U.S. House Committee on Energy and Commerce
Subcommittee on Energy
“Scaling for Growth: Meeting the Demand for Reliable, Affordable Electricity”
March 5, 2025
Documents for the Record

1. Letter from Industrial Energy Consumers of America, addressed to Chairman Latta and Ranking Member Castor, submitted by the Majority.
2. Letter from The Real Estate Roundtable, addressed to Chairman Guthrie, submitted by the Majority.
3. A letter from the National Association of State Energy Officials, addressed to Chairman Latta and Ranking Member Castor, submitted by the Majority.
4. A letter from IHI, addressed to Chairman Guthrie, Ranking Member Pallone, Chairman Latta, and Ranking Member Castor, submitted by the Majority.
5. Letter from Americans for Prosperity, addressed to Chairman Guthrie, Chairman Latta, and Ranking Member Castor, submitted by the Majority.
6. Letter from Stop MPRP, Inc., addressed to Chairman Latta, submitted by the Majority.
7. Report from Brattle entitled “A Wide Array of Resources is Needed to Meet Growing U.S. Energy Demand,” submitted by Ranking Member Pallone.
8. Report from NERA entitled “Electricity Price Impacts of Technology-Neutral Tax Incentives With Incremental Electricity Demand from Data Centers,” submitted by Ranking Member Pallone.
9. Letter from the American Gas Association, addressed to Chairman Guthrie, submitted by the Majority.
10. Report from the Nicholas Institute for Energy, Environment, and Sustainability at Duke University, entitled "Rethinking Load Growth Assessing the Potential for Integration of Large Flexible Loads in US Power Systems," submitted by the Minority.

Industrial Energy Consumers of America (IECA)
The Voice of the Industrial Energy Consumers

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March 3, 2025

The Honorable Bob Latta
Chairman
House Subcommittee on Energy
Washington, DC 20515

The Honorable Kathy Castor
Ranking Member
House Subcommittee on Energy
Washington, DC 20515

Re: Comments for the Record on Hearing on "Scaling for Growth: Meeting the Demand for Reliable, Affordable Electricity"

Dear Chairman Latta and Ranking Member Castor:

Had it not been for the costly sacrifice made by the manufacturing sector due to forced reduction in the use of natural gas this winter, the U.S. would have experienced brown outs or black outs. The natural gas that we would have used kept the lights on and people's homes warm. This sacrifice came at great costs to manufacturing companies.

On behalf of the member companies of the Industrial Energy Consumers of America (IECA), of which 100 percent are manufacturing companies, we urge the Committee to support legislation to expedite expanding natural gas pipeline capacity. The manufacturing sector consumes 26 percent of U.S. natural gas, which is used as feedstock and fuel, and 25 percent of U.S. electricity. Electricity cannot be used to displace our demand for natural gas.

This winter, across the country, because of inadequate natural gas pipeline capacity, manufacturing companies were forced to use less natural gas or were completely curtailed.[1] When there is inadequate pipeline capacity or power supply, manufacturing companies are always the first to be curtailed at significant costs of millions of dollars per day. While some manufacturers have back up sources such as fuel oil, propane, or coal for boilers, most do not. Cutting or shutting down production plays havoc on U.S. supply chains, including the production of national defense goods.

Each year, the crisis for U.S. manufacturing has become more severe. This winter, because of inadequate pipeline capacity, manufacturers have paid as much as $120 MMBtu for spot natural gas. That is much higher than what the EU or Asia paid for imported LNG. Higher prices due to constrained pipeline capacity also significantly increased electricity prices. Because we are price sensitive and compete globally, competitiveness is impacted.

[1] 44 Natural Gas Pipelines Require Manufacturers To Reduce/Curtail Use of Natural Gas Due to Inadequate Pipeline Capacity, https://www.ieca-us.org/wp-content/uploads/02.06.25_Pipeline-Capacity-Shortage_ENR.pdf

Congress wants manufacturing companies to reshore jobs and investments. That cannot happen without substantial increases in pipeline capacity. And much higher demand is forecasted due to power generation needed for the electrification of the economy, data centers, and increasing LNG exports.

LNG has a special negative impact because they maximize exports when the U.S. has its highest winter heating season demand. The LNG exports accelerate the reduction of U.S. natural gas inventory, which results in higher prices for both natural gas and electricity. The problem gets worse with additional LNG export capacity. The LNG 25-year contracts shift supply and price risks from countries that buy LNG to U.S. consumers. LNG contracts guarantee that other countries will receive our natural gas, and this reduces U.S. reliability and energy independence. The 25-year contracts are also being used to lock up what little pipeline capacity is available for domestic consumers. Manufacturers cannot do 25-year contracts.

It is for this reason that we have proposed an America First LNG Inventory Policy that would insulate U.S. consumers from the impacts of LNG exports.[2]

We urge this Subcommittee to support energy permitting reform and the America First LNG Inventory Policy. Thank you for your support of the manufacturing industry who employs 12.8 million people and contributes $2.8 trillion to the U.S. GDP. Thank you in advance.

Sincerely,

Paul N. Cicio
Paul N. Cicio
President & CEO

cc: House Committee on Energy and Commerce

The Industrial Energy Consumers of America is a nonpartisan association of leading manufacturing companies with $1.3 trillion in annual sales, over 12,000 facilities nationwide, and with more than 1.9 million employees. One hundred percent of IECA members are manufacturing companies whose competitiveness is largely determined by the cost and reliability of natural gas and electricity. IECA's sole mission is to reduce and avoid energy costs and increase energy reliability through advocacy in Congress and regulatory agencies, such as the Federal Energy Regulatory Commission (FERC). IECA membership represents a diverse set of industries including chemicals, plastics, steel, iron ore, aluminum, paper, food processing, fertilizer, insulation, glass, industrial gases, pharmaceutical, consumer goods, building products, automotive, independent oil refining, and cement.

[2] America First LNG Inventory Policy, https://www.ieca-us.org/wp-content/uploads/LNG-Inventory-Policy-to-Insulate-the-US-Market-from-LNG-Export-Impacts.pdf

The Real Estate Roundtable

February 26, 2025

The Hon. Tom Cole, Chairman
The Hon. Rosa DeLauro,
Ranking Member
Appropriations Committee
U.S. House of Representatives

The Hon. Susan Collins, Chair
The Hon. Patty Murray,
Ranking Member
Appropriations Committee
U.S. Senate

The Hon. Brett Guthrie, Chairman
The Hon. Frank Pallone,
Ranking Member
Energy & Commerce Committee
U.S. House of Representatives

The Hon. Mike Lee, Chairman
The Hon. Martin Heinrich,
Ranking Member
Energy & Nat. Resources Comm.
U.S. Senate

The Hon. James Comer, Chairman
The Hon. Gerald Connolly,
Ranking Member
Oversight & Gov't Reform Comm.
U.S. House of Representatives

The Hon. Jay Obernolte, Chair
The Hon. Ted Lieu, Co-Chair
Bipartisan Task Force on AI
U.S. House of Representatives

Dear Republican and Democratic Leaders:

As Congress works with the Administration to identify and cut wasteful expenditures, we respectfully request your oversight regarding almost a quarter of a billion dollars in federal grants issued by the Department of Energy (DOE).

Our members own, develop, construct, finance, and manage all types of income-producing properties in every U.S. market and abroad. We provide housing for our citizens, offices for our businesses, and classrooms for our students. Patients heal in our health care facilities and innovation happens in our laboratories. Our data centers are critical for AI technologies and crypto asset markets; our cell towers enable communication; and our warehouses support supply chains for storing and transporting goods. Our members own shopping centers where commerce happens, and hotels where we connect with family and friends. Our members' buildings touch virtually every aspect of life in America. Addendum 1 summarizes the massive economic benefits that real estate delivers for the economy.

Market Square West • 801 Pennsylvania Ave., NW • Suite 720 • Washington, DC 20004 • Phone: 202-639-8400 • Fax: 202-639-8442 • www.rer.org

Last year, DOE committed $240 million to 19 cities, municipalities, and states across the country to create and enforce local laws known as Building Performance Standards (BPS). DOE claimed the *Inflation Reduction Act* provided authority for these grants. BPS laws are like "EV mandates" for buildings. They impose fines and penalties on all types of properties if they fail to meet "targets" for greenhouse gas emissions, and unless they "electrify" by abandoning use of natural gas heaters, boilers, stoves, and other equipment. The Real Estate Roundtable has developed a comprehensive, peer reviewed policy guide explaining some of the flaws that render these climate-related laws unreasonable.

For example: State and local BPS laws – including those supported by federal taxpayer dollars – levy monetary penalties on buildings even if properties meet the federal government's ***own*** voluntary standards for high performance real estate.

Our members have collaborated with federal agencies for years to develop industry-driven, non-regulatory guidelines signaling the best performing U.S. real estate assets to domestic and global markets. Our public-private partnerships with DOE and the U.S. Environmental Protection Agency (EPA) serve multiple business and economic purposes. They incentivize buildings to reduce energy consumption and cut waste – thus saving families and businesses money on their utility bills. These programs encourage the real estate sector to do more with less so buildings minimize strain on the power grid – thereby conserving electricity our nation needs to lead the world in artificial intelligence, mine crypto assets, and generate a domestic manufacturing boom. Buildings branded with DOE's and EPA's imprimatur also attract investors seeking profitable assets that deliver high quality, modern spaces competing with the best real estate in the world. Our industry's public-private partnerships with the federal government are opportunities to unleash America's energy dominance and independence.

We ***support*** these collaborative EPA and DOE voluntary programs. However, we ***oppose*** DOE grants made by the last administration to encourage excessive and costly state and local "emissions targets" that regulate buildings. Issues warranting Congressional oversight include:

- Whether it is appropriate for a federal grant program to make an end run around federal limits on regulatory power. Should states and localities receive federal money to develop and enforce climate laws on buildings that no U.S. agency has authority from Congress to implement in the first place? In our view, the answer is "no."

- Whether it is appropriate for a federal grant program to support state and local climate laws imposing monetary fines on buildings, even if those assets meet federal criteria for top energy efficiency performers. What reasonable policy basis justifies spending federal money to create building performance laws that inflict penalties on properties lauded by the U.S. government itself? In our view, there is no reasonable basis.

- Whether the particular BPS grants at issue exceed the scope of legislative authority based on the plain text of the *Inflation Reduction Act*. In our view, these BPS grants fall outside statutory authority conferred by Congress.

At minimum, any state or locality that receives federal grants to develop onerous BPS laws should not levy monetary fines on buildings participating in federal partnership programs with the private sector. If these jurisdictions insist on imposing such fines, they should return federal taxpayer dollars.

The attachment and addenda provide more details explaining this issue. We welcome opportunities to meet with your Committees to explore avenues for investigation and hearings. Thank you for considering our request. Please contact Duane J. Desiderio, Senior Vice President and Counsel with The Real Estate Roundtable (www.rer.org), if you have further questions.

Sincerely,

Jeffrey D. DeBoer
President and Chief Executive Officer

Cc:
Members of:
U.S. House Committee on Appropriations
U.S. Senate Committee on Appropriations
U.S. House Committee on Energy & Commerce
U.S. Senate Committee on Energy & Natural Resources
U.S. House Committee on Oversight & Government Reform
U.S. House Bipartisan Task Force on Artificial Intelligence

The Real Estate Roundtable

The Case for Congressional Oversight Regarding Federal Grants for
State and Local Building Performance Standards (BPS)

- ***State and Local BPS Laws are "EV Mandates" – Directed at Buildings.***

We urge Congress's attention to federal grants to states and localities that undermine US-EPA and US-DOE guidelines through excessive climate regulatory laws known as Building Performance Standards (BPS). State and local BPS laws impose costly, burdensome, and unreasonable restrictions on properties to reach "net zero emissions." A key fault of these laws is they fail to account for choices and behaviors of the people who occupy and primarily consume power in buildings. While commercial property owners are responsible for central systems they do not set thermostats, turn off lights, or run appliances in leased spaces controlled by tenants. In practice, reaching a "net zero" BPS mandate requires renter households, small business tenants, and building owners to eventually stop using gas appliances and switch to equipment that runs on electricity instead.

BPS laws are thus like "EV mandates" for building owners and their occupants. A leading real estate data analytics firm described excessive state and local BPS mandates as approaching a European-like framework similar to the Paris Treaty's "net zero" emissions goals.[1] Of course, no law passed by Congress imposes a "net zero" standard or natural gas ban on private sector buildings. Some cities and states may go down this path. If they do, federal grants should not support their efforts.

- ***States and Localities Should Not Receive Federal Grants for BPS Laws That Penalize "High Performance Buildings" Meeting Federal Guidelines.***

Certain jurisdictions are using federal taxpayer money to create laws that levy fines on apartments, offices, stores, health care facilities, hotels, and other commercial properties – without any exemption or relief for a building that satisfies the federal government's own ambitious energy efficiency standards.

DOE announced its first round of federal BPS grant recipients on August 29, 2024, with a second round of applications from state and local governments closing on September 13, 2024.[2] Addendum 2 describes a sample of these state and local awards.

Congress did not intend these grants to be blank checks. A jurisdiction opting to take money ***from the federal government*** should not have unbridled discretion to develop climate-related regulations that punish buildings recognized ***by the federal government.*** Such real estate assets merit praise – not fines. Congressional review is warranted where, as here, U.S. grant dollars are being used to promote laws penalizing building cited by federal agencies as examples of industry leadership.

[1] See Green Street, "ESG & Property Insights: Your 'E' Sensitivity Training."

[2] See Daily Energy Insider, "DOE awards $240 million to municipalities to improve building codes, energy efficiency" (Aug. 29, 2024). DOE issued these grants under authority it claimed under the *Inflation Reduction Act* (*IRA*). The agency provided no criteria as to the terms or substance of state and local BPS laws that merited federal funding. See letter from The Real Estate Roundtable to former U.S. Energy Secretary Jennifer Granholm (Oct. 8, 2024). See also RTO Insider, "DOE Awards $240M for City, State Building Performance Standards" (August 28, 2024); Utility Dive, "State, local building energy codes get makeovers with over $240M from US DOE" (Aug. 28, 2024).

- ***The U.S. Real Estate Industry Strongly Supports Our Voluntary, Market-Driven Partnerships with EPA and DOE.***

The United States government has created the best system of voluntary guidelines in the world recognizing high performance, energy efficient buildings. Our industry is proud of the public-private partnerships we have forged over many years with non-partisan, non-regulatory programs like ENERGY STAR for buildings run by EPA and the Better Buildings Initiative run by DOE.

These programs are market-driven and science-based. They give our members standardized tools and data to monetize and forecast massive energy savings – which translate to utility bill savings for families and businesses. These EPA and DOE programs help reduce the strain on our power grids. They also provide a competitive edge for our industry to attract global capital from overseas investors seeking modern, profitable, and resilient real estate assets. ***We urge Congress's strong support and continued ample appropriations for these non-regulatory EPA and DOE industry partnership programs.***

At minimum, DOE should place a condition that no BPS law supported by a federal grant can impose monetary penalties on a building certified under EPA's ENERGY STAR program, or included in a company's real estate portfolio participating in DOE's Better Buildings Initiative. If a jurisdiction declines such a reasonable grant condition, it should return any money it already received and/or not receive any future disbursements.

- ***BPS Mandates Do Not Adequately Consider Grid Reliability – Or Whether They Will Even Prove Effective in Cutting Overall Emissions.***

BPS laws, and their hyper-focus on building electrification and emissions reduction, overlook their impact on the electric grid's ability to deliver reliable power to the community.

"Uncertainty abounds as to how much electricity demand will grow in the future and where it will come from. We are at the start of a new demand era, with no historical trend line to consult and a wide range of potential outcomes."[3] A recent report from the Bipartisan House Task Force on Artificial Intelligence concluded, "the growing demands of AI are creating challenges for the grid."[4] Proper planning is critical now to ensure expanded power supplies are available for AI innovation and adoption. "While new data centers take one to two years to construct, new power plants take five to ten years, and new power transmission lines take fifteen to twenty years."[5] Aside from AI, energy-intensive U.S. domestic manufacturing and continued consumer interest in electric vehicles will result in unprecedented electricity demand growth.[6]

BPS policy makers, however, would place even more strain on the power grid with fleets of electric buildings on every street corner. We request Congress to investigate BPS laws in an effort to galvanize states and localities to evaluate fully whether their electric grids have the basic capacity to achieve widespread building electrification. Any state or locality receiving a federal BPS grant should be compelled to assess how their laws impact the electric grid and report accordingly to Congress, DOE, and its citizens.

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[3] Wood Mackenzie, *Gridlock: the demand dilemma facing the US power industry* (Oct. 2024), at p. 3.
[4] 118th Congress, Bipartisan House Task Force Report on Artificial Intelligence (Dec. 2024) at p. 173.
[5] *Id.*
[6] Wood Mackenzie, *supra* note 3.

Furthermore, BPS jurisdictions largely neglect whether their laws singling out buildings will actually reduce emissions ***overall***. EPA data show that grid operators across the country rely predominantly on natural gas, coal, and other fossil fuels to provide electricity.[7] In most jurisdictions, grid-related emissions far exceed direct building emissions, and onerous BPS mandates on buildings will not result in climate benefits while emissions from electric plants only increase to handle insatiable demands for power. EPA evidence showing this fact is an afterthought for most state and local BPS lawmakers.

A 20-point policy guide developed by The Real Estate Roundtable ("RER") discusses these and other shortcomings inherent to many BPS laws, such as their potential to worsen the affordable housing crisis.[8] We urge Congress to investigate whether state and local building performance mandates – particularly those supported by federal grants – fairly and adequately address grid reliability, the fuel mix for electricity generation, housing affordability, and other policy matters addressed in RER's peer reviewed policy guide.

- ***DOE Exceeded its Statutory Authority in Issuing BPS Grants.***

The legality of DOE's grants is questionable. Any purported authority here derives from §§ 50131(a)(2) and (c) of the *Inflation Reduction Act.* (See statutory text at Addendum 3.) The statute gives DOE authority to issue state and local grants "for zero building energy ***code*** adoption" pertaining to "***new and renovated*** residential and commercial buildings." However, DOE did ***not*** disburse the $240 million in grants for ***codes***. The money went to ***BPS laws,*** beyond § 50131's scope.

In real estate circles, it is well-understood that building "codes" are ***not*** building "performance standards." "Codes" cover "new and renovated buildings," consistent with the statutory text at issue. "Codes" do not impose regulations on how ***existing*** buildings function or operate. That is where "performance standards" come in. BPS mandates apply to ***existing*** buildings – but the statutory authority only extends to "***new and renovated"*** construction. Insofar as the $240 million grants support "performance standards" for ***existing*** buildings, these awards exceed § 50131's bounds.

DOE itself recognizes the basic distinction between "codes" and "performance standards." So does the Institute for Market Transformation (IMT), the NGO that has "played a key role in every building performance standard in the U.S. to date." IMT itself received a $5.5 million federal grant to provide "tailored technical assistance" to 11 jurisdictions across the country to develop BPS laws.[9] Addendum 4 sets forth DOE and IMT sources explaining the difference between "codes" versus "BPS" laws.

As part of its oversight, we urge Congress to consider the legality of BPS grants in light of the *IRA*'s plain text in § 50131 and recent U.S. Supreme Court case law on principles of statutory interpretation.[10]

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[7] See EPA, Emissions & Generation Resource Integrated Database (eGRID) (Power Profiler tool shows all regions of the U.S. combust more fossil fuels than non-fossil fuels to generate electricity).
[8] The Real Estate Roundtable, *Lessons Learned to Shape Fair and Reasonable Building Performance Standards: 20-Point Policy Guide* (Oct.2024).
[9] IMT, press release, "Department of Energy Awards IMT $5.5 Million for Building Performance Standards Work" (Sept. 19, 2024). IMT states it is offering BPS assistance to States of California and Oregon; Berkeley, CA; Boston; Chicago; Denver; Kansas City, MO; Montgomery County, MD; New York City, San Francisco; St. Louis; and Washington, DC). A number of these jurisdictions received their own direct grants under *IRA* § 50131(a)(c) at issue. See Addendum 2.
[10] E.g., *West Virginia v. EPA* (597 U.S. 697 (2022) (agency must point to "clear congressional authorization" to support the power it claims); *Loper Bright Enterprises v. Raimondo* (603 U.S. 369) (2024) (no agency deference is due to its interpretation of ambiguous statutory language).

