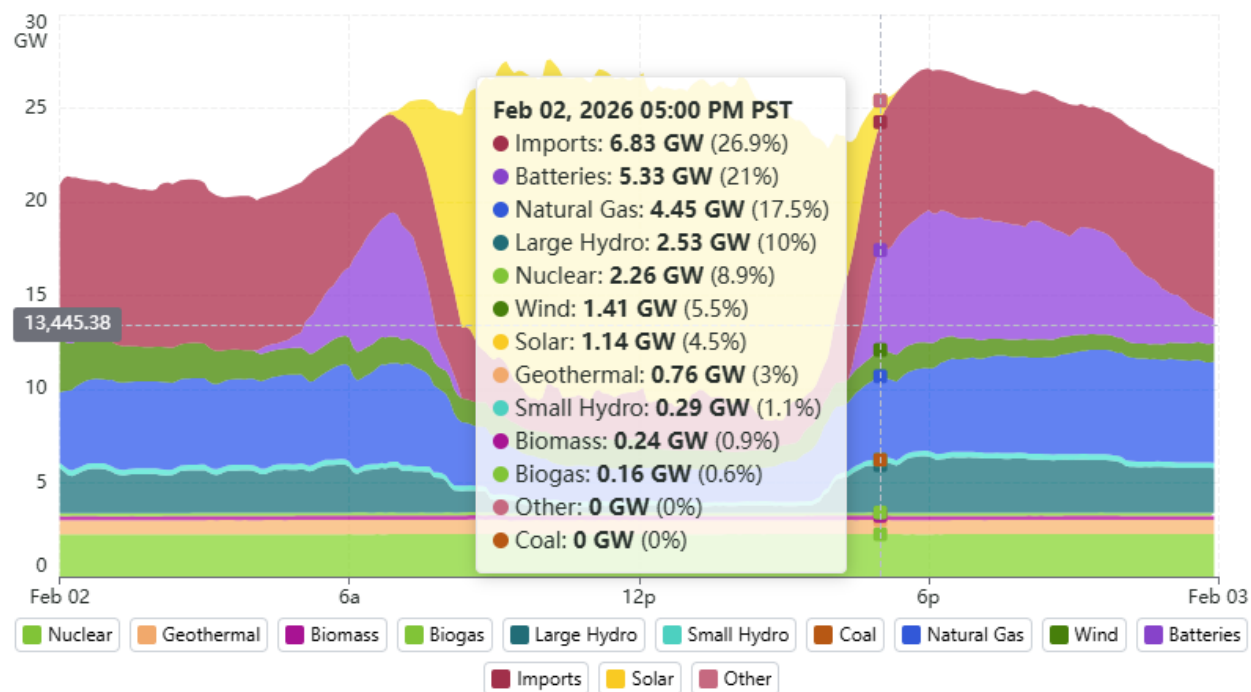
²⁷ *Ibid.*

²⁸ CAISO. [Key Statistics](#). December 2025.

²⁹ ERCOT. [Resource Capacity Trend Charts](#). January 2026.

In California, as the graphic below illustrates, battery storage is serving as an important capacity resource by charging up during the day and then sending power back to the grid in the evening as the sun sets and in the early morning before the sun rises. On Feb. 2, battery storage met 20% of total CAISO demand starting at 5 p.m. and continuing until 9:55 p.m., providing power that likely would have come from the system’s gas-fired generators in years past.³⁰ The comparison to the same day in 2021, which had approximately the same evening peak demand of just over 27,000 MW, is startling. During the 2021 peak, gas and imports accounted for 73.5% of CAISO demand, and there was no battery storage on the grid. In 2026, gas and imports accounted for 45.6% of demand at the peak, down from the previous year due to the sharp increase in battery storage. This year, during the Feb. 2 evening peak at 6 p.m., dispatchable battery storage alone met 26.2% of CAISO demand.

Figure 4: Battery Storage Is Significantly Reducing California Gas Generation



Source: [GridStatus.io](https://gridstatus.io)

Power delivered from batteries (purple areas) in both morning and evening periods would have been gas generation just 3 or 4 years ago.

