OPEN ENERGY OUTLOOK

The Value of New Wind and Solar for Meeting Data Center Load Growth

Costs and Emissions Through 2040 With and Without New Wind and Solar

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1 Executive Summary

U.S. electricity demand is rising at a pace not seen in decades, driven by data center growth, even as recent federal actions are narrowing the options for building new wind and solar projects. We use the open-source Temoa model to estimate the value of building new utility-scale wind and solar capacity to meet that demand growth through 2040. We compare an unconstrained, least-cost system, in which the model can build any available power-generation technology, with a most extreme case, based on the current policy direction, in which no new utility-scale wind or solar can be built beyond 2026 levels (the no-new-renewables case). For this analysis, we use the Electric Power Research Institute (EPRI)'s reference projection of data center load. The ability to build new utility-scale wind and solar makes the system both cheaper and cleaner. Without it, the 2040 average marginal cost of supply would be about 12 percent higher, greenhouse gas emissions would be about 50 percent higher, and emissions of sulfur dioxide and nitrogen oxides would increase. The value of new wind and solar is greatest in the central and southern regions, which have the highest-quality wind and solar resources. These findings hold across low, reference, and high data-center demand levels.

2 Background and Motivation

U.S. electricity demand is growing at a pace not seen in decades, driven by data center buildout, electrification, and manufacturing reshoring. Meeting this demand will require substantial new generation capacity. In recent work, we showed that data center and cryptocurrency demand could materially raise U.S. power system costs and emissions through 2030, with effects that vary widely by region (Johnson et al. 2026).

At the same time, the energy policy environment has shifted sharply since January 2025, with most of the impact falling on wind. The first move was legislative. The One Big Beautiful Bill Act, signed July 4, 2025, ended the tax credits for wind and solar; projects placed in service after 2027 no longer qualify unless they began construction by July 4, 2026 (Fishman et al. 2025). Executive action against offshore wind followed. A January 2025 presidential memorandum withdrew Outer Continental Shelf areas from leasing and paused permits, and the administration then issued stop-work orders on projects already under construction and suspended five operating leases on national security grounds. Federal courts have repeatedly reversed these actions (Harvard Environmental and Energy Law Program 2026), so the Interior Department has instead begun paying developers to abandon valid leases, with TotalEnergies, Bluepoint Wind, and Golden State Wind accepting buyouts and reinvesting in oil, gas, and LNG (DOI 2026).

Renewable permitting has tightened alongside these moves. A July 2025 order required the Interior Secretary to personally approve every wind and solar project on federal lands and waters (Daly 2025), while the Defense Department halted once-routine reviews for onshore wind on private land, stalling about 165 projects, or roughly 30 GW (Nilsen 2026; Mulder 2026). At the same time, the administration increased its support for coal power, using emergency authority to keep aging units running beyond their previously announced retirements and announcing up to $850 million to modernize coal capacity and to build two new plants (DOE 2026b, 2026a; Walton 2026). In August 2026, a federal court found that the Defense Department's halt to permitting was unlawful under the Administrative Procedure Act and ordered the Department to resume the reviews (Tamborrino 2026). Similarly, courts have ruled against the administration's order to keep some coal plants open (Daly 2026). The current Executive interventions are unlikely to halt renewable expansion entirely, in part because the most likely substitute for constrained renewables is itself supply-limited: gas turbine backlogs stretch toward the early 2030s, plant costs have climbed sharply, and the EIA has revised its near-term gas price outlook upward (Lanfranchi 2025; Chant 2026; EIA 2026). Nonetheless, the cumulative direction of these recent Executive actions raises a question that our analysis is designed to answer: What is the value of the ability to build new wind and solar to a power system that must meet rapid data center growth? Using a cost-optimal capacity expansion model, we evaluate the cheapest mix of new generation, storage, and transmission to meet U.S. electricity demand through 2040 across three data center load trajectories, each simulated once with unconstrained resource choices and once under a constraint prohibiting new utility-scale wind and solar beyond 2026 levels. The results suggest that the ability to build new wind and solar lowers the cost of meeting demand and reduces emissions of greenhouse gases and criteria air pollutants.