The Real Estate Roundtable

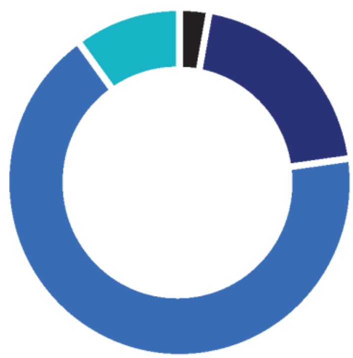
ADDENDUM 1

About The Real Estate Roundtable

www.rer.org

The Real Estate Roundtable brings together leaders of the nation's top publicly-held and privately-owned real estate ownership, development, lending, and management firms with the leaders of major national real estate trade associations to jointly address key national policy issues relating to real estate and the overall economy.

Who We Are



Asset Managers

3%

Financial Services

20%

58% Banks (Commercial & Investment)

16% Mortgage Bankers

26% Insurers

Owners

67%

55% Private

44% Public

46% Mixed

14% Office

12% Retail

12% Hotel

11% Housing

4% Industrial

2% Other

Real Estate Trade Organizations

10%

American Hotel & Lodging Association (AHLA)

American Resort Development Association (ARDA)

Association of Foreign Investors in Real Estate (AFIRE)

Building Owners and Managers Association Int'l. (BOMA)

CRE Finance Council (CREFC)

CREW Network (CREW)

International Council of Shopping Centers (ICSC)

Mortgage Bankers Association (MBA)

NAIOP, the Commercial Real Estate Development Association (NAIOP)

National Apartment Association (NAA)

National Association of Home Builders (NAHB)

National Association of Real Estate Investment Managers (NAREIM)

Nareit (NAREIT)

National Association of Realtors® (NAR)

National Multifamily Housing Council (NMHC)

Pension Real Estate Association (PREA)

Real Estate Executive Council (REEC)

Urban Land Institute (ULI)

Real Estate's Impact on the U.S. economy:
(*See* Commercial Real Estate by the Numbers: 2024)

- **$22.5 trillion:** Total value of America's commercial real estate
- **$2.5 trillion:** Real estate's contribution to U.S. GDP
- **14.1 million:** U.S. jobs directly supported by real estate
- **$600 billion:** Yearly property taxes paid by CRE owners to local governments
- **$900 billion:** Amount invested in U.S. real estate by pension funds, educational endowments, and charitable foundations

The Real Estate Roundtable

ADDENDUM 2

"Round 1" federal BPS grant recipients include the following cities and states. To our knowledge none of these jurisdictions commit to exempting buildings, deemed as "high performers" by the US-EPA or US-DOE, from monetary fines or penalties.

- **Chula Vista, CA:** Received a $10 million grant "to be provided over the next nine years" focused on "improving the performance of the city's 750 multifamily, commercial, and industrial buildings 20,000 square feet or larger."

- **Colorado:** Received a $20 million BPS grant from US-DOE to provide "technical assistance" to upgrade buildings in "low-income disadvantaged communities."

- **Denver, CO:** Received a $7.5 million grant from DOE "to implement its existing BPS and start working on future, more rigorous standards."

- **Evanston, IL:** Received a $10.7 million grant, "subject to negotiation with the U.S. Department of Energy, will support the adoption and implementation of building performance standards that will reduce emissions" and "require buildings to phase out onsite fossil fuel combustion."

- **Hawaii:** Received an $18.1 million grant to "develop and adopt a building performance standard with an objective of simultaneously reducing costs and making resources, jobs, and training available in disadvantaged communities."

- **Kansas City, MO:** Received a $9 million grant to develop a new BPS law that will "require buildings to meet specific energy and greenhouse gas emissions targets" and "elevate the performance of existing structures through ongoing upgrades and improvements."

- **Milwaukee, WI:** Received a $9 million grant "to develop a building performance standard informed by an existing data-driven buildings analysis program and engagement with local community stakeholders."

- **Lakewood, CO:** A suburb of Denver, received a $5 million BPS grant "to develop and implement a local standard in line with the state BPS."

- **Massachusetts:** Received a $19.9 million grant "to support implementation of building performance standards through direct technical support and capacity building among existing building trades programs in Justice40 communities and the creation of a Building Performance Exchange hub."

- **New York City:** Received a $19.9 million "federal funding infusion" to implement Local Law 97 (LL 97), requiring most NYC buildings to achieve "stricter limits" of 40% emissions reductions by 2030, with the ultimate goal to reach "net zero" emissions by 2050. On December 20, 2024, DOB published the final version of its latest package of rules to implement Local Law 97 that do not exempt buildings from fines if they meet US-EPA or US-DOE performance criteria.

- **Ohio cities of Cincinnati, Cleveland, Columbus and Dayton:** Received a joint $10 million grant to develop a BPS law and create a "High Performance Buildings Hub" to "support" building owners with meeting BPS targets.

- **Philadelphia, PA:** Received $19.8M "to develop a building performance standard to maximize emissions reductions from large buildings, while providing support programs that will ensure equitable outcomes with high compliance rates."

- **San Francisco and Berkeley, CA:** Received a joint $19.9 million grant "to electrify large commercial and multi-family buildings" and "implement equitable Building Performance Standards (BPS) aimed at modernizing buildings and reducing carbon emissions."

- **Seattle:** Received a $17.2 million BPS grant that will "span across nine years (2025-2033)" with a a focus on supporting buildings in overburdened communities and building an equitable climate workforce." DOE grant dollars will be used, among other things, to create a BPS "customer support hub" and consult with building owners on net zero GHG emissions "compliance pathways."

ADDENDUM 3

***Inflation Reduction Act*, §§ 50131 (a), (c) (see pp. 225-226 here).**

PART 3—BUILDING EFFICIENCY AND RESILIENCE

SEC. 50131. ASSISTANCE FOR LATEST AND ZERO BUILDING ENERGY CODE ADOPTION.

(a) APPROPRIATION.—In addition to amounts otherwise available, there is appropriated to the Secretary for fiscal year 2022, out of any money in the Treasury not otherwise appropriated—

….

(2) $670,000,000, to remain available through September 30, 2029, to carry out activities under part D of title III of the Energy Policy and Conservation Act (42 U.S.C. 6321 through 6326) in accordance with subsection (c).

(c) ZERO ENERGY CODE.—The Secretary shall use funds made available under subsection (a)(2) for grants to assist States, and units of local government that have authority to adopt building codes—

(1) **to adopt a building energy code** (or codes) for residential and commercial buildings that meets or exceeds the zero energy provisions in the 2021 International Energy Conservation Code or an equivalent stretch code; and

(2) to implement a plan for the jurisdiction to achieve full **compliance with any building energy code** adopted under paragraph (1) **in new and renovated residential and commercial buildings,** which plan shall include active training and enforcement programs and measurement of the rate of compliance each year.

ADDENDUM 4

The U.S. Department of Energy recognizes that a building energy "code" is not a building "performance standard":

> ***"Unlike building energy codes,*** which set minimum requirements for energy-efficient construction at the time of construction and major renovation, a Building Performance Standard (BPS) is designed to ensure buildings meet specific levels of performance over their lifetime. ***Given the different goals of codes and BPS,*** it is possible that buildings constructed and occupied within the years preceding, during, or immediately following the adoption of BPS may be ***compliant with the applicable energy code but unable to meet the BPS targets*** …."[11]

- DOE, Office of Energy Efficiency and Renewable Energy, *Energy Codes and Building Performance Standards* (2023) (emphasis supplied).

The Institute for Market Transformation (IMT) likewise recognizes that a building energy "code" is not a building "performance standard":

> "Leading jurisdictions are seeking to address climate and decarbonization goals on ***two policy fronts:*** energy codes and building performance standards. The combination seems like a perfect match, with ***one addressing new construction and one addressing the existing building stocks."***

- IMT, *The Intersection of Energy Codes and Building Performance Standards* (2022) (emphasis supplied).

[11] DOE, Office of Energy Efficiency and Renewable Energy, *Energy Codes and Building Performance Standards* (2023) (emphasis supplied).

NASEO

National Association of State Energy Officials

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March 4, 2025

The Honorable Bob Latta
Chairman, Subcommittee on Energy
House Energy and Commerce Committee
U.S. House of Representatives
Washington, DC 20515

The Honorable Kathy Castor
Ranking Member, Subcommittee on Energy
House Energy and Commerce Committee
U.S. House of Representatives
Washington, DC 20515

Dear Chairman Latta, Ranking Member Castor, and Members of the Subcommittee:

On behalf of the **National Association of State Energy Officials (NASEO)**, thank you for the opportunity to submit this letter for the record of the Subcommittee's hearing entitled, *"Scaling for Growth: Meeting the Demand for Reliable, Affordable Electricity."* NASEO represents the 56 governor-designated energy directors and their offices from every state and territory, and our members are committed to ensuring that every American community has access to **reliable, resilient, and affordable** energy.

State-Federal Coordination
NASEO commends the Subcommittee's leadership in exploring policies to modernize the nation's electric grid and meet rapidly growing demand. **Collaboration between federal agencies and State Energy Offices** is critical for ensuring effective solutions that secure affordable, reliable electricity while boosting **economic growth** and **job creation**. State Energy Offices, supported through the U.S. Department of Energy's (DOE) State Energy Program (SEP), bring on-the-ground expertise, program design, and policy leadership to bear on complex energy challenges. Their generally **non-regulatory** role, spanning all energy sources—petroleum, natural gas, and electricity—makes them well-positioned to forge partnerships with utilities, local governments, and private-sector stakeholders.

Meeting Rising Power Demand
States are taking decisive steps to ensure adequate and reliable **electricity supply** to meet the needs of growing industries such as data centers and manufacturing, as well as the accelerating electrification of transportation. **Load planning**, **infrastructure permitting**, and thoughtful integration of both **conventional** and **emerging** generation sources are indispensable to sustaining economic momentum. By leveraging SEP resources, states design and implement strategies that anticipate future consumption, reinforce critical infrastructure, and enhance grid and fuels resilience against weather events, cyber threats, and aging equipment failures.

Innovative Technologies and Partnerships

States are at the forefront of deploying next-generation solutions in **artificial intelligence**, advanced data management, and **clean energy** technologies that can improve system operations and reliability. To support these objectives, NASEO and a geographically diverse group of State Energy Offices launched the **Advanced Nuclear First Mover Initiative (Initiative)** on February 5, 2025. This effort has participation by the State Energy Offices of Indiana, Kentucky, Maryland, New York, Pennsylvania, Tennessee, Utah, Virginia, West Virginia, and Wyoming. By exploring new approaches to **reduce financial and technology risks**, **streamline federal permitting**, **define supply chain needs**, and **develop state-federal-private financing structures**, the Initiative seeks to ensure that **advanced nuclear** can provide **firm, clean power** to bolster reliability, affordability, and sustainability.

Governors from these states have voiced their strong support for this initiative and cited the importance of advanced nuclear technologies in meeting rising energy demand while spurring economic development. Ultimately, this Initiative strives to **reduce the cost** of delivering advanced nuclear technologies while **strengthening reliability** and maintaining affordability for households and businesses alike.

States across the country, especially in the west, have been accelerating their work to **promote geothermal energy**. The western governors on a bipartisan basis and their State Energy Offices are pushing to identify sites and reduce permitting problems. And DOE has identified geothermal energy potential in several southern states as well. We urge the Committee to look at ways to reduce federal permitting challenges at agencies in coordination with the House Committee on Natural Resources. Interconnection of these sites is critical and the regional transmission facilities can play a significant role in accelerating this resource. The State Energy Offices in the region are working together to coordinate with private developers and utilities to bring these resources to the grid.

Electric Transmission and Distribution Planning

NASEO is working closely with the individual states to accelerate electricity transmission and distribution planning and implementation through the expanded statutory authority under SEP. The State Energy Offices are supporting streamlined permitting, planning, site banking, coordination with the DOE Office of Electricity, work with the North American Electric Reliability Corporation (NERC), interaction with the Federal Energy Regulatory Commission (FERC), coordination with state utility commissions, electric utilities, economic development agencies, developers, residential and commercial energy users, and others to support a more robust transmission and distribution system. Holistic approaches are the hallmark of this initiative. Support from the Committee is essential as we move forward to create a responsive 21st century electric system. NASEO commends Chairman Latta and Representative Matsui for their leadership last Congress and introduction of the SECURE Grid Act, which would empower states to more fully assess threats to the transmission and distribution systems.

Role of State Energy Offices in Energy Security

Finally, **energy security** – electricity, natural gas, petroleum products – remains central to the mission of every State Energy Office. From preparing for and responding to natural and manmade disasters, to addressing evolving cyber threats, our members serve as key partners to federal agencies, utilities, fuel providers, and local governments. They coordinate energy emergency and resilience plans, conduct energy emergency exercises, provide critical response and recovery support during emergencies, and maintain DOE-recognized State Energy Security Plans—supported by **SEP cost-match** funding–to prepare for and mitigate energy supply disruptions. State Energy Offices' energy emergency planning and response actions cover all hazards and all fuels – electricity, natural gas, and petroleum products. When energy supply disruptions occur—resulting from hurricanes, cyberattacks on pipelines, wildfires, or severe winter storms—State Energy Offices help **minimize economic impacts**, protect consumers, and restore critical services quickly to save lives and livelihoods.

Recommendations
Considering these urgent challenges and opportunities, NASEO respectfully requests that the Subcommittee:

1. **Support Continued State-Federal Collaboration.** Robust funding for the State Energy Program–SEP–and other key federal initiatives will enable states to innovate, expand advanced technologies such as **advanced nuclear**, **grid-scale storage**, and **geothermal energy,** and enhance their emergency preparedness activities.
2. **Facilitate Infrastructure Permitting and Deployment.** Streamlining siting and approval processes for both **traditional** and **emerging** generation resources—along with necessary transmission investments—will be essential to delivering reliable, affordable electricity.
3. **Advance Modernization and Security.** Encourage policies that promote **grid resilience** and **cybersecurity**, expand systems capable of meeting higher demand, and support crucial R&D in **artificial intelligence** and **clean energy** solutions.

Conclusion
Thank you for convening this important hearing and for focusing on the strategies needed to scale our electricity system for growth. NASEO stands ready to work with you, DOE, and public-private stakeholders to ensure that **American families and businesses** have the **reliable, affordable, and clean** electricity they need today and in the future. If you have any questions or would like additional information, please contact me at 703-395-1076 or DTerry@NASEO.org.

Best regards,

David Terry, President, NASEO
National Association of State Energy Officials
1300 17th Street, North
Arlington, Virginia 22209

The Honorable Brett Guthrie
Chairman
House Energy and Commerce Committee
2125 Rayburn HOB
Washington, DC 20515

The Honorable Frank Pallone
Ranking Member
House Energy and Commerce Committee
2322A Rayburn HOB
Washington, DC 20515

The Honorable Robert Latta
Chairman
House Energy and Commerce subcommittee on Energy
2125 Rayburn HOB
Washington, DC 20515

The Honorable Kathy Castor
Ranking Member
House Energy and Commerce subcommittee on Energy
2322A Rayburn HOB
Washington, DC 20515

Dear Chairmen Guthrie and Latta and Ranking Members Pallone and Castor:

IHI Americas respectfully requests this letter be entered in the hearing record of the subcommittee on Energy's Wednesday, March 5, 2025, hearing titled "Scaling for Growth: Meeting the Demand for Reliable, Affordable Electricity."

IHI Americas is a wholly owned subsidiary of IHI Corporation which is a 170-year-old Japanese company. IHI is a heavy industry corporation that makes jet engines, ships, boilers, gas turbines, liquid natural gas (LNG) terminal equipment, nuclear energy components including both conventional and small modular reactors, and carbon solution technologies utilizing ammonia as clean fuel.

Demand for electricity is increasing year over year, and the International Energy Agency predicts that "US electricity demand to grow at an average annual rate of 2% over the 2025-2027 period, which is equivalent to adding the total electricity demand of California over the next three years.[1]" Most US coal power plants are operating at far less than their actual capacity. Adding ammonia as a secondary fuel will enable the plant to increase its electricity output without increasing its CO2 emissions.

In June 2024, IHI Corporation demonstrated a new technology that uses ammonia as a fuel and to co-fire it in existing 1,000MW coal powered electricity plant[2]. In this demonstration test, 20% substitution of fuel ammonia for operation of rated output of one-gigawatt has been

[1] https://www.iea.org/reports/electricity-2025/executive-summary

[2] https://www.powermag.com/global-first-jera-ihi-launch-testing-of-fuel-ammonia-at-coal-power-plant/

achieved successfully. This effort yielded favorable environmental outcomes. It is confirmed that carbon dioxide emissions at the unit fell around 20%, nitrogen oxide(NOx) emissions were equal to or less than when mono-firing coal before ammonia substitution, and sulfur oxide (SOx) emissions were down about 20%. We are now engaging with US coal plant operators to bring this technology here.

In our discussions with US coal power plant operators, several across the country have expressed the common challenge that they have is the ability to make investment decisions under market and regulatory uncertainty.

We believe including ammonia co-firing should be an eligible deduction under IRC § 45Q[3]. Presently, 45Q applies to only CO2 capture (CCS). However, the goal of this tax credit is to reduce CO2 emissions from power plants. We believe Congress should adopt a technology neutral definition that empowers utilities to choose not to produce CO2 in the first place instead of dictating that CO2 first needs to be produced, then captured and stored.

We thank you for your attention to our thoughts and would be happy to answer any questions that you or the subcommittee members may have.

Sincerely,

Naoki Kono

Naoki Kono

Vice President , Public Policy and Government Affairs Department,

IHI Americas Inc.

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[3] https://www.govinfo.gov/content/pkg/USCODE-2023-title26/pdf/USCODE-2023-title26-subtitleA-chap1-subchapA-partIV-subpartD-sec45Q.pdf

March 4th, 2025

The Honorable Brett Guthrie
Chairman
House Committee on Energy & Commerce

The Honorable Bob Latta
Chairman, Subcommittee on Energy
House Committee on Energy & Commerce

The Honorable Kathy Castor
Ranking Member, Subcommittee on Energy
House Committee on Energy & Commerce

Chairman Guthrie, Chairman Latta, & Ranking Member Castor:

On behalf of the Americans for Prosperity grassroots activists nationwide, especially those in Kentucky, Ohio and Florida, we applaud your efforts in scheduling the hearing "Scaling for Growth: Meeting the Demand for Reliable, Affordable Electricity." As you are aware, the need for reliable, affordable, and accessible electricity is a growing issue our country faces as new technologies come online. Today's generation, transmission, and distribution systems face increasing challenges; and the American people deserve to know that the systems powering their lives are both adequate and reliable for current and future grid demand.

Initially, we want to acknowledge the expertise that Representative Julie Fedorchak brings to this Subcommittee. With over a decade of experience in utility regulation, her service on the North Dakota Public Service Commission has provided an insight into the complexities of the electric power grid that few on Capitol Hill can match. Her leadership abilities were recognized by her peers at the National Association of Regulatory Utility Commissioners (NARUC) where she served as President, completing her term in November, 2024. AFP strongly encourages this Subcommittee to lean on Representative Fedorchak's knowledge as it crafts legislation that will impact ratepayers across the country.

For some time, our national policy has focused on the transition from fossil fuel based electric power generation to carbon-neutral and carbon-free generation. That transition has presented both opportunities for innovation and challenges to grid reliability. Environmental regulations, particularly from previous administrations' Environmental Protection Agency (EPA), have resulted in emissions and new source performance standards that have cost billions of dollars to achieve and have contributed to the skyrocketing utility bills across the nation.

Most recently, the Inflation Reduction Act contains numerous provisions that provide for production and investment tax credits that allow a utility to install intermittent power generation at the expense of grid reliability. Not only is grid reliability compromised, but firm baseload fossil fuel generated power has been taken offline at alarming speed.

Americans for Prosperity believes that an "all of the above" approach to energy generation is needed to achieve energy abundance. Instead of subsidizing one form of energy generation over another, we believe that all sources of generation should be allowed to thrive in the marketplace and operate on the grid. If our nation is going to meet the increasing demands that are placed on the grid, no generation source can be left behind.

Key players in the electricity space are the states. Under the Federal Power Act, states have certain responsibilities in the electricity space, specifically, the construction of generation and transmission assets. Across the country, there is an array of differing state priorities that can lead to disparate impacts on ratepayers, particularly if their electric service provider operates in multiple jurisdictions. And while efforts at the state level strive to mitigate negative impacts on ratepayers in each jurisdiction, the current complexity in the electricity space lends itself to unforeseen outcomes.