The transition is equally visible in Texas, which was the fastest-growing state for electricity demand over the past decade. The peak day for the Electric Reliability Council of Texas (ERCOT) last summer was Aug. 18, when demand reached 83,877 MW just before 5 p.m.. But the crucial period

³⁰ Data in this section is from [GridStatus.io](https://gridstatus.io); accessed February 10, 2026.

for system operators occurred several hours later as the sun set and demand remained high. At that point, ERCOT's battery storage facilities ramped up quickly, boosting output by 5,000 MW in 50 minutes, helping to cut the need for additional gas generation and reduce prices. The system's real-time price fell from \$204.52/MWh at 7 p.m. to less than \$100/MWh just seconds later, as battery capacity began to feed into the grid.³¹

These two examples show that battery storage works, and it is a resource that many companies are moving quickly to exploit. John Ketchum, CEO of NextEra Energy, is one of those sold on batteries' capabilities. During the company's first quarter earnings call in January, he pointed to the obvious: "Nearly every region in the country needs capacity, and battery storage is the only new capacity resource available at scale."³²

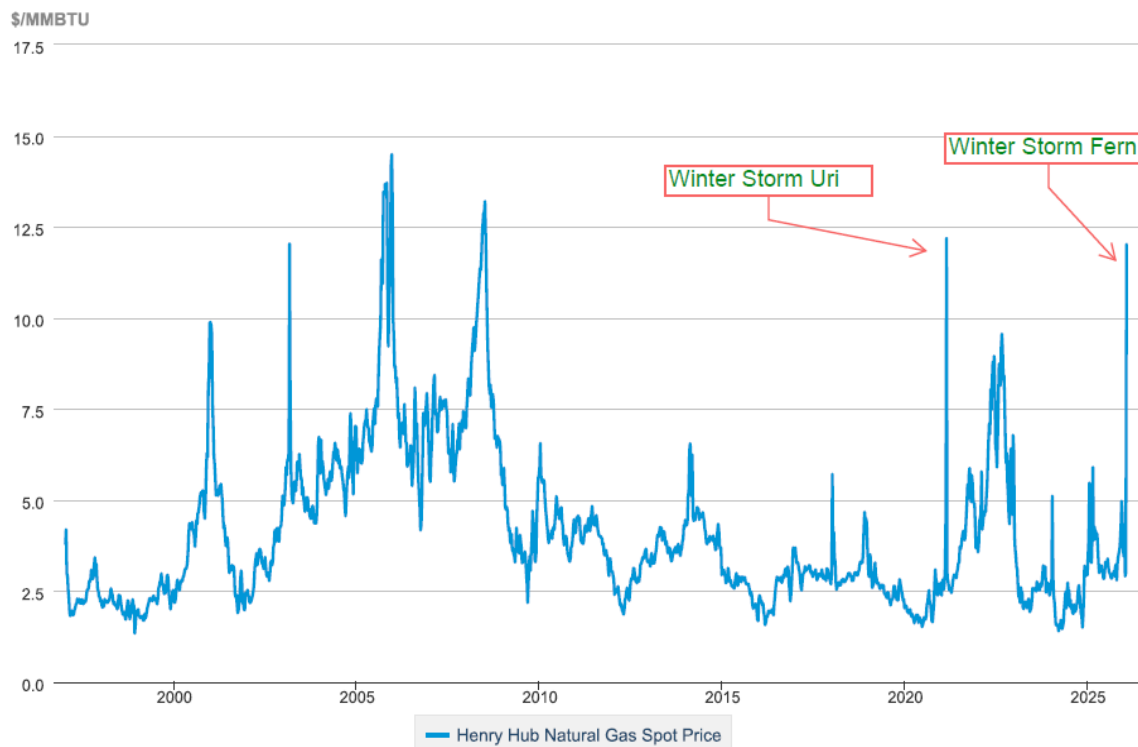
Ketchum sees major potential for NextEra here, estimating that the company's battery storage pipeline could top 95 gigawatts (GW), including both new standalone projects and co-located storage at sites where the company already has a grid connection.³³

In addition to its potential as a capacity resource, battery storage can play a significant role in reducing the commodity fuel risk discussed in the previous section. Just last month, during Winter Storm Fern, which blanketed much of the eastern U.S. with significantly below-normal temperatures, Henry Hub prices for the week ended Jan. 23 averaged \$12.02 per MMBtu, the highest weekly price at the hub since Winter Storm Uri in February 2021. During cold weather events like those, utilities cannot reduce their generation to save on fuel costs, given high electricity demand. The result is high consumer costs. Battery storage can help reduce those fuel costs and, by extension, save consumers money.