3 Methods

3.1 The model

We use Temoa (Tools for Energy Model Optimization and Analysis), an open-source energy system model, to study how the U.S. electricity sector could meet rising demand at the lowest cost. The model determines how much generation, storage, and transmission to build, and how to dispatch them hour by hour, capturing how the system responds to rapid load growth, such as surges from new data centers. The input database used in this analysis represents the contiguous United States as 26 regions, optimizes capacity for the model years 2027, 2030, 2035, and 2040, and dispatches the system at hourly resolution over 20 representative weeks per model year, extending the 2030 horizon of our earlier study (Johnson et al. 2026).

The model has a detailed representation of the existing fleet and can build new solar, wind, nuclear, coal, natural gas (with and without carbon capture), hydrogen, and lithium-ion storage. Technology cost and performance assumptions follow the latest NLR Annual Technology Baseline (ATB) (NLR 2026), with natural gas and hydrogen capital costs scaled to current market conditions per E3's RECOST Q1 2026 trajectory (combined-cycle costs up to roughly 1.7 times ATB, combustion turbines up to roughly 1.3 times for near-term vintages) (E3 2026). Existing units are based on EIA data on generating capacity, electricity generation, and fuel consumption, processed using the Public Utility Data Liberation toolkit and supplemented by the June 2023 EIA Form 860m. We subsequently checked installed capacities against January 2026 EIA data and updated capacities where needed. Relative to (Johnson et al. 2026), this analysis updates fuel prices to EIA's Annual Energy Outlook 2026 (EIA 2026), raises gas plant capital costs, and adopts EPRI's 2026 data center demand projections (EPRI 2026).

The model is a least-cost optimization: it finds the mix of generation, storage, and transmission that meets projected electricity demand at the lowest present value of total system cost, including capital, fuel, and operating costs. It represents a single central planner and does not capture firm-level investment decisions, market structures, interconnection queues, permitting timelines, or supply-chain limits. Its results, therefore, indicate what is technically and economically feasible for the power system as a whole, rather than forecasting what individual developers and markets will actually build. The analysis also excludes any federal or state tax credits or subsidies, so the cost comparisons reflect the underlying capital, fuel, and operating costs of each technology on its own. The model reports the cost of building and operating the system as a whole, not the revenues, profits, or retail bills of individual plants or customers. How these system costs translate into wholesale prices and monthly electricity bills depends on market structures and cost-allocation rules that lie outside the model.

3.2 Load scenarios

We base electricity demand on EPRI's Powering Intelligence report, which projects U.S. data center electricity use through 2050, covering our full study period. Data centers consume about 4 to 5 percent of U.S. electricity today, and EPRI projects this share could reach 8 to 17 percent by 2030 and keep climbing through 2040 (EPRI 2026). EPRI varies one main assumption, how many announced and planned projects come online, producing low, central, and high trajectories. Our main analysis uses the central trajectory, which we refer to as the reference load. In this scenario, data centers account for about 13 percent of national electricity demand by 2040.

3.3 Two build cases

We run each load trajectory under two cases, for a total of six model runs. In the unconstrained case, the model constructs the least-cost mix without technology limits. In the

no-new-renewables case, we freeze both utility-scale wind and solar capacities at 2026 levels for all future years. We use “no new renewables” as shorthand for this scenario: wind and solar are the only renewable resources the model adds in either case, so in practice, this case adds no new utility-scale renewable capacity. Solar capacity still grows in this case (from about 200 GW in 2027 to 257 GW in 2040) because distributed generation, mostly rooftop solar, is defined exogenously in every case. Existing utility-scale solar is assumed to remain at about 153 GW. This case also removes the policies that would otherwise mandate renewable energy construction, namely state renewable and clean energy standards, offshore wind procurement targets, and the RGGI cap on power-sector CO_2 emissions, because the optimization would not otherwise be feasible. No official moratorium on new wind and solar power exists, and developers continue to invest in these projects, so this case is not a forecast but a representation of the impacts of a most extreme case of wind and solar restrictions. We measure the value of new utility-scale wind and solar as the difference in costs, emissions, and system composition between the two cases.