Across all 50 states, Americans for Prosperity is one of the largest grassroots organizations dedicated to free market principles, the competitive spirit, and innovation in the economy. To better add value to today's hearing, we offer the following insights from our educational efforts at the state level.

- AFP's state chapter in Wisconsin is educating ratepayers in that state on a proposed "Right of First Refusal" (ROFR) bill. In the electric transmission space, a ROFR gives an incumbent transmission provider rights of first refusal in building new transmission lines. This process eliminates competitive bidding on those transmission projects which in turn, can increase costs to ratepayers.

- AFP's state chapter in Arkansas has been working diligently to educate state legislators on the pitfalls of ROFR legislation. ROFR laws stand in direct contrast to the free-market principles that lead to accountability, reliability, and affordability for ratepayers, including those especially in Arkansas.

- AFP's state chapter in Arkansas has also been educating state legislators on the concept of "Only Pay for What You Get." This would require the utility regulatory commission in the state to only allow a utility to recover costs and expenses from ratepayers that contribute to system reliability.

- AFP's state chapter in Illinois has also worked with state legislators to urge opposition to ROFR laws that are anti-competitive and forcibly compel ratepayers to cover the costs of these projects without deference to the final cost. Competition is essential in all construction, and particularly so with respect to new transmission lines, as many of the materials needed to build these systems have increased drastically in cost.

- AFP's state chapter in Montana has worked to educate state legislators on legislation that would repeal ROFR. Recently, the Montana Senate passed a bill that would repeal

ROFR for public utilities that are regulated by the Montana Public Service Commission.

These are just some of the lessons learned by AFP's state chapters advocating and educating on behalf AFP grassroots activists across the country.

Due to this Committee's role in the House with respect to its jurisdiction over the Federal Energy Regulatory Commission (FERC), the Nuclear Regulatory Commission (NRC), and the U.S. Department of Energy (DOE), we encourage Members to be cognizant of federal actions that attempt to thwart competition, compromise grid reliability, and result in increased costs to ratepayers in the electricity space.

We look forward to the legislative developments following this hearing and appreciate the opportunity to comment on this important issue.

Respectfully Submitted,

Brent W. Gardner

Brent Gardner
Chief Government Affairs Officer
Americans for Prosperity

March 4, 2025

The Honorable Bob Latta
Chairman, Subcommittee on Energy
House Committee on Energy and Commerce
U.S. House of Representatives
Washington, DC 20515

Re: Hearing on “Scaling for Growth: Meeting the Demand for Reliable, Affordable Electricity”

Dear Chairman Latta and Members of the Subcommittee,

On behalf of Stop MPRP, Inc., I appreciate the opportunity to submit this letter for the record in advance of the upcoming hearing on "Scaling for Growth: Meeting the Demand for Reliable, Affordable Electricity." Stop MPRP, Inc. is a non-partisan grassroots organization dedicated to opposing the Maryland Piedmont Reliability Project (MPRP), a misguided and unnecessary transmission project that threatens to devastate farmland, forests, and rural communities while failing to provide meaningful solutions for energy reliability and affordability.

The MPRP represents an outdated and destructive approach to meeting projected electricity demand. This project would cut through Maryland’s historic and agricultural landscapes, displacing farmers, devaluing properties, and destroying vital natural resources. Yet, this disruption is based on speculative demand forecasting that fails to account for modern grid optimization and demand-side management solutions.

The notion that new transmission corridors must be built across private land is a false premise. As research increasingly demonstrates, the United States has the capacity to meet growing electricity demand through a combination of strategic upgrades to existing transmission infrastructure and policies that require data centers—the primary driver of recent demand surges—to co-locate their own generation. Studies, including recent testimony before this Subcommittee, have shown that optimizing existing grid capacity, implementing demand flexibility measures, and siting new transmission along existing corridors such as highways and railways can eliminate the need for greenfield projects like MPRP.

We urge Congress to advance policies that prioritize:

- Upgrading and optimizing existing transmission infrastructure before approving any new greenfield projects, ensuring that all feasible alternatives are exhausted before land is seized for transmission expansion.
- Requiring data centers and other large energy consumers to co-locate generation rather than burdening ratepayers and rural communities with unnecessary new infrastructure.
- Enhancing demand management programs to reduce peak electricity loads, leveraging advancements in load flexibility and distributed energy solutions to alleviate grid stress.
- Reforming transmission planning to protect rural communities and agricultural land by directing infrastructure siting along existing rights-of-way rather than taking privately owned land.

The American energy future should not come at the expense of landowners, farmers, and communities that have stewarded this land for generations. Instead, we must pursue forward-thinking solutions that modernize our energy system while preserving property rights, protecting natural resources, and ensuring affordable electricity for all.

We respectfully request that the Subcommittee consider these concerns as part of your ongoing efforts to shape a reliable and equitable energy policy. Thank you for your leadership on this issue, and we welcome the opportunity to further engage with you on policies that align energy growth with responsible land stewardship.

Respectfully submitted,

Joanne Frederick
President
Stop MPRP, Inc.
joanne.frederick@stopmprp.org
443.789.1382

BRATTLE ECONOMIC ANALYSIS OF CLEAN ENERGY TAX CREDITS - PREPARED FOR CONSERVAMERICA

A Wide Array of Resources is Needed to Meet Growing U.S. Energy Demand

Prepared By
Sam Newell
Wonjun Chang
Paige Vincent

February 2025

Brattle

Disclaimer, Approach, and Qualifiers

DISCLAIMER

The following analysis contains forward-looking information and assumptions with respect to conditions which may exist or events which may occur in the future. The analysis is based on methodologies that simplify and may not always accurately represent the relationship between assumptions and outcomes. Except for statements of historical fact, the analysis cannot and does not provide assurances that the assumptions and methodologies used will prove to be correct or that the forecasts will match actual results of operations.

The analysis and assumptions used herein are also dependent upon future events that are not within our control or the control of any other person, and do not account for numerous market and regulatory uncertainties. Actual future results may differ, perhaps materially, from those indicated. The Brattle Group does not make, nor intend to make any representation with respect to the likelihood of any future outcome, cannot, and does not, accept liability for losses suffered, whether direct or consequential, arising out of any reliance on this analysis. The analysis was prepared by The Brattle Group experts Sam Newell and Wonjun Chang and reflects their analyses and opinions and does not necessarily reflect those of The Brattle Group's clients or other consultants.

APPROACH

Analyze the economic impacts of potential full removal of Clean Electricity Production Tax Credit (PTC) from §45Y and Investment Tax Credits (ITC) from §45E, affecting all new solar, wind, and storage coming online after 2025, all else equal.

Electricity demand is forecasted by compiling regional and utility forecasts from 2024.

Electricity supply and costs are modeled using a standard electric sector "capacity expansion" model.

- A Brattle proprietary best-in-class model, gridSIM
- Calibrated to today's fleet/prices/plans
- Simulates the future with least-cost investment and plant operation to meet currently-forecasted demand, given resource options and their costs with or without clean energy credits
- Accounts for transmission constraints, limited buildout by technology and geography accounting for land use, supply chain, and transmission interconnection pace
- Assumes states w/ clean energy mandates abide by them, but not EPA GHG rules under CAA §111

The broader effects on the economy (GDP, jobs) are modeled using a standard macroeconomic model.

- A Brattle proprietary model, BEYOND
- High-level representation of all sectors and regions: how they interact and change given electric sector impacts
- Uses standard inputs from open-source government data

QUALIFIERS

Focuses on most prevalent supply resources for meeting demand, understating the role increased energy efficiency and demand response can play; also does not quantify effects on less prevalent/ immediate recipients of credits, such as geothermal, mechanical storage, and new nuclear

Modeling optimistically assumes all new demand still enters even at higher electricity cost absent electricity credits, although the discussion addresses the possibility of not meeting all of that growth

Does not account for clean air benefits of clean energy credits

Does not account for technology development benefits furthered by development incentives for wind, solar, and storage that are less mature and still improving significantly in cost and performance

This is a "gross" economic analysis that does not account for economic benefits of alternative uses of tax dollars, deficit reduction, or taxpayer savings if clean energy credits were removed

Specific benefits are uncertain due to uncertainties in market and system conditions - such as demand growth, gas prices, resource costs, the pace of generation interconnection, and supply chain limits; results should be considered indicative

Executive Summary

Annual peak electricity demand in the U.S. is expected to increase 30% over the next decade, and a wide variety of resources is needed to support that and the associated economic growth; renewables and storage are ready now

A portfolio of all forms of energy resources can meet demand reliably and most cost effectively, but not all are available today

- Solar and wind are ready now at lowest cost
- Battery storage is ready now and provides capacity and quick-start capabilities
- Natural gas provides flexible backup, but with fewer MW currently in development and ~4-5 year development cycle
- Existing nuclear provides baseload; advanced nuclear will take more than a decade to commercialize widely
- Coal is less economic and declining

Source: Brattle's BEYOND model of the US economy, given outputs from gridSIM.
Notes: This analysis does not account for economic effects of alternative uses of tax dollars, deficit reduction, or taxpayer savings in the event that clean energy credits are removed. GDP and consumption values are expressed in $2024 dollars.

Elimination of clean energy credits would raise customer rates, reduce economic growth and eliminate jobs

- Average annual residential bill would increase
- GDP and jobs would decrease because of higher electricity rates and less construction, mostly in rural areas, leading to a total market impact of $820 B

Eliminating or altering clean energy credits would dramatically reduce investment in low-cost solar and wind generation, hurting economic growth

- Solar and wind investment through 2035 would be 50% lower, along with some decrease in storage
- Limited additional gas-fired generation is available until early 2030s, creating potential for a shortfall of supply to meet power need

Economic growth would be limited

American Demand for Power is Growing

Realizing economic growth will depend on how quickly new electric generation capacity can be added

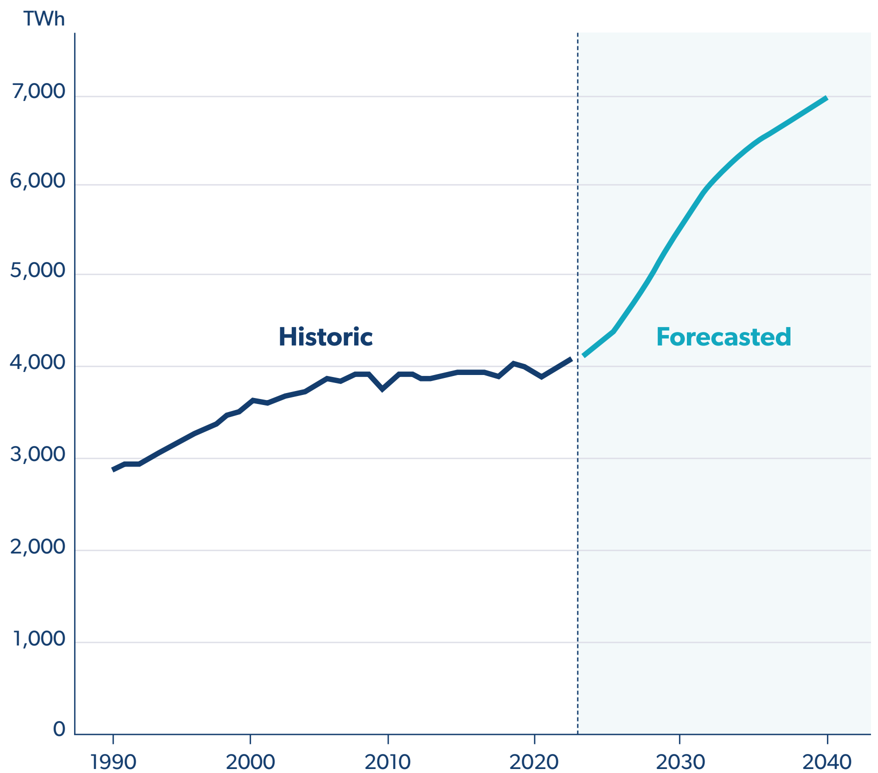
Electricity demand is surging to support an economic boom

- Data centers for AI
- Manufacturing reshoring
- Electrification of industry and other uses
- Growing oil and gas extraction

Serving this growth requires a lot more supply

- Peak demand growth rates exceed 5x that of the past decade
- By 2030, the U.S. will need to serve 20% higher annual peak or 150 GW
- By 2035, the peak will grow by 30%

By 2035, the U.S. will need 50% more annual electric energy production than today



Sources: a compilation of 2024 RTO and utility load forecasts for their own territories

All Supply Sources Are Needed to Meet Growing Demand Effectively

A wide array of resources is needed to provide enough power reliably and cost effectively

Nearly 2,000 GW of wind, solar, and storage projects in transmission interconnection queues

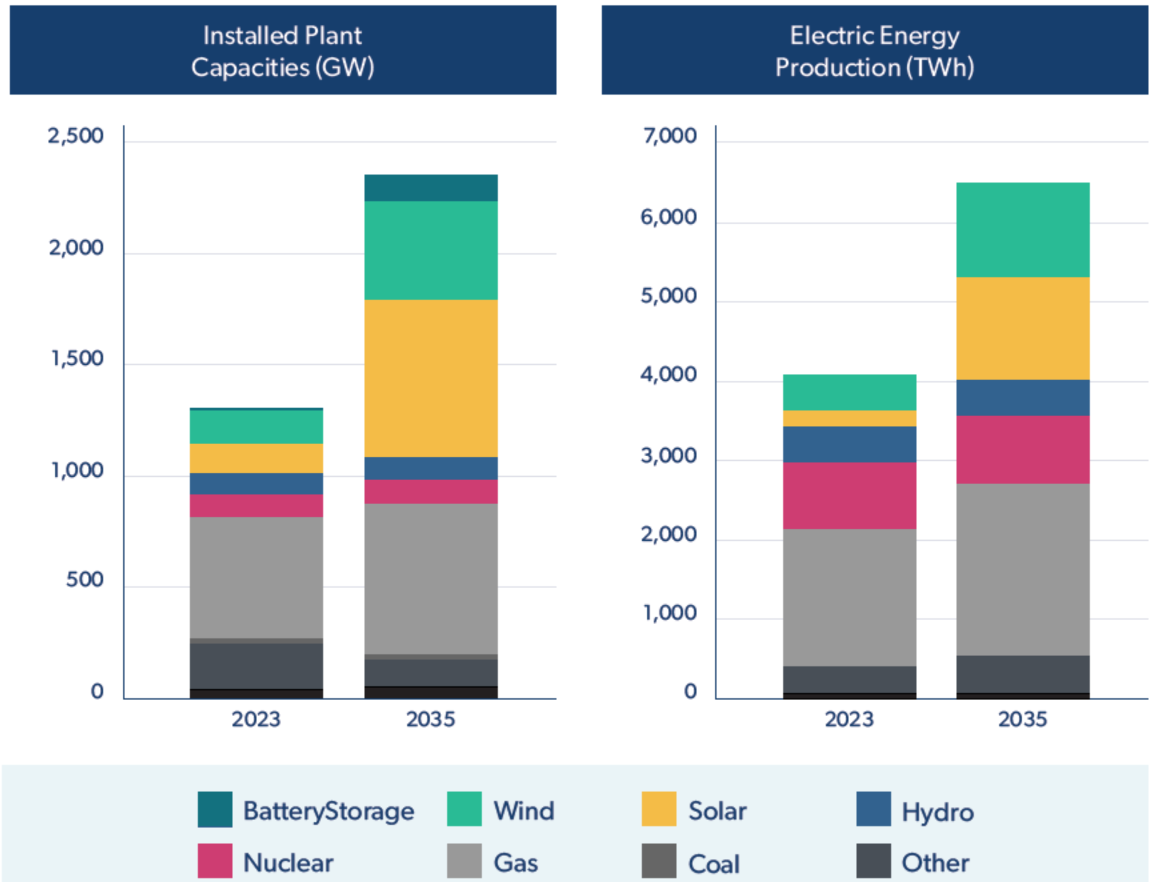
- Not all will be built, but a lot can be
- Even though these are intermittent or energy-limited, they produce a lot of low-cost energy and help meet demand growth

Much less gas fired generation is under development due to years of slow demand and limited turbine supply

- It will take years for the supply chain to develop and years for plants to be permitted, built and operational

Current and Future Energy and Capacity

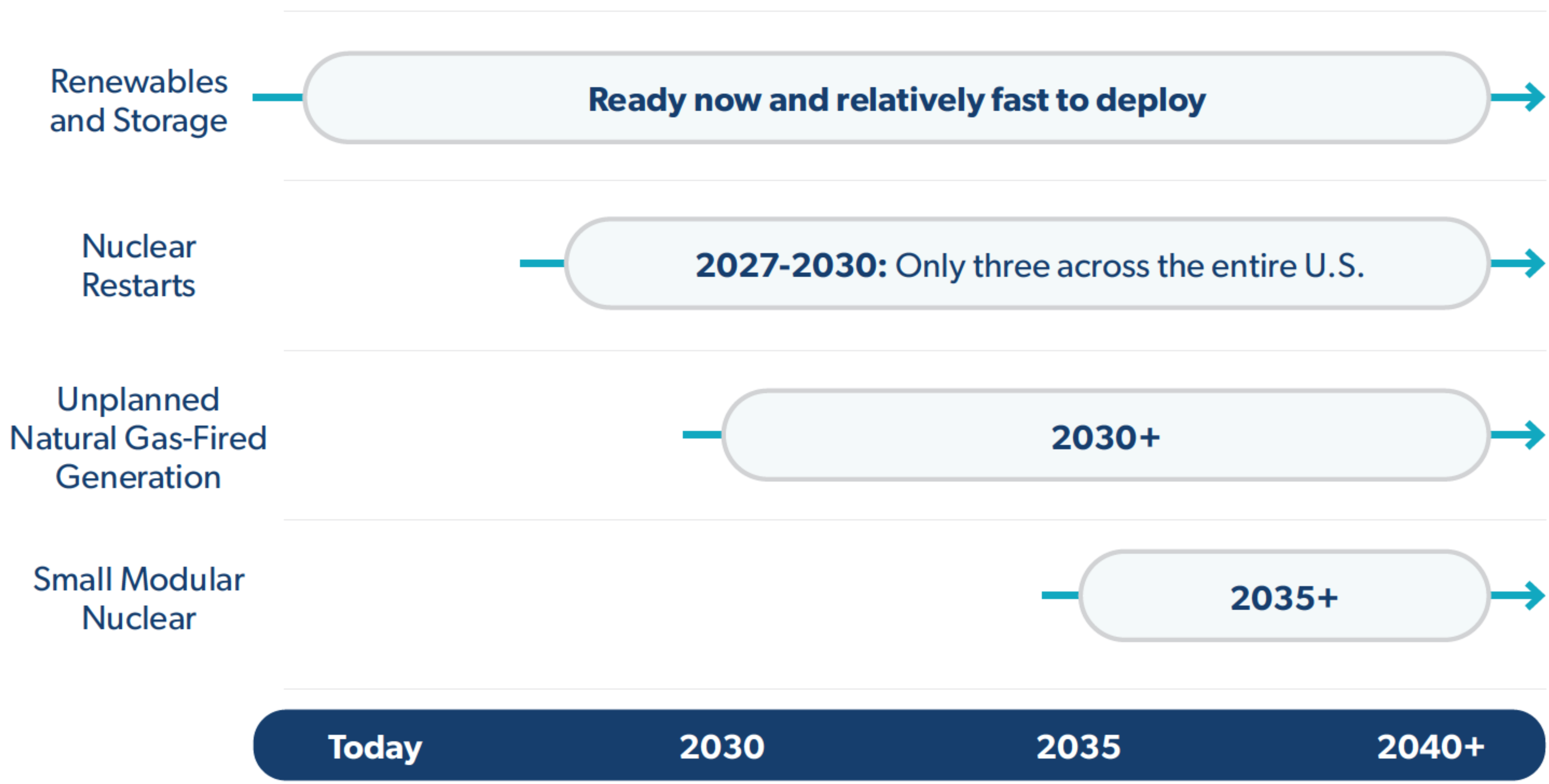
with current law and projected market conditions



Source: Brattle simulations of U.S. electricity investment and operations using gridSIM model, populated from EIA and other data sources

Solar, Wind and Storage Projects Are Already in Development and Can Meet Demand Now – Other Resources Are Available in Later Years

Expected Deployment Timelines by Generation Type

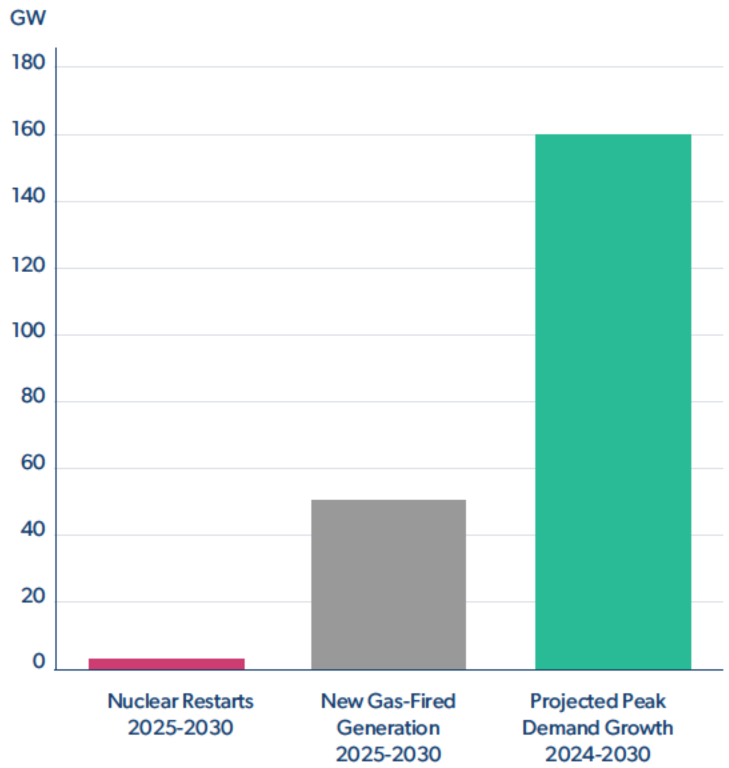


Note: all new supply has been facing multi year interconnection studies and network upgrades. Wind, solar, and storage projects are ahead of many other resources in that process.