³¹ Price and battery discharge data is from [GridStatus.io](https://www.gridstatus.io); accessed February 10, 2026.

³² NextEra Energy. [Fourth quarter 2025 earnings call transcript](#). January 27, 2026.

³³ *Ibid.*

Figure 5: Weather, Geopolitical Spikes in Gas Prices Are Costly for Consumers

Source: EIA

Batteries Getting Bigger and Better

Finally, this is just a snapshot of where batteries are today, not where the technology is headed. Their costs are projected to continue falling, while their energy storage capacity improves. An enormous amount of global R&D investment is focused on improving batteries—for consumer electronics, for electric vehicles, and for grid-scale and consumer energy storage. This research has led to consistent improvements in energy density (more power in the same amount of space), lower costs, and safer chemistries. It almost certainly will continue to do so in the future.

Renewables—Available Now, Faster To Build, Easier To Scale

The reality is that expensive new gas-fired power plants will add relatively little generation to the U.S. grid through 2030; renewables and battery storage can be built to meet rising demand projections.

Here, ERCOT is a great example. In its December 2025 outlook for future capacity additions, the system operator tallied up the renewable, battery storage, and gas generation capacity it expects online by the end of 2028. The totals are illuminating, as shown in the table below.

Table 1: Expected ERCOT Capacity Additions to 2028 (MW)

	Current Capacity (MW)	Additions by 2028 (MW)	Total (MW)
Wind	40,719	6,783	47,502
Solar	37,443	27,485	64,928
Battery Storage	16,646	20,782	37,428
Green Total	94,808	55,050	149,858
Combined Cycle	44,101	1,371	45,472
Other Gas	24,524	2,489	27,013
Gas Total	68,625	3,860	72,485

Source: ERCOT

The combined-cycle capacity being added to the ERCOT system consists of one project, CPV's Basin Ranch power plant, which is underwritten by a \$1.1 billion loan from the state government through the Texas Energy Fund.

That one plant won't meet Texas's expected demand growth. The reality is that growth will largely be met by clean, low-cost renewables and battery storage—just as it has been over the past decade. IEEFA research shows that from 2016-25, total ERCOT electricity demand rose by 136.2 million MWh; wind and solar accounted for 94.5% of this growth, totaling 128.7 million MWh.