3.4 Sensitivity analysis

The pace of data center growth is uncertain, so we repeat both build cases under EPRI’s low and high trajectories, which reach about 8 and 18 percent of national demand by 2040 (EPRI 2026). These runs bracket the plausible range of data center load and test whether the main conclusions hold across it.

4 Results

4.1 Capacity

Both the unconstrained and no-new-renewables cases meet the same reference demand in 2040, but they build very different systems to get there (Figure 1). In the unconstrained case, the least-cost system leans heavily on renewables: solar grows from 210 GW in 2027 to about 620 GW by 2040, and wind from 195 GW to about 470 GW, while natural gas grows only modestly from 465 GW in 2027 to about 475 GW in 2040. Finally, batteries reach about 110 GW in 2040 (up from 45 GW in 2027). When new wind and solar are capped at 2026 levels, natural gas fills the gap, increasing to about 630 GW and becoming the largest single resource, while wind holds near 155 GW and solar reaches about 255 GW. Gas then supplies about 40 percent of national capacity, up from under 25 percent.

Nuclear (about 100 GW), hydro (about 165 GW), and the existing coal fleet (about 160 GW) barely move between cases. Coal capacity remains roughly constant in both cases because these plants are already built and available, and strong demand growth leaves little economic incentive to retire them early, even as wind and solar expand. The model builds no new coal in either case; the existing fleet simply keeps running. Furthermore, the model does not build new hydropower or nuclear power plants in either scenario because they are resource-limited (hydro) and cost more than new gas plants (nuclear), despite the higher installed and fuel costs assumed here for natural gas plants. Without new wind and solar, these resources remain noncompetitive; new construction simply shifts toward gas. Figure 1 highlights that the constrained system is smaller: total capacity reaches about 1,580 GW by 2040 (up from roughly 1,300 GW), roughly a quarter below the unconstrained 2,100 GW, even though both serve the same load. The reason is capacity factors and utilization. Wind and solar produce only when the resource is available, so a renewable-heavy fleet needs more nameplate capacity to deliver a given amount of energy, whereas gas can run around the clock. The constrained system, therefore, meets demand by running its gas fleet much harder.

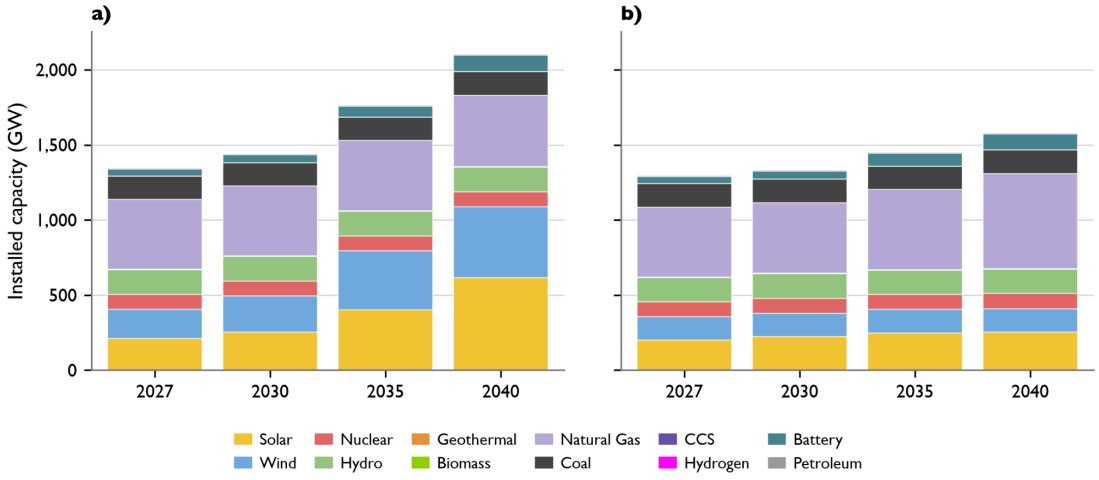


Figure 1: National installed capacity by resource in the unconstrained scenario (a) and the scenario with no new renewable development beyond 2026 levels (b).