Because of a Number of Factors, Gas and Nuclear Alone Cannot Meet Projected Demand Growth in the Near Term

- Long lead time for gas turbines
- Prolonged development and construction timelines
- Increasing price of gas turbines
- Transmission queues and delays
- Very long lead time for new nuclear

New-Build Gas-Fired Generation and Nuclear Restarts Likely Insufficient to Meet Projected Peak Demand



Source and notes: Rough estimate of max gas fired additions derived from statements from turbine manufacturers; does not include uprates to existing plants; Projected peak demand growth calculated from compilation of RTO and utility forecasts; does not account for the need to replace retirements.

Loss of Clean Energy Credits Would Dramatically Reduce Investment in American Energy Infrastructure

Solar and wind development would diminish markedly

- 50% less solar and wind would be built by 2035
- Reduces supply of low-cost energy and the main generation in development that is available now to meet growing power demand

New unplanned gas generation not built until roughly 2030+

Overall, capital investment would decrease, power prices would rise and consumers would be impacted

- $520 billion[1] less solar and wind investment through 2035 absent clean energy credits
- Power demand customers would still need generation, but without credits, they would pay higher prices
- As a result, the average American's electric bill would increase
- Risk of limiting growth of industry that demands much electricity

Estimated Impacts on New Investment in New Plants (GW)

	2026-30	2031-35	Total
Solar			
With Tax Credits	145	405	550
Without	121	121	242
Impact	-23	-284	-308
Wind			
With Tax Credits	181	73	254
Without	88	29	116
Impact	-93	-44	-137
Storage			
With Tax Credits	71	35	106
Without	83	17	100
Impact	12	-18	-6
Gas			
With Tax Credits	56	81	137
Without	56	124	180
Impact	0	43	43

1. Values are cumulative nominal undiscounted dollars.

Electricity Costs Would Increase for All American Consumers

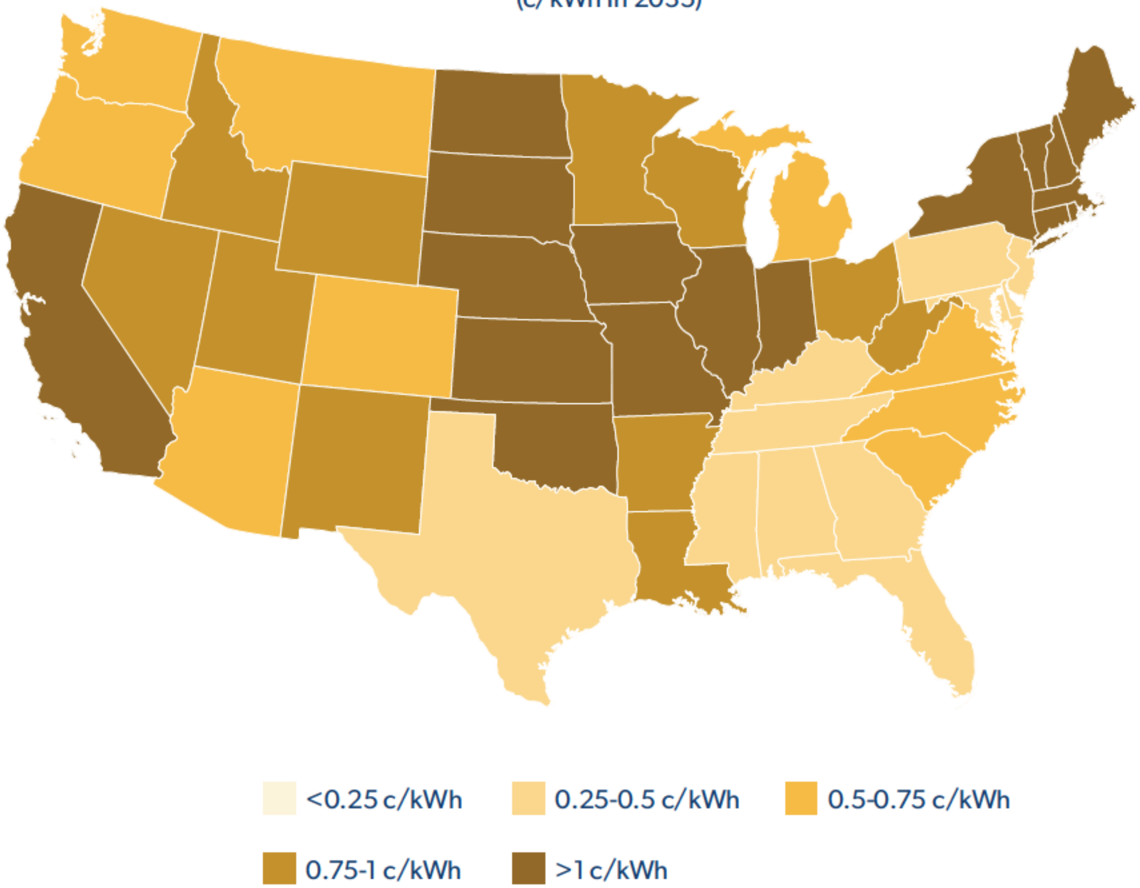
By 2035 loss of tax credits would increase going-forward generation system costs by 14% and be passed on to all American consumers

Residential electric bills would increase by an average of $83 per year, and as much as $152 per year in seven states[1].

Much like other energy costs, these rate impacts will place a heavier burden on lower and middle-income households

Year	Customer Costs (all classes)	Average Rates
2030	↑ **$26** Billion/Year	**+0.5** c/kWh
2035	↑ **$51** Billion/Year	**+0.8** c/kWh

Customer Electricity Cost Increases if Remove Clean Energy Credits
(c/kWh in 2035)



Source: Brattle's gridSIM simulations

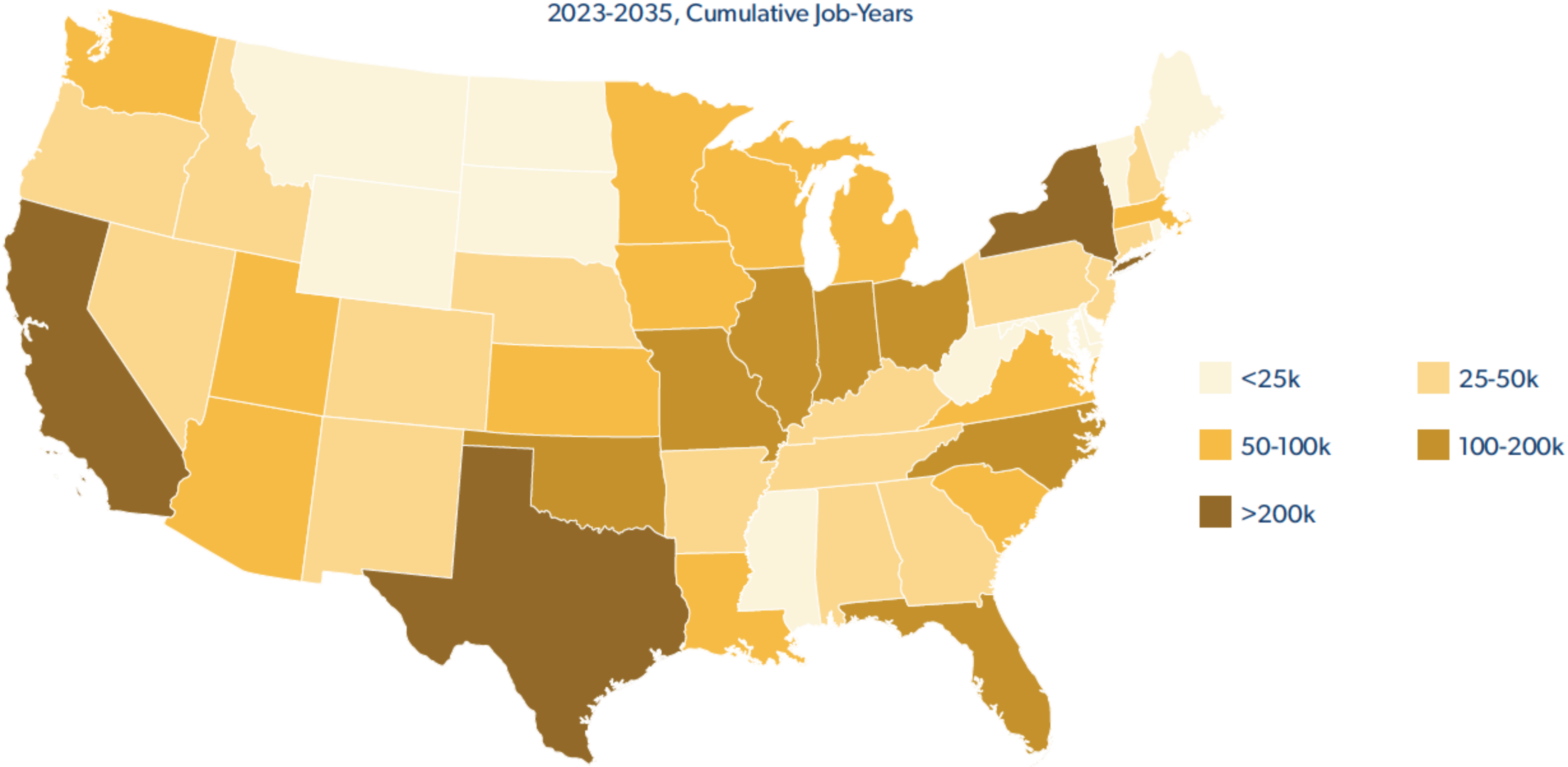
1. The seven states with the potential increase of up to $152 per year are North Dakota, South Dakota, Nebraska, Kansas, Oklahoma, Iowa, and Missouri due to their high wind capacity.

…And Eliminate Jobs Across the Country

3.8 million jobs-years lost cumulatively throughout the economy through 2035 as employers spend more on electricity, capital investment declines and higher electricity rates impact consumer spending in other sectors; or worse if tightened electricity supply limits growth of industry that depends on electricity supply expansion

Employment Impacts from Loss of Clean Energy Credits

2023-2035, Cumulative Job-Years



Source: Brattle's BEYOND model of the US economy, given outputs from gridSIM.
Notes: This analysis does not account for economic effects of alternative uses of tax dollars, deficit reduction, or taxpayer savings in the event that clean energy credits are removed.

…And Depress U.S. Economic Growth

Higher electric rates and the loss of solar/wind projects would affect the broader economy

Cumulatively from 2025 through 2035, under the optimistic assumption that all forecast demand growth will still be met, estimated economic impacts are:

Direct spending in the power sector: -$250 billion

- Almost 450 GW less renewables would be built, mostly in rural communities

GDP: -$510 billion

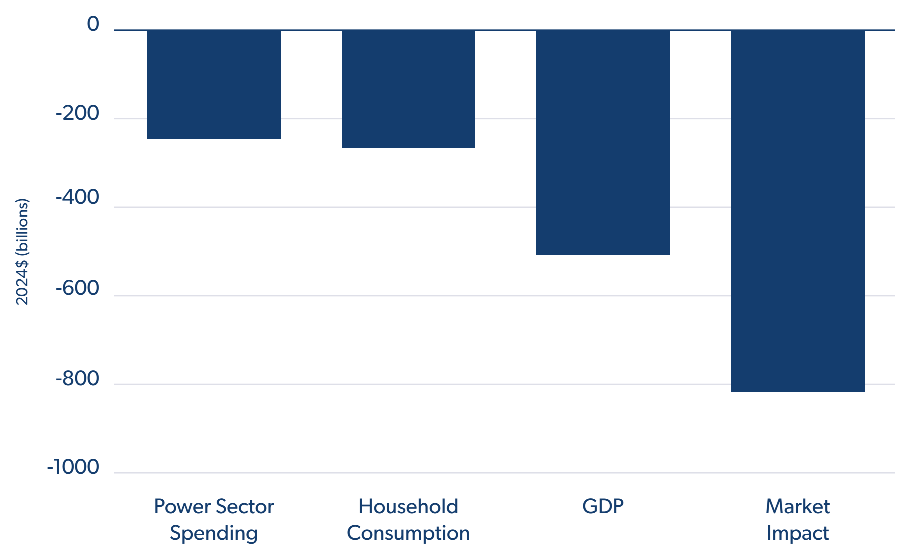
- Production would decrease due to less construction, higher electricity bills crowding out spending on other goods and wages, and less tax revenue
- Impacts would be felt throughout the economy

Household consumption: -$270 billion

- Higher household electricity bills, reduces spending on other goods
- Economic contraction (described above) results in lower household income

Economic Impacts of Removing Clean Energy Credits

2025-2035, Cumulative Billions in 2024 dollars



Total market impact: -$820 billion

- This is the change in all goods and services transacted throughout all value chains, including inputs and intermediates, not just final products

Source: Brattle's BEYOND model of the US economy, given outputs from gridSIM.
Notes: This analysis does not account for economic effects of alternative uses of tax dollars, deficit reduction, or taxpayer savings in the event that clean energy credits are removed.
GDP and consumption values are expressed in $2024 dollars.

Brattle

The Power of Economics™

Electricity Price Impacts of Technology-Neutral Tax Incentives With Incremental Electricity Demand from Data Centers

Prepared for Clean Energy Buyers Association (CEBA)

February 10, 2025

Sugandha Tuladhar, PhD
Julie M. Carey
Scott Bloomberg
Bharat Ramkrishnan
Julie Chen

ECONOMICS. EXPERTS. EXPERIENCE.

CONFIDENTIALITY

Our clients' industries are extremely competitive, and the maintenance of confidentiality with respect to our clients' plans and data is critical. NERA rigorously applies internal confidentiality practices to protect the confidentiality of all client information.

Similarly, our industry is very competitive. We view our approaches and insights as proprietary and therefore look to our clients to protect our interests in our proposals, presentations, methodologies, and analytical techniques. Under no circumstances should this material be shared with any third party without the prior written consent of NERA.

Introduction

- NERA Economic Consulting (NERA) was engaged by the Clean Buyers Energy Association (CEBA) to examine the impacts of technology-neutral tax incentives on delivered electricity prices to residential and other ratepayers. The technology-neutral tax incentives analyzed in this study include the §45Y production tax credit (PTC) or the §48E investment tax credit (ITC) to incentivize clean energy investments across various generating technologies. The PTC and ITC incentives analyzed include the bonus credits for the prevailing wage and apprenticeship requirements but do not include the bonus credits that relate to domestic content requirements, or for projects located in energy communities.
- To evaluate the impacts of the technology-neutral tax incentives, NERA has used our N_{ew}ERA electricity sector model and electricity rate model.
- The delivered electricity price impacts are estimated are for the lower 48 states under two electricity market outlooks: (i) An electricity market outlook with incremental electricity demand from growth in data centers and technology-neutral tax incentives; and (ii) An electricity market outlook with incremental electricity demand from growth in data centers in the absence of technology-neutral tax incentives.
- The following slides detail the electricity market modeling approach, scenarios that were evaluated, the key inputs to those scenarios, key results on delivered electricity prices and additional information about the N_{ew}ERA model. It is our understanding that these results will be used by CEBA to inform key stakeholder discussions on the technology-neutral tax incentives.

Summary of Key Results and Insights

The technology-neutral tax incentives has the effect of reducing delivered electricity prices to the ratepayers.

- U.S. residential, commercial and industrial (C&I)*, and all-sector average delivered electricity prices are projected to be higher by 6.7% (1.1 ¢/kWh)** and 7.3% (1.3 ¢/kWh), 9.7% (1.1 ¢/kWh) and 10.6% (1.3 ¢/kWh) , and 8.4% (1.1 ¢/kWh) and 9.2% (1.3 ¢/kWh) in 2026 and 2029, respectively, in the absence of the technology-neutral tax incentives.
- The increase in state-level residential electricity prices in the absence of the technology-neutral tax incentives range from 0.3% (0.08 ¢/kWh) to 21.3% (2.6 ¢/kWh) in 2026 and 0.9% (0.25 ¢/kWh) to 21.1% (2.7 ¢/kWh) in 2029.
- The increase in C&I electricity prices in the absence of the technology-neutral tax incentives range from 0.5% (0.08 ¢/kWh) to 31% (2.6 ¢/kWh) in 2026 and 1.4% (0.25 ¢/kWh) to 30.6% (2.7 ¢/kWh) in 2029 without the technology-neutral tax incentives.
- The states with highest price impacts in 2026 are WY, NM, IL, DC, WA, NC, MO, KS, SC, TN. DE, MD, AZ, MN and NE.***
- The states with highest price impacts in 2029 are WY, IL, NM, NC, TN, MD, NJ, DE, MO, SC, AZ, MN, WA, AR and NE.****

** C&I average delivered electricity prices are calculated as the weighted average of delivered prices to the commercial and industrial sectors weighted by their respective electricity sales.*
*** The prices are denominated in nominal dollars, unless otherwise noted*
**** These represent the top fifteen states that experience the largest % change in all-sector delivered electricity prices in 2026.*
***** These represent the top fifteen states that experience the largest % change in all-sector delivered electricity prices in 2029.*

Summary of Key Results and Insights

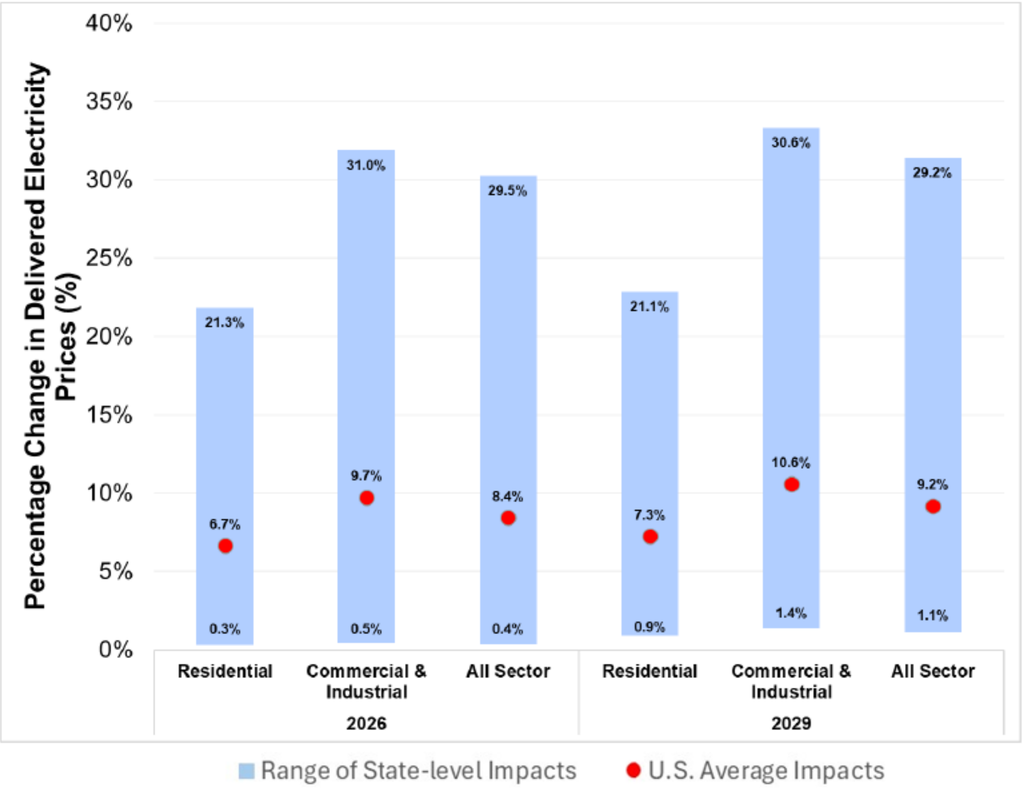
The technology-neutral tax incentives has the effect of reducing delivered electricity prices to the ratepayers.