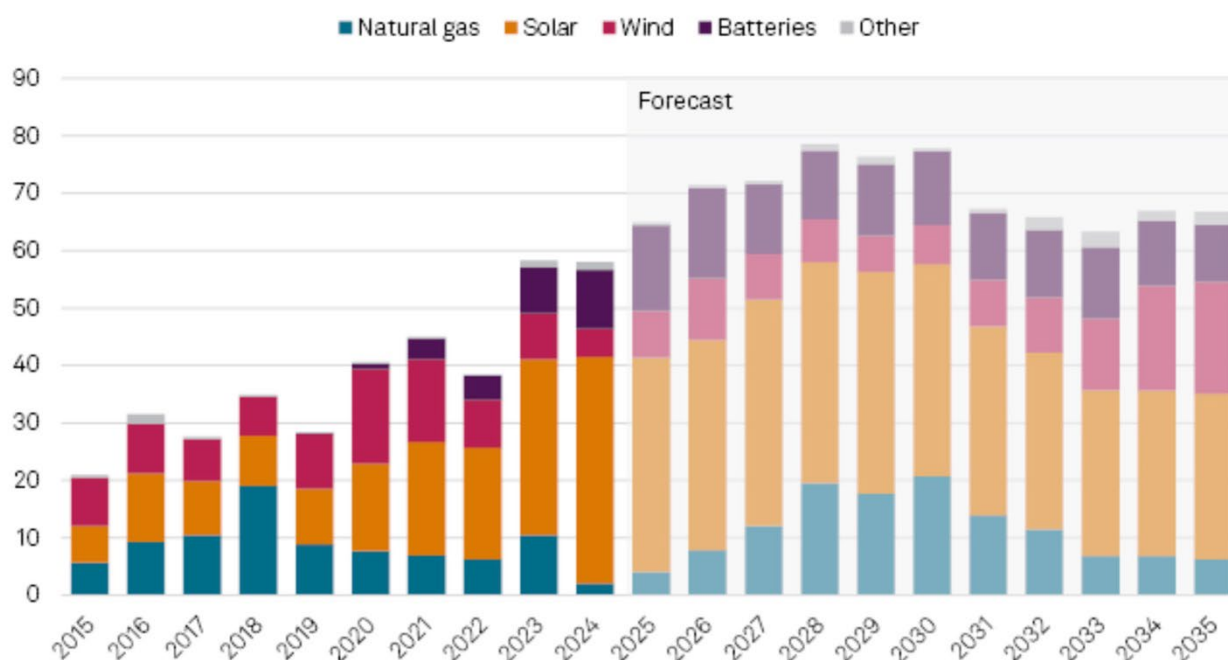
The same scenario is going to play out across the U.S., with new generation capacity in the next two years dominated by wind, solar, and storage projects, driven in part by the administration's phase-out of existing tax credits. But even farther out, most analysts project that renewables and storage will far outpace new fossil fuel additions.

There are clear headwinds for renewables at the federal level, but supply chain constraints, rising costs, and lengthy delays are hampering gas construction plans. Over the next few years, expected demand growth will support the continued renewable energy build-out.

Figure 6: Renewables and Battery Storage To Make Up Most Capacity Additions to 2035

Renewables, batteries and gas to fuel new US power supplies over next decade

Annual capacity additions in Lower 48 (GW)



Source: S&P Global, January 2026

Conclusion

New gas plants are being built in the coming years, but there is little doubt that this new capacity will entail significant financial risks for consumers, investors, and utilities.

For starters, this capacity will be significantly more expensive to build. Costs for turbines, installation, and new supply pipelines have all risen sharply in the past couple of years. These higher costs will clearly impose new burdens on consumers, and there is no clear end in sight to the constrained supply situation. The three major turbine manufacturers, GE Vernova, Siemens, and Mitsubishi, are all ramping up capacity, but they are not chasing the market, having been burned by a boom-and-bust cycle earlier this century.

Beyond hardware costs, the new gas capacity entails significant price risks for consumers. Episodic price spikes, whether weather-related or driven by international events, can push higher costs onto consumers, even if they are short-lived. These events are already surprisingly common—there have been three major ones since 2021—but they could occur even more frequently in the future. The rise in LNG exports increases price volatility in the U.S. by increasing market exposure to

international events. Similarly, the status of gas as the largest source of U.S. electricity generation has increased the potential impact of extreme weather events. Beyond this, general price increases are likely as domestic users compete for supplies amid growing LNG exports, particularly if domestic gas production fails to keep pace.

Consumers are clearly in the crosshairs, but there are significant risks in this gas stampede for developers, utilities, and investors as well.

The sharply higher infrastructure costs for new gas capacity pose significant stranded-cost risks, particularly given the availability of cheaper, quicker-to-market renewable energy and dispatchable battery storage. In addition, the uncertainty of future demand growth makes high-cost, long-lived investments in gas capacity particularly risky.

Solar, wind, and dispatchable battery storage can be built much more quickly, at lower cost, and at a scale that matches actual demand growth rather than optimistic AI-driven projections.

Renewables and battery storage are also better for consumers, providing protection against rising, volatile fuel costs and shielding them from the high cost of new gas-fired capacity.

The stampede for gas makes no sense, for consumers, investors, or utilities.

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