4.2 Generation

Both cases generate the same total amount of electricity in 2040, roughly 6,700 TWh (up from

4,500 TWh in 2027), because both serve the same demand; what changes is how that energy is produced (Figure 2). In the unconstrained case, wind and solar do most of the work by 2040, together generating about 3,000 TWh, or roughly 45 percent of the total, with 1,355 TWh of natural gas generation, 1,150 TWh of coal, 865 TWh of nuclear, and 280 TWh of hydropower. When new utility-scale wind and solar are capped, gas takes over, rising to about 3,240 TWh in 2040, more than double its unconstrained level and close to half of all generation. Wind and solar together produce only 960 TWh in 2040 in the constrained scenario, accounting for around 14 percent, while coal generation increases from about 1,150 TWh in 2040 in the unconstrained scenario to about 1,340 TWh in the constrained scenario, as the existing coal fleet runs more hours. Nuclear and hydro barely change.

The central result is one of utilization, not capacity. The smaller constrained fleet leans far harder on the plants it has: the gas fleet's average capacity factor increases by about 80 percent, from about 33 percent in 2040 in the unconstrained case to about 58 percent under the no-new-renewables scenario, and coal runs at higher rates as well. Without new wind and solar, the system changes not only what it builds but also how hard the existing fossil fleet must run, which drives the higher costs and emissions discussed below.

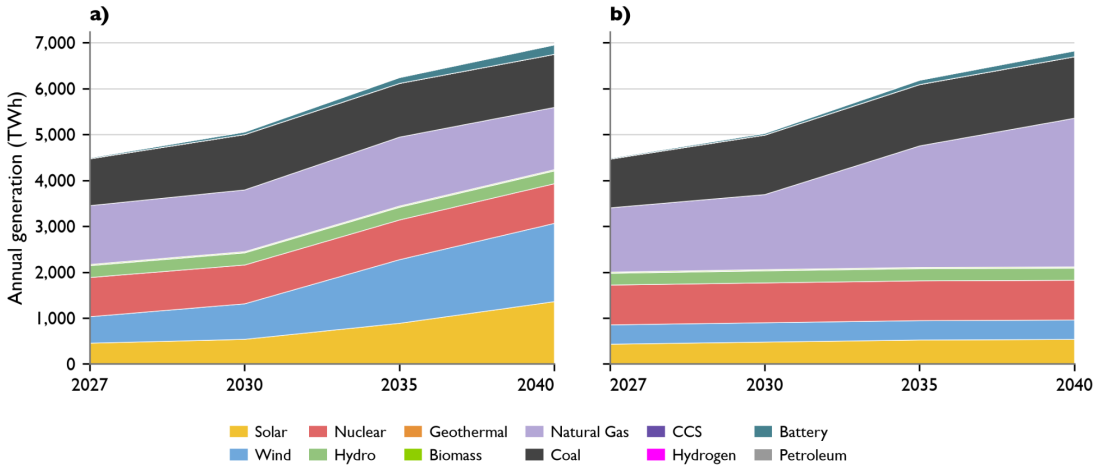


Figure 2: National generation by resource in the unconstrained scenario (a) and the scenario with no-new-renewables development beyond 2026 levels.