- Cumulative new capacity additions of new generation capacity incentivized by the technology-neutral tax credits are projected to be lower by 167 GW; while 23 GW of new natural gas capacity additions are projected by 2029 in the absence of the technology-neutral tax incentives.
- The lack of technology-neutral tax incentives has the effect of increasing the electricity prices in both cost-of-service and competitive regions as electricity demand must be met by relatively more expensive generating technologies.
- The electricity price impacts for a state depend upon many factors, including availability of deployment of low-cost generating technologies, substitution between new generation capacity incentivized by the technology-neutral tax credits and fossil fuel-based generation, and electricity market structure for that state.
- The study's electricity price impacts are based on conservative assumptions of a moderate electricity load growth trajectory and moderate availability of technology-neutral tax incentives.

Summary of Projected Increase in Delivered Electricity Prices

Delivered electricity prices are projected to increase across all states and ratepayer classes if the technology-neutral tax incentives are not available.

- Average U.S. price impacts
  - The price impacts for the U.S. average residential electricity prices are 6.7% (1.1 ¢/kWh) in 2026 and 7.3% (1.3 ¢/kWh), in 2029
  - The price impacts for the U.S. average C&I electricity prices are 9.7% (1.1 ¢/kWh) in 2026 and 10.6% (1.3 ¢/kWh) in 2029
  - The price impacts for the U.S. average all-sector electricity prices are 8.4% (1.1 ¢/kWh) in 2026 and 9.2% (1.3 ¢/kWh) in 2029
- Range of price impacts across states
  - The price impacts for residential electricity prices range from 0.3% (0.08 ¢/kWh) to 21.3% (2.6 ¢/kWh) in 2026 and 0.9% (0.25 ¢/kWh) to 21.1% (2.7 ¢/kWh) in 2029
  - The price impacts for C&I electricity prices range from 0.5% (0.08 ¢/kWh) to 31.0% (2.6 ¢/kWh) in 2026 and 1.4% (0.25 ¢/kWh) to 30.6% (2.7 ¢/kWh) in 2029
  - The price impacts for the all-sector electricity prices range from 0.4% (0.08 ¢/kWh) to 29.5% (2.6 ¢/kWh) in 2026 and 1.1% (0.25 ¢/kWh) to 29.2% (2.7 ¢/kWh) in 2029



Study Limitations and Caveats

The study scenarios are not intended to model any specific regulation and incorporate technology-neutral tax incentives. The study provides conservative electricity price impacts that are based on a moderate electricity load growth trajectory and moderate availability of technology-neutral tax incentives.

- **Fixed Baseline Demand:** The study assumes the same electricity demand with and without the technology-neutral tax incentives outlooks. Future demand increases from data centers are uncertain and influenced by various factors.
- **Fixed Fuel Prices:** The study assumes fixed fuel prices, along with incremental demand from data center growth, which is based on moderate annual load growth of 5% from an expert assessment commissioned by EPRI.
- **Transmission Capacity:** The study does not model endogenous transmission line expansions.
- **Tax Incentives:** The study considers the §45Y production tax credit (PTC) and the §48E investment tax credit (ITC) to be technology-neutral, without additional credits applied for domestic content or facilities location in energy communities.
- **Economic Feedback:** The study does not model economic feedback on the electricity market or analyze the effects of the funding sources for the tax incentives.
- **Policy Modeling:** The scenarios presented are not designed to model specific policies, and the resulting electricity price impacts may vary based on different model inputs and assumptions.

1 Overview of the Modeling Approach

NERA's Delivered Electricity Price Estimation Approach

A detailed electricity dispatch model and a state-level rate model is used.

- NERA employed its N_{ew}ERA electricity sector model along with a state-level rate model to evaluate the electricity price impacts
- The inputs for the N_{ew}ERA model included regional demand, unit level characteristics (such as technology costs, fuel prices) which were drawn from EIA's AEO 2023 publication.
- The incremental demand from deployment of data centers were based on the 2024 EPRI study.[1]
- The technology-neutral tax incentives are based on EIA's modelling assumptions and applied to the capital and the operating costs of qualifying generating units.
- The model projects least-cost dispatch decisions for the various generating units, regional fuel, electricity, capacity and permit prices.
- The electricity system outputs from the N_{ew}ERA electricity model serve as inputs to NERA's state-level rate model.
- The state-level rate model is a bottom-up model that produces delivered electricity price by rate-payer class (residential, commercial, industrial) based on electricity market type in the state (competitive vs. cost-of-service).

[1] EPRI, Powering Intelligence: Analyzing Artificial Intelligence and Data Center Energy Consumption, May 28, 2024, available at https://www.epri.com/research/products/3002028905

N_{ew}ERA Electricity Sector Model

The NewERA model is a bottom-up dispatch and capacity expansion model.

- The N_{ew}ERA model is a bottom-up dispatch and capacity expansion model with unit-level information on generating units in 63 U.S. regions (and 11 Canadian regions) with regional demand and capacity requirement representation.
- The model produces a least-cost projection of market activity, satisfying demand and all other constraints (emission limits, transmission limits, fuel availability and regulations) over the model time horizon, projecting unit-level generation and investment decisions, regional fuel and electricity prices.
- Electricity generators are represented at the unit-level (with over 17,000 generating units in the U.S. represented in the model) along with unit-level characteristics such as capacity, utilization, outages, emission rates and technology costs.
- The model can retire units if they cannot remain profitable, build new generating capacity to meet increasing electricity demand and reserve margin requirements. The operation of existing units by the model depends on the policies in place, electricity demand and operating costs (particularly energy prices).
- The model is solved for periods from 2023 to 2053 in 3-year time step.
- The Appendix provides more detail on the NewERA electric sector model

State-Level Delivered Electricity Rate Model

The rate model is a bottom-up construct that estimates ratepayer-specific delivered electricity price by state

- The rate model uses regional model outputs from the NewERA electricity sector model aggregated to state-level outputs to calculate delivered electricity sector prices.
- The delivered electricity prices in the rate model are estimated based on type of electricity market structure in state and the input components based on the type of structure
  - **Cost-of-Service (COS):** The input components include the incremental cost to serve load (operating plus investment costs), renewable energy credit (REC) costs as well as a return on equity.
  - **Competitive:** The input components include the wholesale, capacity and REC costs.
- Additionally, the calculation of delivered electricity prices for both types of market structure includes transmission losses and a rate-payer specific transmission and distribution (T&D) margin.
- The state-specific delivered electricity prices by ratepayer is calculated as a weighted average estimate based on the share of COS vs. competitive market share for the state.

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2

Overview of the Key Modeling Assumptions

ECONOMICS. EXPERTS. EXPERIENCE.

Overview of Technology-Neutral Tax Incentives

The technology-neutral tax incentives are broadly consistent with the U.S. EIA's AEO 2023 modeling assumptions

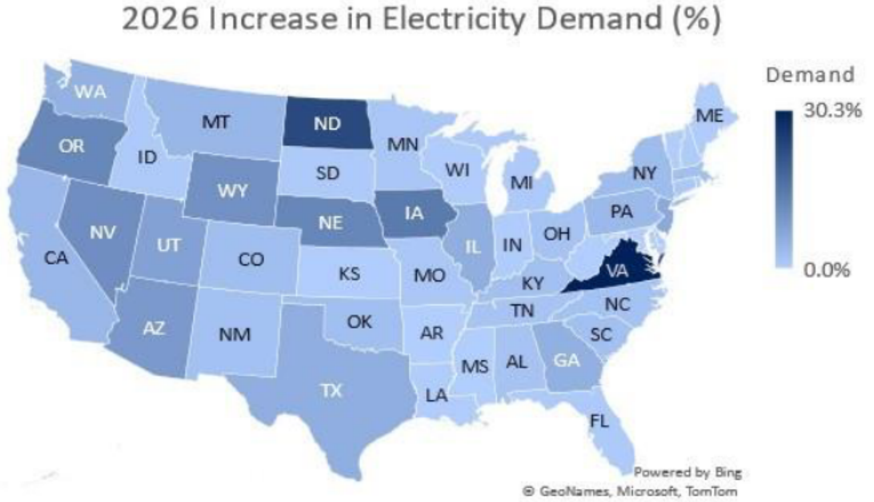
- For this study, two types of tax incentives are incorporated: §45Y production tax credit (PTC) and the §48E investment tax credit (ITC) to model the impact of the tax incentives on renewable technologies.
- The ITC was assumed to apply to capital-intensive technologies while the PTC was assumed to apply to other technologies. [1]
  - The PTC was applied to new solar PV, solar PV with storage, onshore wind, onshore wind with storage projects
  - The ITC was applied to new biomass, geothermal, hydroelectric, solar thermal, offshore wind and new nuclear
- The full value of the credit assumed to apply until 2033, 75% in 2034, 50% in 2035 and zero thereafter
- Additionally, the §45U zero-emission nuclear PTC was applied to existing nuclear resources with the full value of the credit assumed to apply from 2024 to 2032 and zero thereafter
- All technologies were assumed to be eligible for the base credit plus the bonus credits for prevailing wage and apprenticeship requirements.
- It was assumed that none of the technologies would be eligible for the bonus credits from meeting domestic content requirements (except for offshore wind) and bonus credits for location in energy communities.

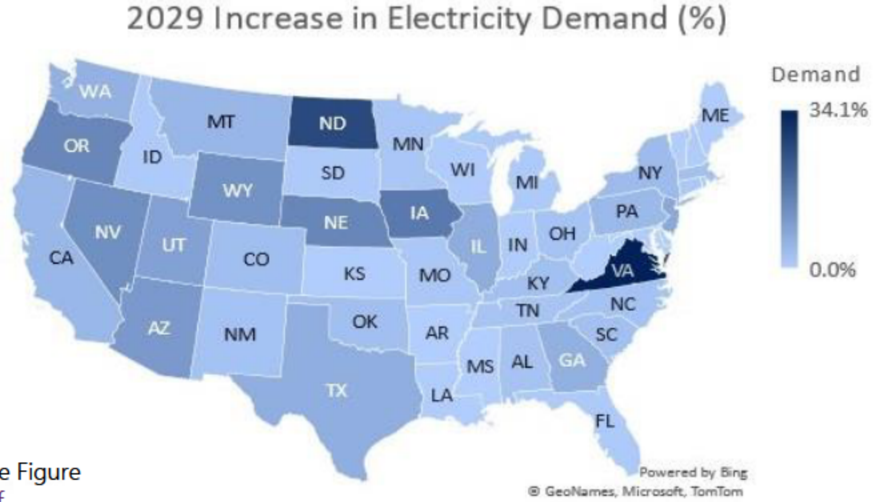
[1] U.S. EIA, AEO2023 Issues in Focus: Inflation Reduction Act Cases in the AEO2023, March 2023, available at https://www.eia.gov/outlooks/aeo/IIF_IRA/pdf/IRA_IIF.pdf;
U.S. EIA, Assumptions to the Annual Energy Outlook 2023: Renewable Fuels Module, March 2023, available at https://www.eia.gov/outlooks/aeo/assumptions/pdf/RFM_Assumptions.pdf

Incremental Electricity Demand from Data Center Growth

The incremental demand from data center growth have varying impacts on the regional electricity demand.

- NERA's assumption for the incremental demand from growth in data centers for this study are based on the Moderate Growth scenario in the 2024 EPRI study which uses a survey approach of expert assessment to forecast future demand.[1]
  - The EPRI study projects state level electricity consumption from U.S. data centers from 2023-2030 to grow at an average annual growth rate of 5% with incremental demand of about 179 TWh and 205 TWh in 2026 and 2029.
  - Moderate Growth scenario in the 2024 EPRI study is at the lower end of the academic and industry future projections of annual energy use by date centers.[2]
- The incremental electricity demand was assumed to be spread equally across all 8,760 hours in a year assuming the data centers run continuously consistent with their operations. Regional peak demand is increased by the average hourly incremental demand in a year.
- The U.S.-wide increase in total electricity demand (with the incremental demand from data center growth) is 4.3% (2026) and 4.8% (2029).



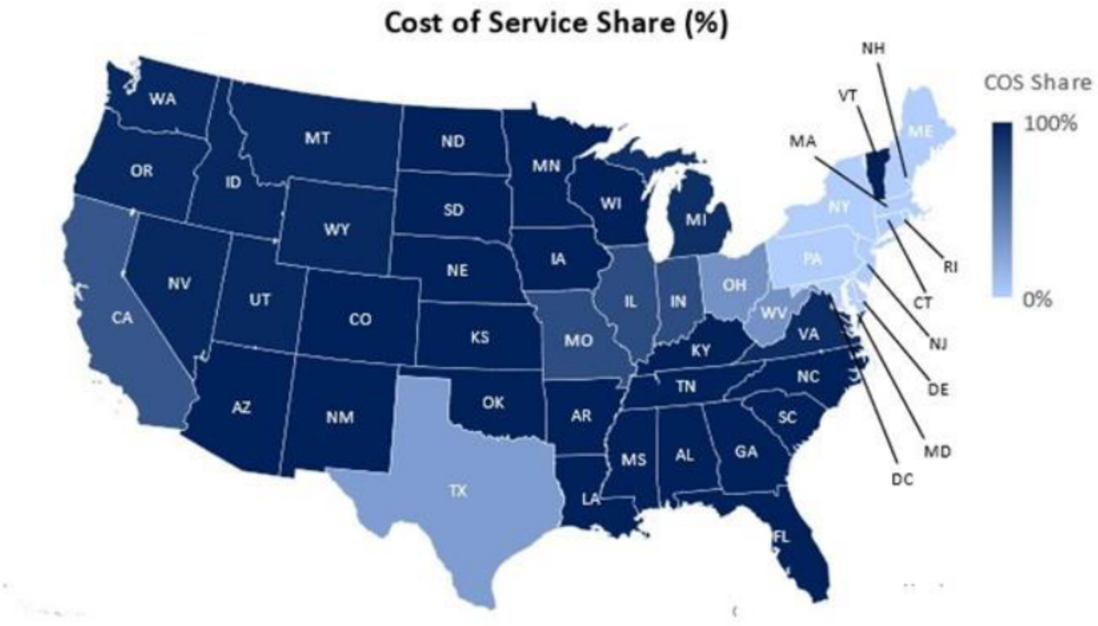


[1] EPRI, Powering Intelligence: Analyzing Artificial Intelligence and Data Center Energy Consumption, May 28, 2024, available at https://www.epri.com/research/products/3002028905
[2] Berkeley Lab, Energy Analysis & Environmental Impacts Division, 2023 United States Data Center Energy Usage Report, December 2024., See Figure 1.1., pg. 12, available at https://eta-publications.lbl.gov/sites/default/files/2024-12/lbnl-2024-united-states-data-center-energy-usage-report.pdf

Electricity Market Structure Assumptions

State-level electricity market structure are either cost-of-service and/or competitive.

- The electricity market structure of each individual state can be either cost-of-service and/or competitive.
- The share of demand (or generation) of cost-of-service or competitiv is based on EIA's AEO 2023 modeling assumptions.[1]
- Each state is located in a broader electricity market that is bigger thai the state in general. The state-level market impacts will be influenced by neighboring state impacts.
- Most of the states in the U.S. have either a fully cost-of-service or partial cost-of-service electricity market structure.
- States with a fully competitive electricity market structure are primaril concentrated in the Northeast.



[1] U.S. EIA, Assumptions to the Annual Energy Outlook 2023: Electricity Market Module, March 2023, available at https://www.eia.gov/outlooks/aeo/assumptions/pdf/EMM_Assumptions.pdf

3 Overview of Scenarios Analyzed

Scenarios Analyzed for Delivered Electricity Price Impacts from Tax Incentives

Two scenarios were analyzed for the study to assess the impacts of the technology-neutral tax incentives on delivered electricity prices.

Scenario	Electricity Demand	Technology-Neutral Tax Incentives
1. With Tax Incentives	Electricity demand from data centers	Includes technology-neutral tax incentives
2. Without Tax Incentives	Electricity demand from data centers	Excludes technology-neutral tax incentives

- The study evaluated two scenarios with and without different technology-neutral tax incentives for solar, solar with storage, solar thermal, onshore and offshore wind, geothermal, biomass, hydroelectric, and existing and new nuclear generating technologies.
- Both scenarios include incremental electricity demand from data centers.
- The technology-neutral tax incentives were applied to the eligible technologies in the scenario. The incentives have the effect of reducing the capital costs of the clean energy technologies.
- The electricity price impacts for this study are presented for two representative years (2026 and 2029).

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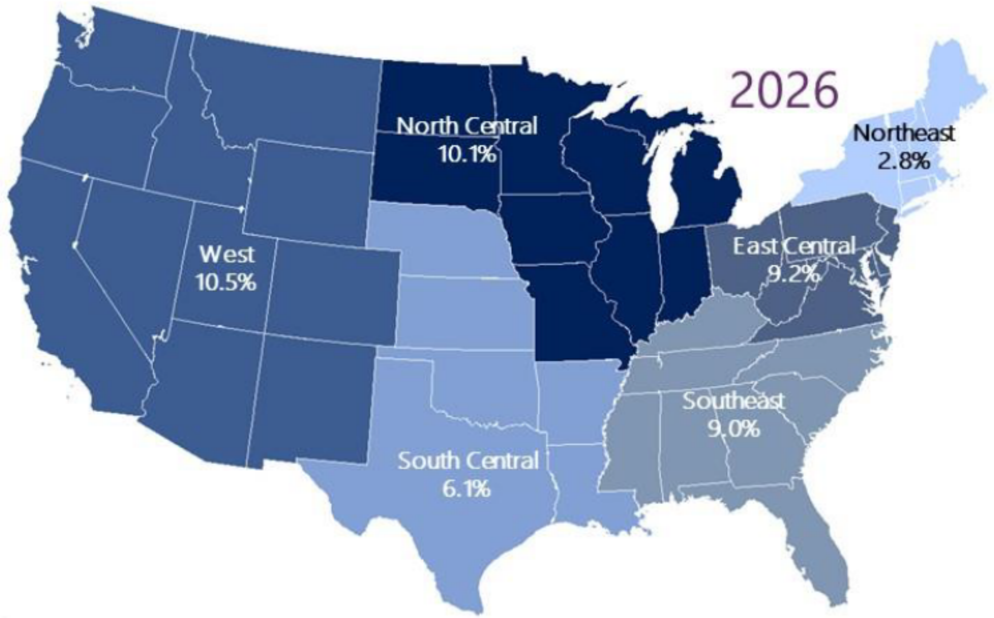
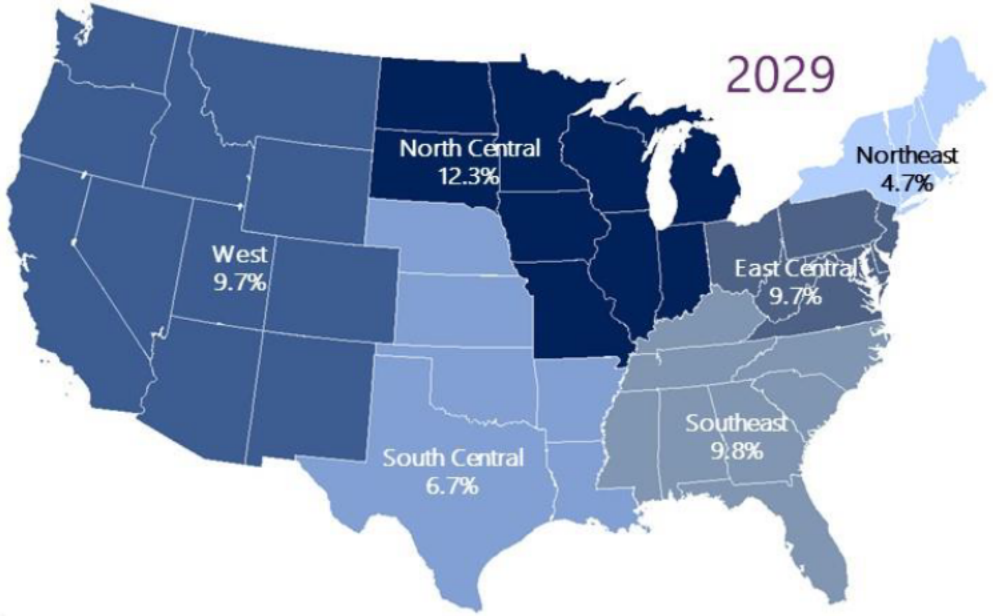
4

Summary of Delivered Electricity Price Impact Results

Average Delivered Electricity Price Impacts in 2026 and 2029, by Region

North Central and West regions are projected to see the highest increase in the average delivered electricity prices in the absence of the technology-neutral tax incentives. The impacts across the states within these broad regions are expected to vary based on the availability of deployment of low-cost generating technologies, substitution between new generation capacity incentivized by the technology-neutral tax credits and fossil fuel-based generation, and electricity market structure for that state.

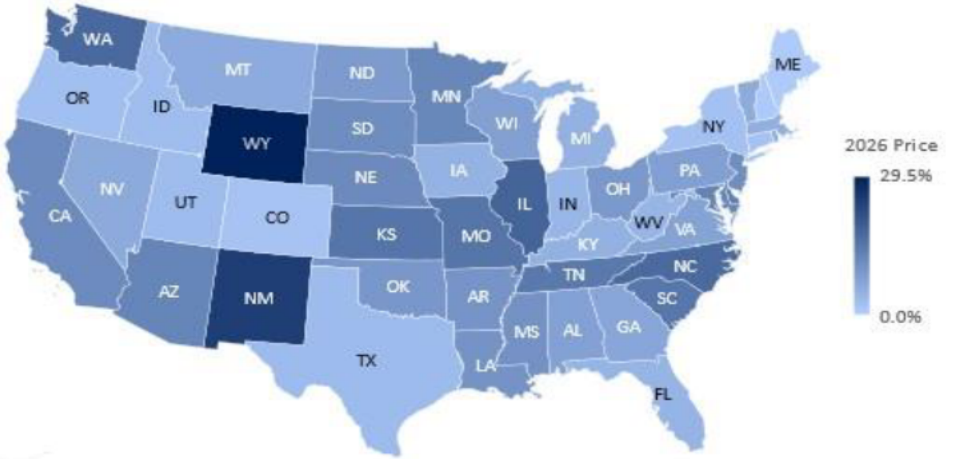


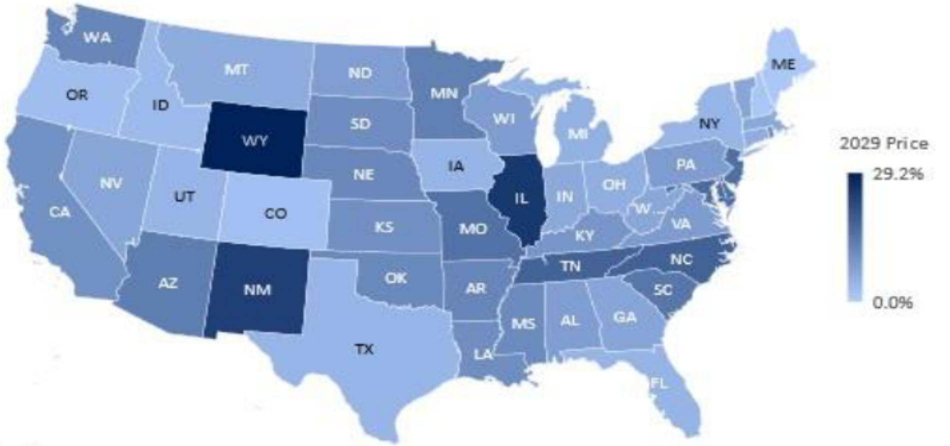


Average U.S. Electricity Price Impacts in 2026 and 2029, by State

The increase in average U.S. all-sector delivered electricity price in the absence of the technology-neutral tax incentives ranges from 0.4% to 29.5% in 2026 and 1.1% to 29.2% in 2029.

- The increase in average U.S. all-sector delivered electricity prices ranges from 0.4% (0.1¢/kWh*) to 29.5% (2.6¢/kWh) in 2026 and 1.1% (0.3¢/kWh) to 29.2% (2.7¢/kWh) in 2029 without the technology-neutral tax incentives.**
- Top 15 states with highest price impacts in 2026 are WY, NM, IL, DC, WA, NC, MO, KS, SC, TN. DE, MD, AZ, MN and NE.***
- Top 15 states with highest price impacts in 2029 are WY, IL, NM, NC, TN, MD, NJ, DE, MO, SC, AZ, MN, WA, AR, and NE.****
- Of these 8 are within the cost-of-service region, 3 are in the wholesale region, and rest of 4 are in the mixed electricity market structure region.
- The electricity price impacts in the states within a cost-of-service region are influenced by increase in capital costs associated with new fossil capacity additions and accompanying fuel costs from increase in capacity factor of fossil units; while electricity price impacts in the states in a competitive region are influenced by higher energy costs and renewable credit costs in scenario in the absence of the technology-neutral tax incentives.





** Prices are denominated in nominal dollars, unless specified otherwise.*
*** Values are absolute price changes for states with the highest/lowest percentage changes.*
**** These represent the top fifteen states that experience the largest % change in all-sector delivered electricity prices in 2029.*
***** These represent the top fifteen states that experience the largest % change in all-sector delivered electricity prices in 2029.*
Refer to the Appendix for the all-sector price impacts in 2026 and 2029 for the top 15 states, based on the absolute price changes

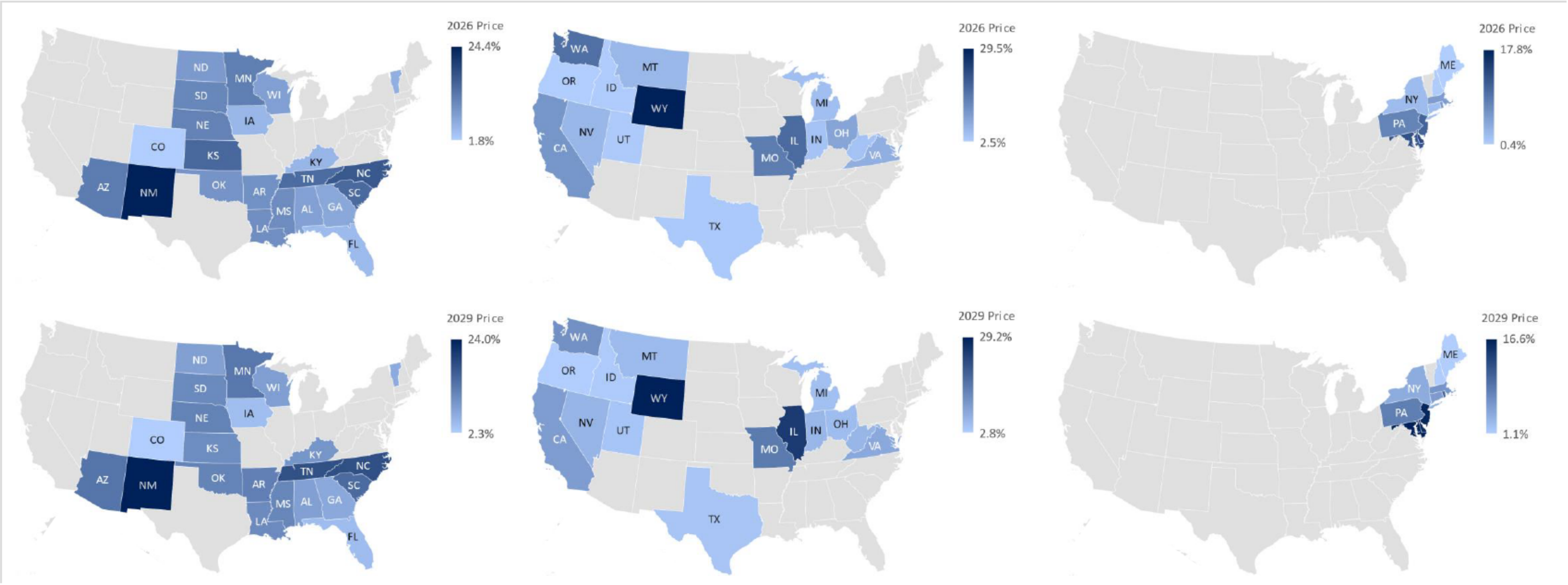
Average U.S. Electricity Price Impacts by Electricity Market Structure in 2026 and 2029

An increase in delivered electricity prices are projected for all states with varying types of electricity market structure.

Cost-Of-Service Market States | Mixed Market States | Competitive Market States

2026

2029

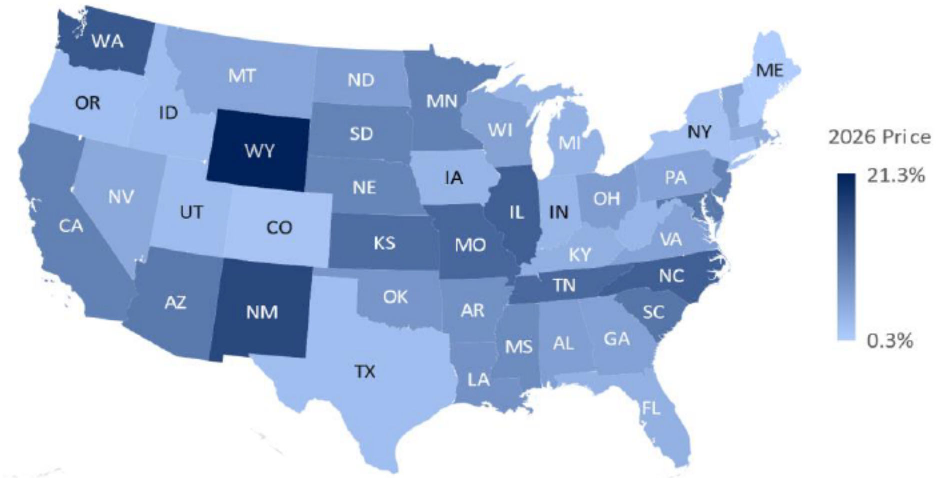


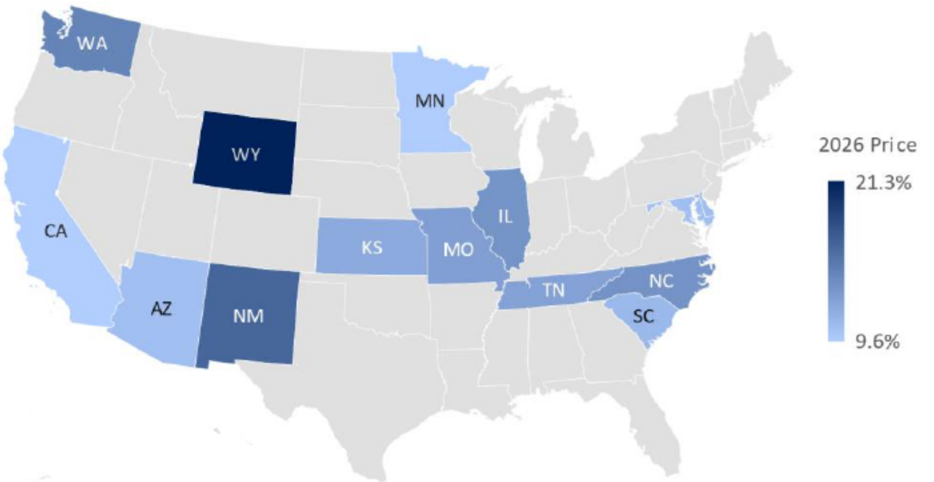
** See Appendix for detailed state-level results*

Residential Electricity Price Impacts in 2026

The increase in residential delivered electricity prices ranges from 0.3% to 21.3% in 2026 without the technology-neutral tax incentives.

- Residential delivered electricity prices are higher by 0.3% (0.08 ¢/kWh) to 21.3% (2.6 ¢/kWh) in 2026 in the scenario in the absence of the technology-neutral tax incentives compared to the scenario with these incentives.
- Top 15 states with highest residential price impacts (based on % change) are WY, DC, NM, WA, NC, IL, MO, TN, KS, SC, DE, AZ, MD, MN, and CA.*
- Of these states, 7 are within the COS region, 3 are in the wholesale region, and rest of 5 are in the mixed electricity market structure region.



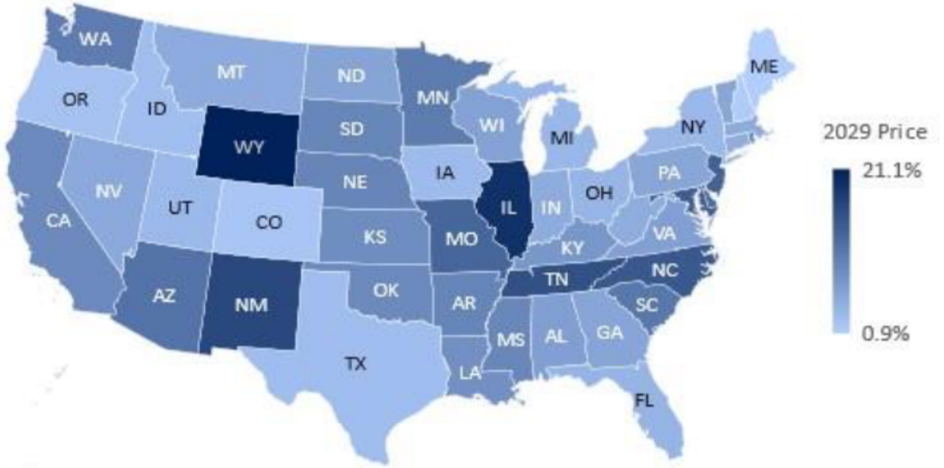


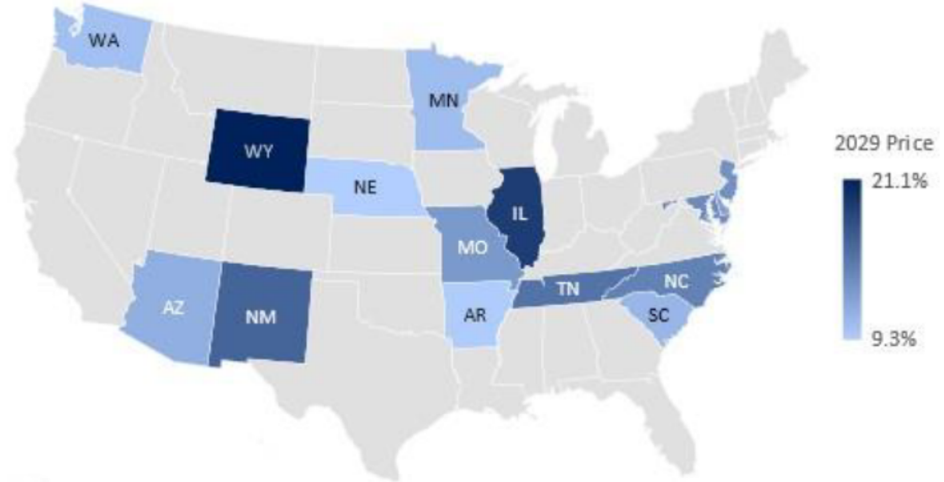
*Refer to the Appendix for the residential price impacts for the top 15 states in 2026, based on the absolute price changes

Residential Electricity Price Impacts in 2029

The increase in residential delivered electricity prices ranges from 0.9% to 21.1% in 2029 without the technology-neutral tax incentives.

- Residential delivered electricity price are higher by 0.9% (0.25 ¢/kWh) to 21.1% (2.7 ¢/kWh) in 2026 in the scenario in the absence of the technology-neutral tax incentives compared to the scenario with these incentives.
- Top 15 states with highest residential price impacts (based on % change) are WY, IL, NM, TN, NC, MD, NJ, MO, DE, AZ, SC, MN, WA, AR, and NE.*
- Of these states, 8 are within the COS region, 3 are in the wholesale region, and rest of 4 are in the mixed electricity market structure region.
- The range of electricity price impacts in 2026 and 2029 are similar. However, there is a change in the rank order of the price impacts by state due to new capacity build pattern changes across the states.





* *Refer to the Appendix for the residential price impacts for the top 15 states in 2029, based on the absolute price changes*

States With the Highest Residential Electricity Price Impacts (Based on % Change)

Percentage Increase in Average Residential Electricity Price, Top 15 States

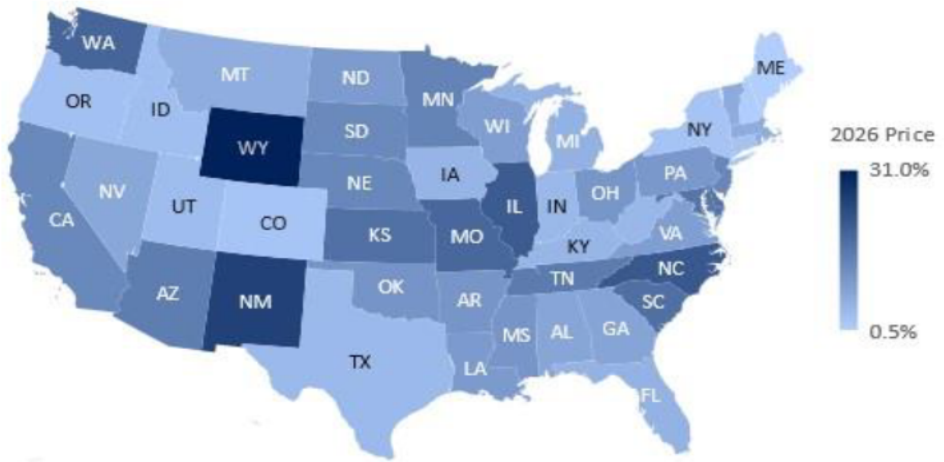
2026			2029		
State	**% Change**	**¢/kwh**	**State**	**% Change**	**¢/kwh**
WY	21.3%	2.6	WY	21.1%	2.7
DC	17.3%	3.1	IL	19.1%	3.2
NM	16.5%	2.6	NM	16.5%	2.7
WA	14.6%	1.6	TN	15.4%	1.9
NC	13.5%	1.8	NC	14.4%	2.0
IL	13.5%	2.1	MD	13.9%	2.7
MO	12.7%	1.6	NJ	13.4%	2.8
TN	12.5%	1.5	MO	12.9%	1.7
KS	12.0%	1.8	DE	12.3%	2.1
SC	10.9%	1.5	AZ	11.4%	1.8
DE	10.7%	1.8	SC	10.9%	1.6
AZ	10.6%	1.6	MN	10.4%	1.7
MD	10.6%	1.9	WA	10.2%	1.2
MN	9.6%	1.5	AR	9.4%	1.3
CA	9.6%	3.2	NE	9.3%	1.2

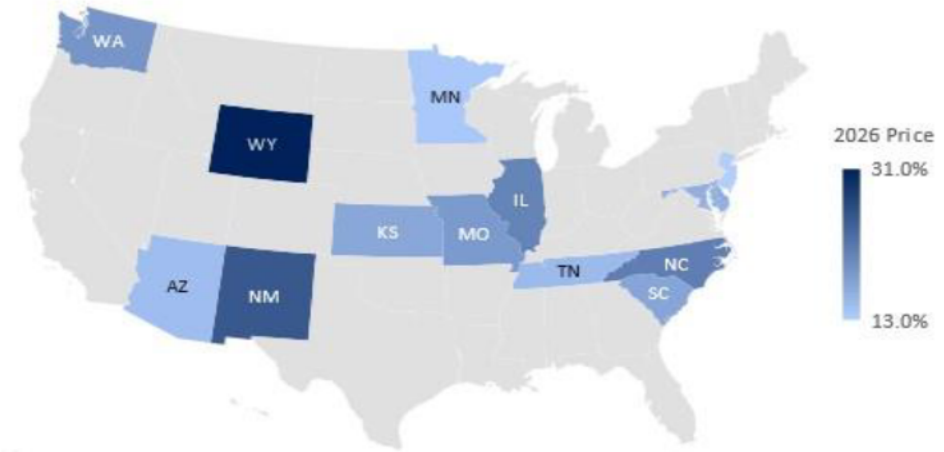
Note:
Prices are denominated in nominal dollars.
States are ranked by percentage change (%).