4.3 Regional Effects

The national shift from renewables to gas in the no-new-renewable scenario plays out in every region. The largest change in installed generating capacity is in the East (outside PJM and MISO), where 2040 gas capacity is about 43 GW higher under the no-new-renewables case, while the combined solar and wind capacity decreases from 357 GW in the unconstrained case to about 108 GW in the no-new-renewables case. Elsewhere, the 2040 gas difference between the scenarios ranges from about 12 GW in ERCOT to about 36 GW in PJM. Thus, the impact of the constraint on renewable resources varies across US regions. In the West and PJM, the constraint primarily limits solar power installation, while ERCOT and MISO see a substantial decrease in wind capacity when the constraint becomes binding. Full regional capacity by resource is available on the online dashboard accompanying this report.

Total generation also shifts geographically. Output in the constrained scenario rises most in the PJM and Ohio Valley region, where gas, coal, and nuclear capacity sit close to fast-growing data center load, and generation falls in renewable-exporting regions such as Texas and California, which generate less once their new wind and solar cannot be built. Without new wind and solar, therefore, electricity generation concentrates in fossil-heavy regions near eastern demand centers. Regionally, the largest swings in generation occur where renewables lead in the unconstrained scenario: In 2040, ERCOT and the West generate 56 - 64% from wind and solar in the unconstrained case, falling to 20 - 30% under the no-new-renewables case, while PJM's wind and solar share nearly disappears (31% to about 6%). Across all

regions, the share of total electricity produced in 2040 with gas and coal rises to between 60% and 76% of the mix once renewables are capped. The full regional generation mix is available in the dashboard.

The reduced capacity and generation from wind and solar under the no-new-renewable scenario also reduces the need for inter-regional transmission. Total inter-regional transfer capacity in 2040 reaches about 394 GW in the unconstrained case versus about 356 GW in the no-new-renewables case, roughly 10% less. In the unconstrained case, the model builds new lines to carry wind and solar from resource-rich areas to distant load centers; when those renewables cannot be built, the system instead places gas near demand, so most corridors carry less capacity and power, with a few in the central United States and Mid-Atlantic gaining. Corridor-level transmission changes are shown in the dashboard.

4.4 Costs

We compare costs using the average marginal supply cost: the cost of serving one additional megawatt-hour in each region and hour, averaged over the year and weighted by demand in each hour. This cost reflects both the fuel cost of the marginal plant and the annualized investment cost of the capacity needed to serve the load, capturing the full long-run cost of supply rather than fuel cost alone. It is the shadow cost on each region's demand-balance constraint, which is related to but not the same as a market locational marginal price. Nationally, the load-weighted annual average marginal supply cost in 2027 is $32/MWh. By 2040, in the unconstrained scenario, in which renewables can be built, the load-weighted annual average marginal supply cost increases to $37/MWh. By contrast, in the constrained scenario limiting the expansion of wind and solar, the load-weighted annual average marginal supply cost in 2040 is $42/MWh. These cost impacts vary geographically.

Figure 3 maps the 2040 marginal supply cost. In the unconstrained case, costs are lowest in the wind-rich central plains at around $30 per MWh and highest in the New York City area at just above $50 per MWh. The cost of the constraint is not shared evenly: the largest increase between the unconstrained and no-new-renewables scenarios, roughly $11 to $13 per MWh, falls on the central United States, including the Great Plains, the Mountain West, Texas, and the Southwest, the regions that rely most on new wind and solar in the unconstrained scenario and are therefore forced to more expensive gas. The marginal supply cost in several eastern regions changes little or is slightly lower under the constrained scenario. The slight drop in cost is attributable to the elimination of regional and state renewable mandates and the carbon cap and trade program. New wind and solar provide the greatest value in the regions with the best wind and solar resources.