C&I Electricity Price Impacts in 2026

The increase in C&I delivered electricity prices ranges from 0.5% to 31.0% in 2026 without the technology-neutral tax incentives.

- C&I delivered electricity prices are higher by 0.5% (0.08 ¢/kWh) to 31.0% (2.6 ¢/kWh) in 2026 in the scenario in the absence of the technology-neutral tax incentives compared to the scenario with the incentives.
- Top 15 states with highest C&I price impacts (based on % change) are WY, NM, NC, IL, DC, WA, MO, SC, KS, DE, MD, TN, AZ, MN, and NJ.*
- Of these states, 7 are within the COS region, 4 are in the wholesale region, and rest of 4 are in the mixed electricity market structure region.



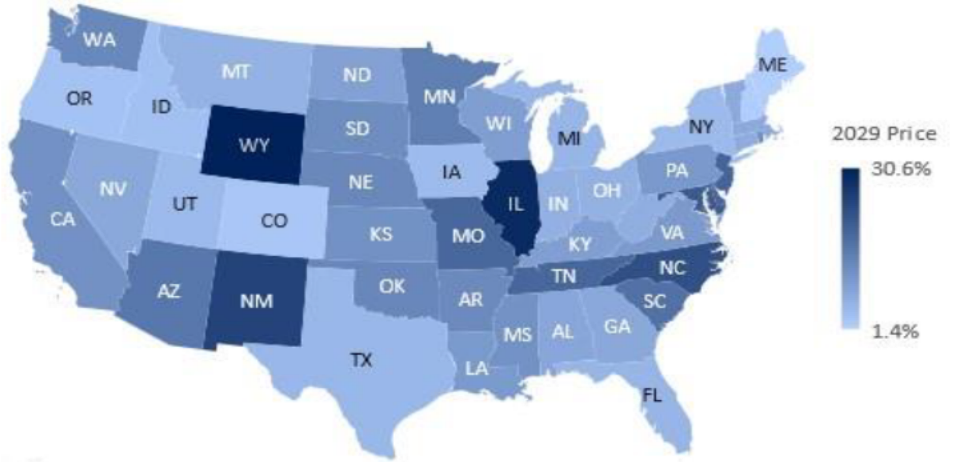


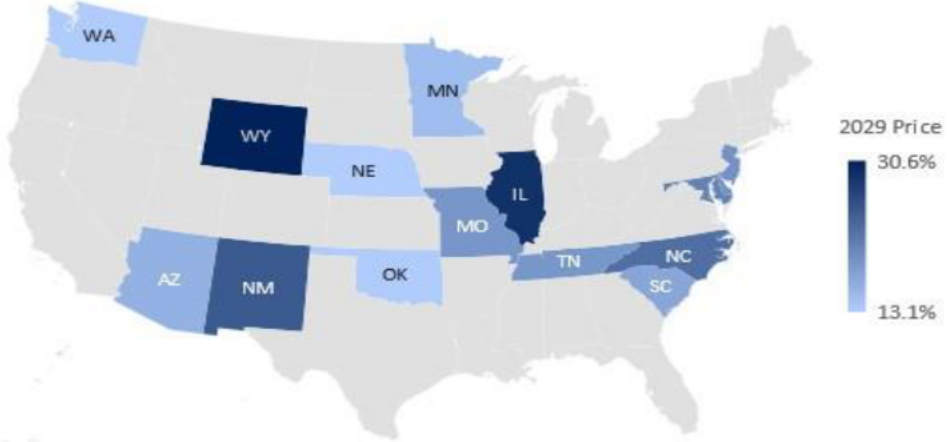
* Refer to the Appendix for the C&I price impacts for the top 15 states in 2026, based on the absolute price changes

C&I Electricity Price Impacts in 2029

The increase in residential delivered electricity prices ranges from 1.4% to 30.6% in 2029 without the technology-neutral tax incentives.

- C&I delivered electricity prices are higher by 1.4% (0.25 ¢/kWh) to 30.6% (2.7 ¢/kWh) in 2029 in the scenario in the absence of the technology-neutral tax incentives compared to the scenario with these tax incentives.
- Top 15 states with highest C&I price impacts (based on % change) are WY, IL, NM, NC, MD, NJ, DE, MO, TN, SC, AZ, MN, OK, WA, and NE.*
- Of these states, 8 are within the COS region, 3 are in the wholesale region, and rest of 4 are in the mixed electricity market structure region.
- The range of electricity price impacts in 2026 and 2029 are similar. However, there is a change in the rank order of the price impacts by state due to new capacity build pattern changes across the states.





* Refer to the Appendix for the C&I price impacts for the top 15 states in 2026, based on the absolute price changes

States With the Highest C&I Electricity Price Impacts (Based on % Change)

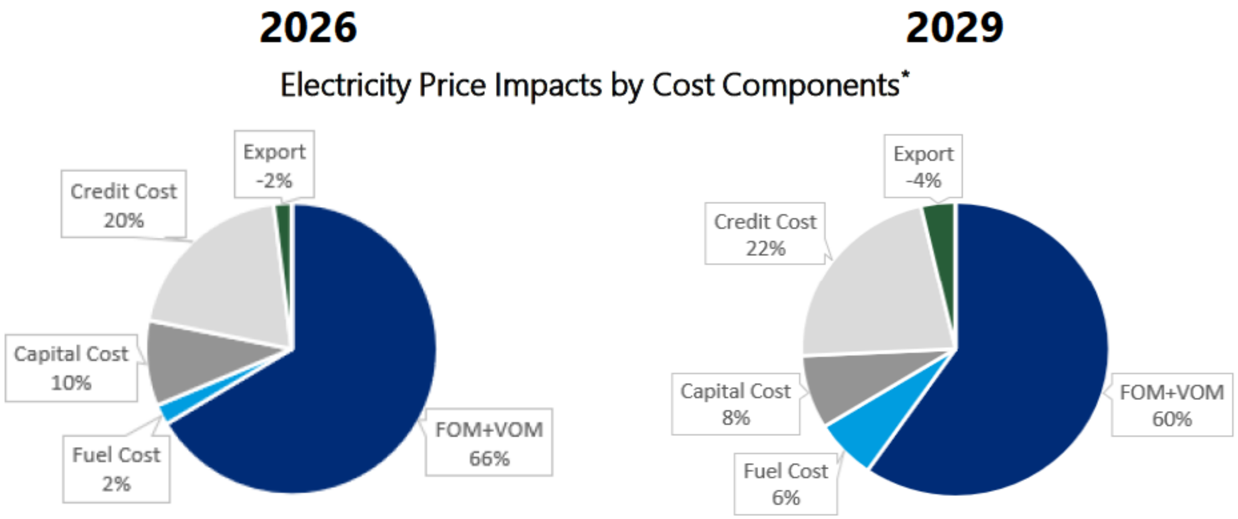
Percentage Increase in Average Commercial and Industrial Electricity Price
Top 15 States

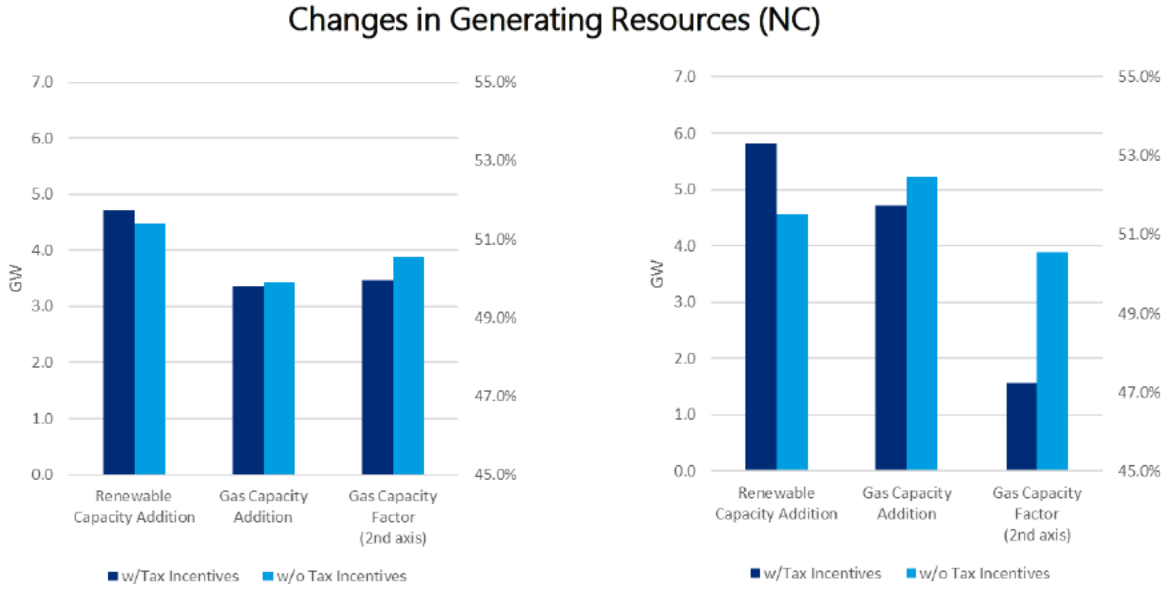
2026			2029		
State	**% Change**	**¢/kwh**	**State**	**% Change**	**¢/kwh**
WY	31.0%	2.6	WY	30.6%	2.7
NM	25.2%	2.6	IL	28.8%	3.2
NC	21.2%	1.8	NM	24.8%	2.7
IL	20.7%	2.1	NC	22.6%	2.0
DC	19.2%	3.1	MD	20.8%	2.7
WA	18.8%	1.6	NJ	19.1%	2.8
MO	18.4%	1.6	DE	19.0%	2.1
SC	17.2%	1.5	MO	18.7%	1.7
KS	16.9%	1.8	TN	18.6%	1.9
DE	16.6%	1.8	SC	17.0%	1.6
MD	16.2%	1.9	AZ	15.9%	1.8
TN	15.0%	1.5	MN	14.7%	1.7
AZ	14.7%	1.6	OK	13.2%	1.2
MN	13.6%	1.5	WA	13.2%	1.2
NJ	13.0%	2.0	NE	13.1%	1.2

Note:
Prices are denominated in nominal dollars.
States are ranked by percentage change (%)

North Carolina: Drivers of Electricity Price Impacts in a Cost-Of-Service Electricity Market Structure Region

- NC is projected to have about 2 to 4 TWh of incremental load from data centers - about 2% increase in the total load.
- In the absence of technology-neutral tax incentives, NC adds a lower amount of renewables with concomitant increase in gas capacity addition and an increase in the capacity factor of existing gas units.
- An increase in credit costs and operation and maintenance costs, primarily contribute to an increase in the electricity prices.
- The average all-sector delivered electricity price is projected to increase from 10.9 cents/kwh to 12.7 cents/kwh in 2026 (1.8 cents/kwh or ~17%) and from 11.3 cents/kwh to 13.4 cents/kwh in 2029 (1.6 cents/kwh or ~18%) in the absence of the technology-neutral tax incentives.





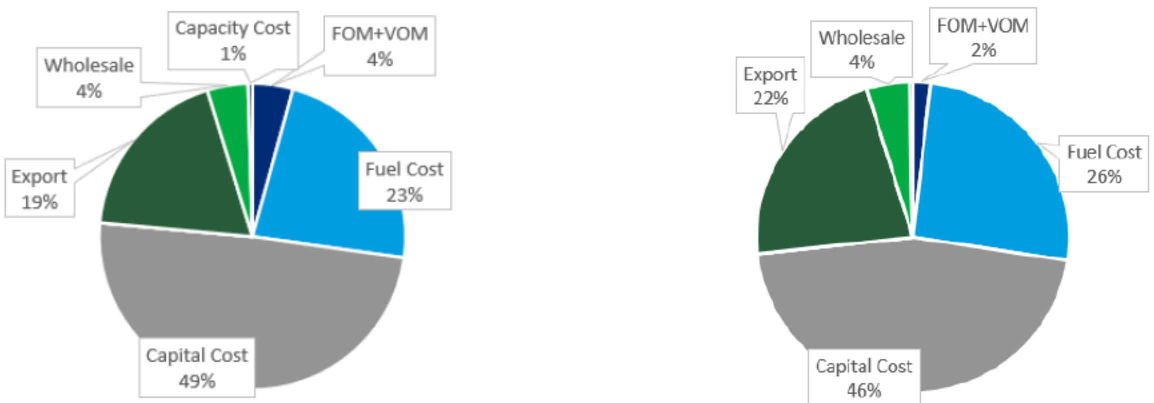
Note: *The results from the NewERA model are for broader regions known as power pools which are then disaggregated to state level results using a mapping of electricity demand from the power pools to individual states.*
** See Slides 44-45 for a description of the cost components*

Wyoming: Drivers of Electricity Price Impacts in a Mixed Electricity Market Structure Region

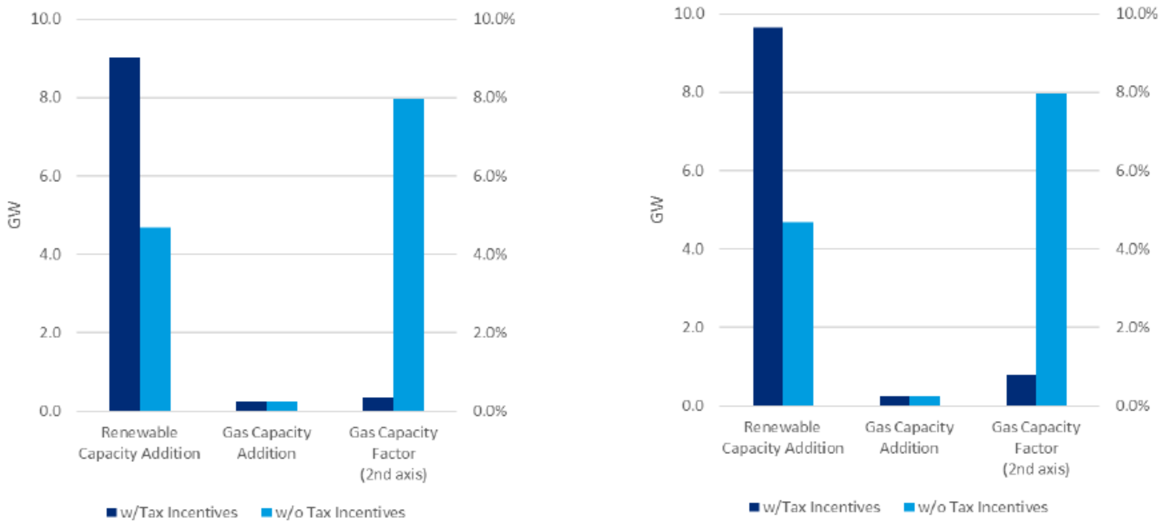
- WY is projected to have about 2.2 TWh of annual incremental load from data centers - about 11% average annual increase in the total load.
- In the absence of the technology-neutral tax incentives, there is a significant reduction in renewables capacity additions in WY – mainly onshore wind. Additionally, the capacity factor of existing natural gas increases to meet the state's electricity demand.
- Increase in the electricity prices are a result of an increase in fuel costs from increased natural gas use, increase in capital costs from the small increase in natural gas capacity, and increase in costs from reduction in exports.
- The average all-sector delivered electricity price is projected to increase from 8.9 ¢/kWh to 11.5 ¢/kWh in 2026 (2.6 ¢/kWh or ~30%) and from 9.3 ¢/kWh to 12 ¢/kWh in 2029 (2.7 ¢/kWh or 29%) in the absence of the technology-neutral tax incentives.

2026 **2029**

Electricity Price Impacts by Cost Components*



Changes in Generating Resources (WY)



Note: *The results from the NewERA model are for broader regions known as power pools which are then disaggregated to state level results using a mapping of electricity demand from the power pools to individual states.*

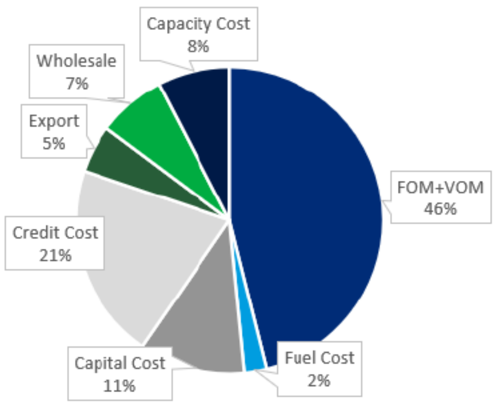
** See Slides 44-45 for a description of the cost components*

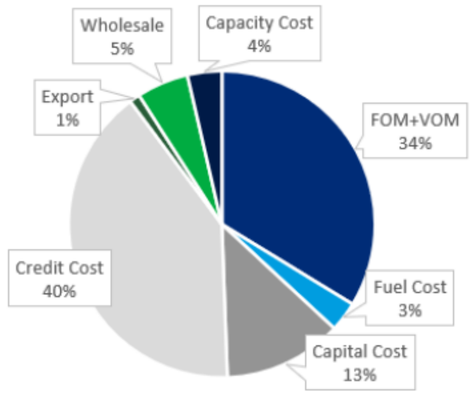
Illinois: Drivers of Electricity Price Impacts in a Mixed Electricity Market Structure Region

- IL is projected to have about 9 TWh of annual incremental load from data centers - about 5.7% average annual increase in the total load.
- In the absence of the technology-neutral tax incentives, there is an increase in the capacity factor of natural gas generation and fewer coal capacity retirements. Further, higher-cost renewable builds are still needed to meet the renewable portfolio standards in IL.
- The increase in the electricity prices is driven by the increase in renewable credit costs, the higher operating costs of coal and natural gas units and the higher capital costs of the renewable builds in the absence of the technology-neutral tax incentives.
- The average all-sector delivered electricity price is projected to increase from 11.9 ¢/kWh to 14.1 ¢/kWh in 2026 (2.2 ¢/kWh or ~18%) and from 13 ¢/kWh to 16.2 ¢/kWh in 2029 (3.2 ¢/kWh or 25%) in the absence of the technology-neutral tax incentives.