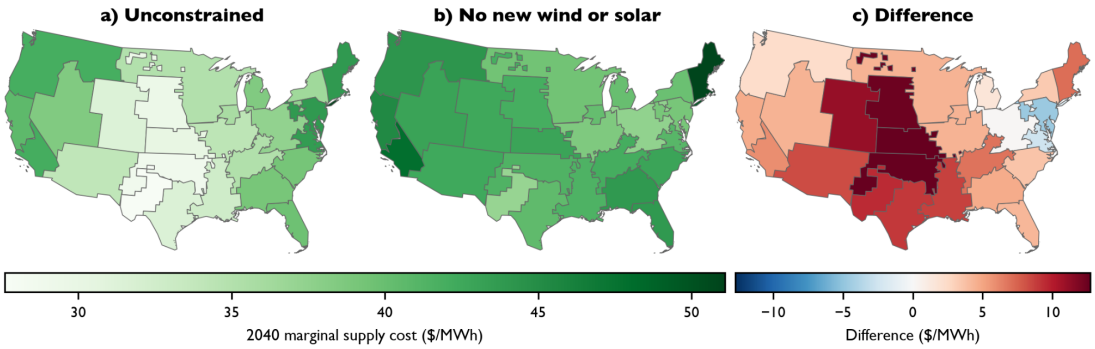


Figure 3: 2040 marginal supply cost by region in the unconstrained scenario (a) and the no-new-renewables scenario (b). Panel (c) shows the difference between the two scenarios.

4.5 Emissions

Power-sector greenhouse gas (GHG) emissions (CO_2, CH_4, and N_2O) are directly driven by the generation mix. In the unconstrained case, national GHG emissions (measured in Mt of CO_2-equivalent) rise only modestly between 2027 and 2040 (even as demand grows sharply), from about 1,540 Mt in 2027 to 1,720 Mt in 2040, about 12 percent, because new wind and solar serve most of the added load. In the no-new-renewables case, GHG emissions rise from

about 1,630 Mt of CO_2-equivalent in 2027 to 2,580 Mt in 2040, an increase of about 58 percent, as gas and the existing coal fleet meet the growth in demand.

The same fossil-heavy shift raises criteria air pollutants, which affect local and regional air quality, and their drivers differ by fuel. Sulfur dioxide emissions increase with coal use, since gas plants emit almost no sulfur, so the increase traces the extra hours run by the existing coal fleet. Nitrogen oxide emissions in the constrained, no-new-renewables scenario increase from two sources: a large increase in gas generation and additional coal output. Because gas generation more than doubles in the constrained scenario and occurs in nearly every region, the increase in nitrogen oxides is more widespread than the increase in sulfur dioxide, which remains concentrated where coal burns. Table 1 reports national 2040 emissions of sulfur dioxide, nitrogen oxides, and fine particulate matter (PM2.5) in both cases. PM2.5 emissions are about 35 percent higher in the no-new-renewables case.

The constraint on new renewables raises emissions in nearly every region. GHG and nitrogen oxides emissions increase broadly because gas generation rises nationwide compared to the unconstrained scenario, with the largest gains in the eastern interior spanning PJM and the Ohio Valley, in Texas, and across the upper Midwest. Sulfur dioxide changes are smaller and more localized, concentrated in the coal-reliant regions of the Mid-Atlantic, the Ohio Valley, and parts of the Midwest, since only coal emits meaningful amounts of sulfur dioxide. Regional emissions maps for all three pollutants are available in the dashboard.

Table 1: National emissions of criteria air pollutants in 2040 under the reference data center load, unconstrained, and no-new-renewables cases. Values are rounded to the nearest 5 kt; percentage changes are calculated from unrounded model results.

Pollutant	Unconstrained (kt)	No-new-renewables (kt)	Change
Sulfur dioxide (SO2)	995	1,210	+22%
Nitrogen oxides (NOx)	910	1,310	+44%
Fine particulate matter (PM2.5)	125	170	+35%

4.6 Sensitivity analysis

The value of new wind and solar holds across the plausible range of data center growth (Table 2). Across the demand scenarios, the no-new-renewables case requires between 120 and 184 GW more gas capacity by 2040, has 47 to 52 percent higher 2040 greenhouse gas emissions, and has a 9 to 17 percent higher national average 2040 marginal cost of supply.

Table 2: 2040 outcomes in the unconstrained and no-new-renewables cases under three data center demand trajectories. Values are rounded; percentage changes are calculated from unrounded model results.

Data center load	2040 gas capacity (GW)	2040 GHG (Mt CO2e)	2040 National Load-Weighted Supply Cost ($/MWh)
Low	470 to 590 (+26%)	1,670 to 2,450 (+47%)	$36.0 to $42.3 (+17%)
Reference	475 to 630 (+33%)	1,720 to 2,580 (+50%)	$37.4 to $41.9 (+12%)
High	490 to 680 (+37%)	1,780 to 2,700 (+52%)	$38.3 to $41.9 (+9%)

5 Discussion

Current energy policy rhetoric holds that wind and solar cannot support the grid needed to serve data-center-driven load growth, and that meeting this growth requires new fossil-fuel capacity (FPC Briefing 2025). Our results do not support that claim. In the unconstrained scenario, the least-cost system largely meets the growing data center demand with new wind and solar, supported by expanded energy storage, at lower cost and with lower emissions than the system that cannot build such resources. The unconstrained grid is both less expensive and lower-emission. The question is not whether renewables can support data center growth, but how much that ability is worth. In the reference case, building wind and solar lowers the 2040 national average marginal cost of supply by about $4.50 per MWh and 2040 greenhouse gas emissions by about 860 Mt, or one third.

The savings enabled by renewables reach a broad set of consumers. Because marginal supply costs fall in most regions when renewables can be built, preventing the deployment of new wind and solar resources would increase the cost of supply, which would ultimately be borne by residential, commercial, and industrial customers, not only by the data centers that drive the new demand. Without new utility-scale wind and solar, the cost of serving load would increase across most of the country, with the steepest increases in the central and southern regions, which have the best wind and solar resources.

The value of wind and solar power is not only economic. New wind and solar displace coal and gas generation that would otherwise raise levels of sulfur dioxide and nitrogen oxides, which harm health in and downwind of the communities where that generation runs. Those communities bear a health burden on top of higher electricity costs, and the two overlap in the industrial Midwest, the Ohio Valley, and parts of the South.

On greenhouse gas emissions, two findings stand out. First, data center growth is large enough that emissions rise modestly through 2040 even in the unconstrained case because demand grows faster than the grid decarbonizes without policy drivers. This growth in emissions would have implications for longer-term decarbonization goals, such as net zero targets, that fall outside the scope of this analysis. Second, limiting the development of new wind and solar turns that modest increase into a large one. Power-sector emissions grow by about 60 percent between 2027 and 2040 in the constrained case, compared with about 12 percent in the unconstrained case.

A common critique of renewables is that the renewable pathway relies more on transmission, which is costly and hard to build. Our results account for these costs: the model pays for the transmission it builds, and the unconstrained case builds more of it. Even so, the savings from wind and solar more than offset those transmission costs, so the unconstrained system is cheaper overall than the constrained system that needs fewer lines. The ability to site and pay for new required transmission determines how much of the renewable savings the system can capture. FERC Order No. 1920, as modified by Order No. 1920-A, directs that the cost of new regional transmission be allocated to those who benefit from it, in rough proportion to those benefits (FERC 2025). Our results speak directly to that principle: building renewables lowers costs in most regions, so the benefits of the enabling transmission are widely shared rather than confined to a few areas. A cost allocation that reflects this broad benefit would help the lines that unlock those savings get built.

These results describe what is cost-optimal, not what current market and regulatory conditions will necessarily deliver. In practice, most new data centers announced today are being paired with natural gas, and announcements of new gas plants have surged (Taft 2026; Day et al. 2026). Several real-world factors explain the gap between the model's least-cost fleet and

what developers are building. There is no formal moratorium on renewables, but the federal actions described earlier in this report are creating roadblocks that are already slowing new development, wind most of all. Beyond federal policy, building the transmission that a renewable-heavy system needs is difficult in the United States for reasons that go well beyond cost, and interconnection queues are severely backlogged. PJM alone has hundreds of gigawatts of mostly renewable capacity waiting to connect to the grid. Because wind and solar are more geographically dispersed than gas, siting, transmission, and interconnection constraints fall especially hard on them, limiting how quickly they can be deployed. Even so, and despite federal efforts to discourage them, renewable investments have continued to grow.

When technologies are evaluated solely on cost and performance, wind and solar can clearly play a significant role in meeting data center demand while lowering costs. Achieving such an outcome depends on a regulatory and market structure that lets renewables be built and connected to the grid. The rules governing permitting, interconnection, and transmission, therefore, determine how much of the value of new wind and solar the power system can capture. Additional barriers to their deployment reduce that value, raising costs and emissions across most of the United States.

6 References and Data

An interactive dashboard with the full national and regional results, including all figures and tables in this report, is available online at https://openenergyoutlook.org/dashboards/. Model documentation for the Temoa framework is available at https://temoaproject.org/.

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7 About the Open Energy Outlook Initiative

The Open Energy Outlook (OEO) Initiative is a collaboration between the Scott Institute for Energy Innovation at Carnegie Mellon University and North Carolina State University.

What is the Open Energy Outlook Initiative? The OEO Initiative examines the technologies and policies influencing U.S. energy futures, simulating energy technology deployments, sources, costs, and the emissions associated with meeting energy demands. We conduct rigorous research using open-source models that promote transparency, accessibility, and replicability. We also collaborate with diverse stakeholders to identify consensus-based strategies to meet energy and climate goals.

Why do we need energy systems models? Energy systems are complex, involving millions of interconnected technologies influenced by markets, policy, and consumer and firm behavior. Energy systems models excel at capturing technology performance and interconnectedness under different policy designs. Results provide robust insight into the costs, risks, and tradeoffs of alternative energy futures. Evaluating strategies to reduce the impacts of climate change is an exemplary model application.

How does OEO conduct analyses? OEO maintains a database that describes 3,000 end uses and 80,000 processes that shape the U.S. energy system. Employing the Tools for Energy Model Optimization and Analysis (TEMOA), the team builds models that simulate the least-cost set of energy sources and technologies that meet future demands, emission goals, and other potential criteria of interest.

What makes TEMOA/OEO different? TEMOA and OEO are both fully "open" and freely available on GitHub. An academic review of 31 open-source models found TEMOA among the best for long-term energy systems planning (Groissböck, 2019). Most competing models assume a fixed set of future end-use technologies, limiting opportunities to identify beneficial fuel switching (e.g., electrification). TEMOA stands out for dynamically selecting end-use technologies. TEMOA can model the entire energy system, including energy source extraction, fuel transportation and storage, electrification, and energy consumption in buildings, transportation, and industry. TEMOA can also model uncertainty and variability, making it a more robust decision support system. Importantly, OEO is more than just a model. OEO is an initiative committed to transparency, replicability, and building a user community. We published our first Open Energy Outlook report in 2022.

What kinds of scenarios are evaluated by TEMOA/OEO? Recent or ongoing OEO studies include simulations of net zero emissions pathways, estimating the impacts of the Inflation Reduction Act, exploring alternatives for incentivizing hydrogen, and simulating a carbon price. We are also applying novel techniques to identify near-least-cost strategies to achieve Net Zero emissions, thereby introducing flexibility into decarbonization decisions.

Could you benefit from OEO? Climate change and decarbonization introduce deep and novel uncertainties into the decisions of diverse stakeholders. The stakes are particularly high for organizations like energy utilities, clean energy and end-use technology companies, non-governmental organizations, policymakers, and large energy users. The OEO framework offers many possibilities for related analyses. We are actively seeking members to join our

corporate partnership. Contact OEO at mfb@andrew.cmu.edu if you are interested.

We are also always eager to collaborate with others who can complement our work. While least-cost energy transitions provide an important guidepost, they are not always realistic. Achieving our energy and climate goals requires understanding which energy transition pathways are feasible and acceptable, to whom, and why. We are particularly interested in collaborations related to labor, equity, material flow analysis, behavior, and risk analysis.

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How can I learn more? Learn more about OEO by visiting our website at www.openenergyoutlook.org.

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