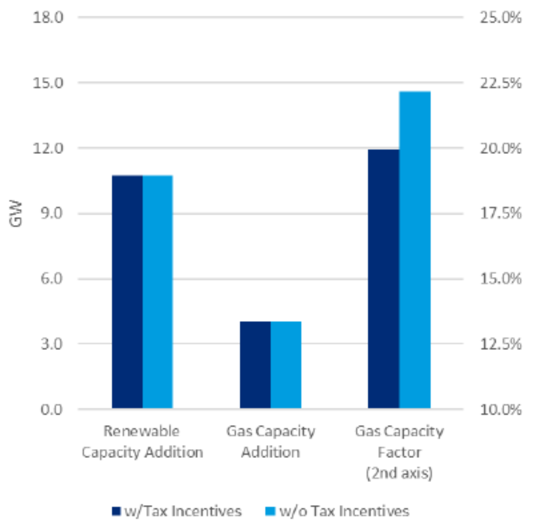
2026 **2029**

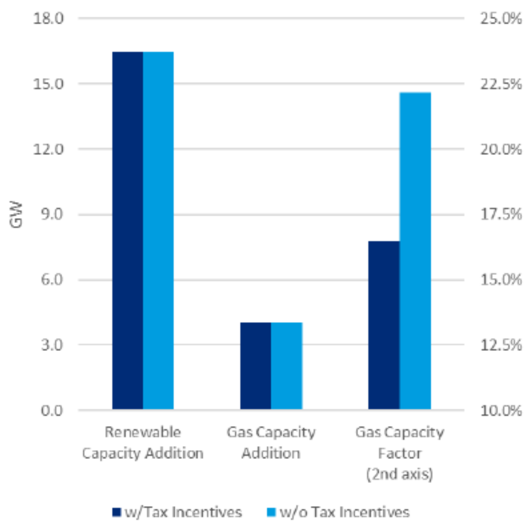
Electricity Price Impacts by Cost Components*





Changes in Generating Resources (IL)



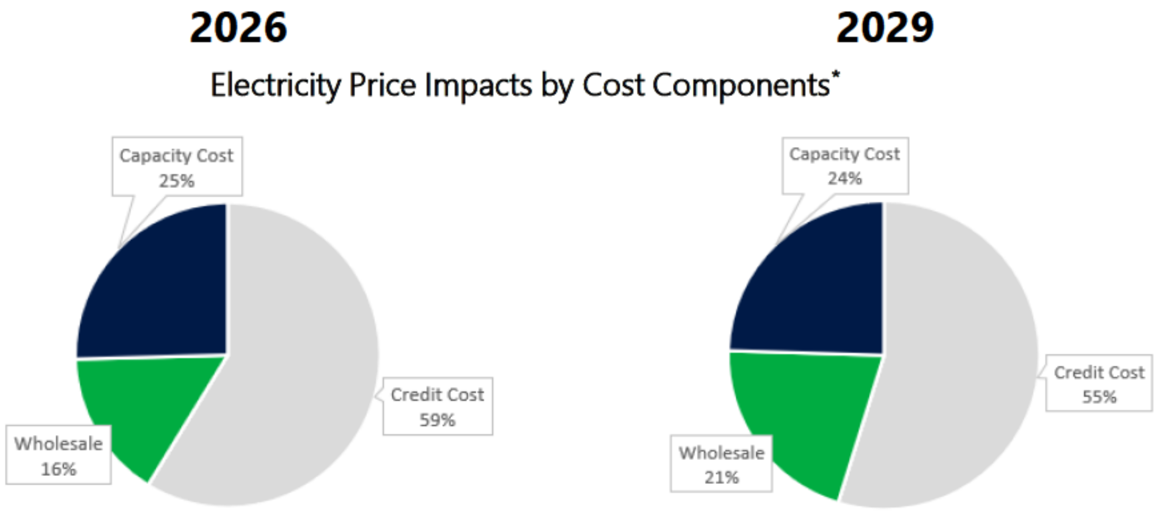


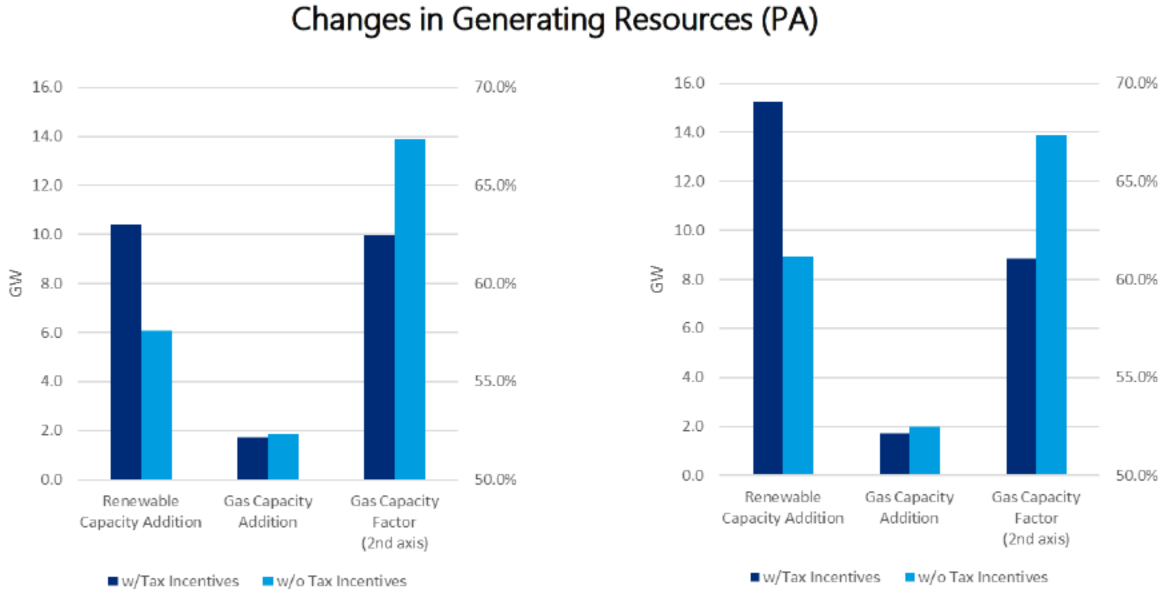
Note: The results from the NewERA model are for broader regions known as power pools which are then disaggregated to state level results using a mapping of electricity demand from the power pools to individual states.

** See Slides 44-45 for a description of the cost components*

Pennsylvania: Drivers of Price Impacts in a Competitive Electricity Market Structure Region

- PA is projected to have about 4.5 to 6.5 TWh of annual incremental load from data centers - about 3.5% average annual increase in the total load.
- In the absence of technology-neutral tax incentives, there is a significant reduction in renewables capacity additions in PA – a combination of onshore wind and solar. Additionally, capacity factor of existing natural gas increases to meet the state's electricity demand.
- The increase in electricity prices are a result of higher wholesale electricity costs, higher REC costs associated with higher cost of renewables to meet the state's RPS, and higher capacity prices.
- The average all-sector delivered electricity price is projected to increase from 12.4 ¢/kWh to 13.4 ¢/kWh in 2026 (1 ¢/kWh or ~8%) and from 13.1 ¢/kWh to 14.1 ¢/kWh in 2029 (1 ¢/kWh or ~8%) in the absence of the technology-neutral tax incentives.



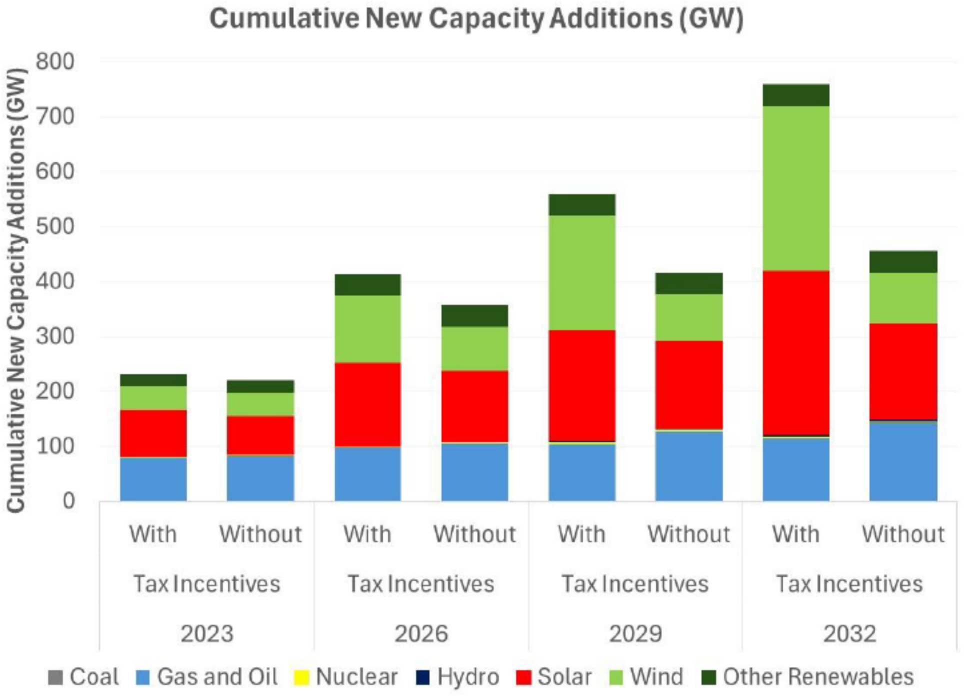


Note: The results from the NewERA model are for broader regions known as power pools which are then disaggregated to state level results using a mapping of electricity demand from the power pools to individual states.
** See Slides 44-45 for a description of the cost components*

New Capacity Additions by Type of Generating Technology

A lower amount of new clean energy technologies is added in the absence of the technology-neutral tax incentives,.

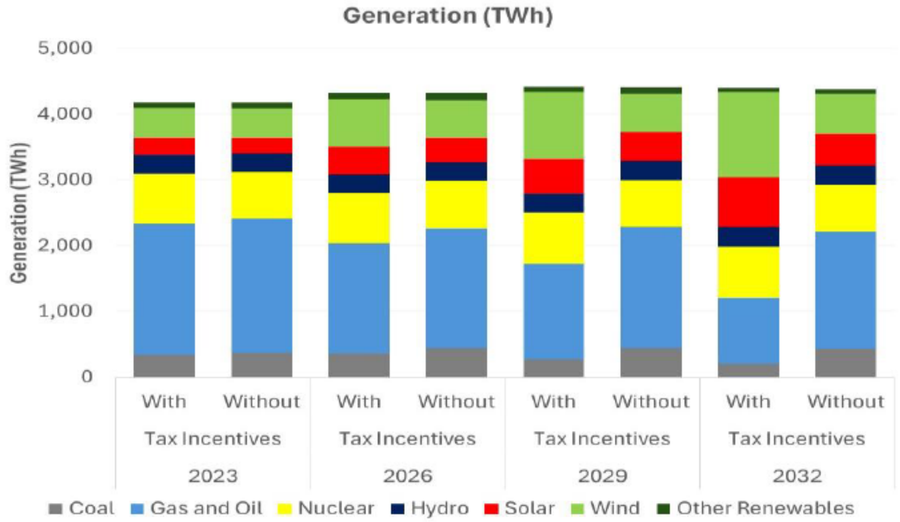
- New generation capacity incentivized by the technology-neutral tax credits are relatively more expensive in the scenario without the tax incentives which leads to lesser amount of new capacity additions of these technologies.
- By 2026 and 2029, there is a total reduction of 64 GW and 168 GW of solar and wind capacity additions respectively in the absence of the tax incentives.
- By 2026 and 2029, there is a total increase of about 7 GW and 23 GW of fossil new capacity additions respectively in the absence of the tax incentives.

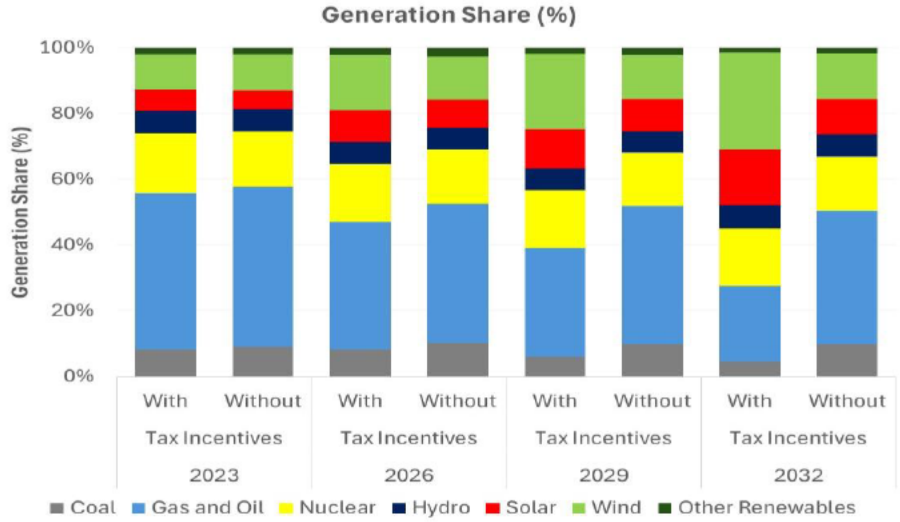


Generation by Type of Generating Technology

Clean energy technologies are disincentivized in the absence of the technology-neutral tax incentives.

- In the absence of technology-neutral generation, renewables are relative more expensive in the scenario with the incentives with a lesser amount of new capacity is built.
- Renewable resources are disincentivized resulting in a reduction of total available clean energy capacity.
- Reduction in generation from renewables, primarily solar and wind generation, amounts to about 187 TWh in 2026 and 503 TWh in 2029.





5

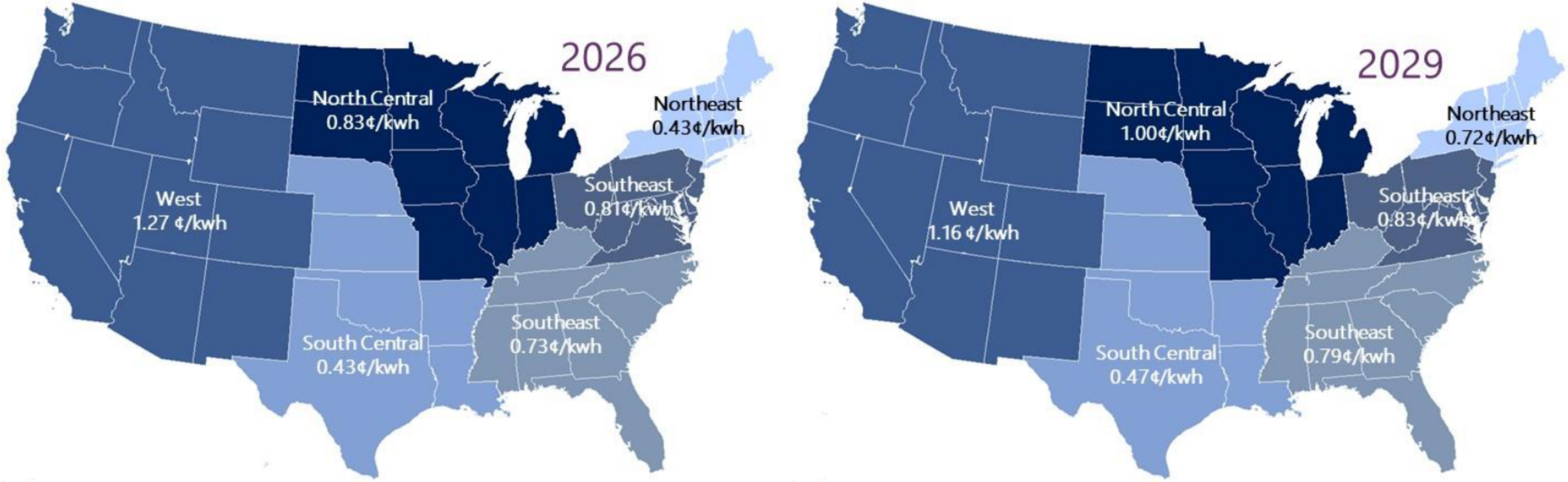
Appendix:
Additional Results
About the N_{ew}ERA Model
Technology-Neutral Tax Incentives

NERA

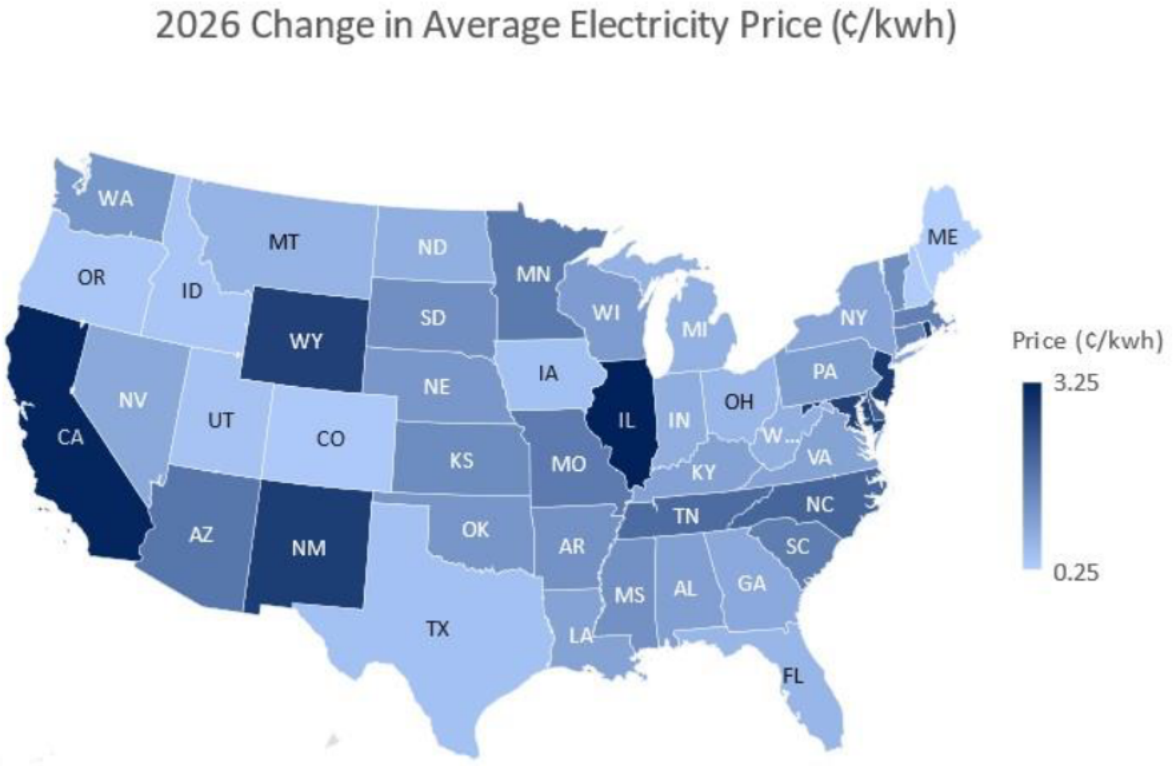
ECONOMICS. EXPERTS. EXPERIENCE.

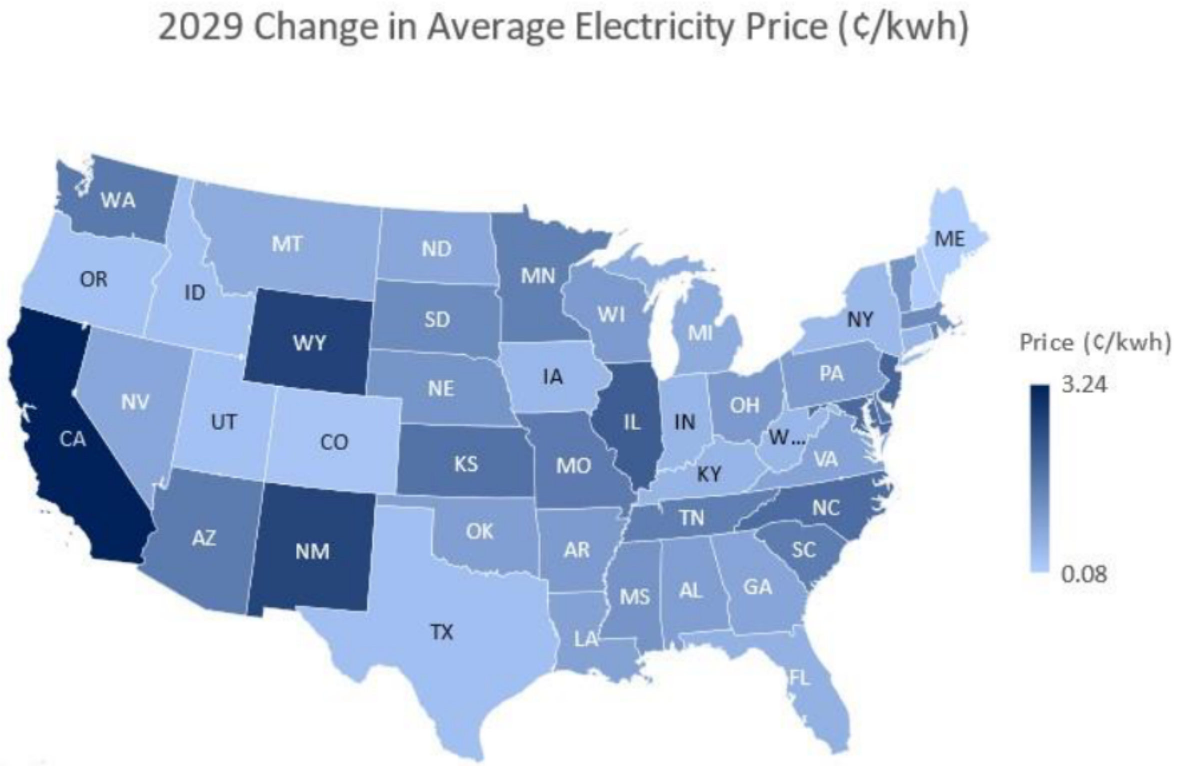
Additional Results: Average Delivered Electricity Price Impacts in 2026 and 2029, by Region (cents/kwh)

North Central and West regions are projected to see the highest increase in the average delivered electricity prices without the technology-neutral tax incentives. The impacts across the states within these broad regions will varying.

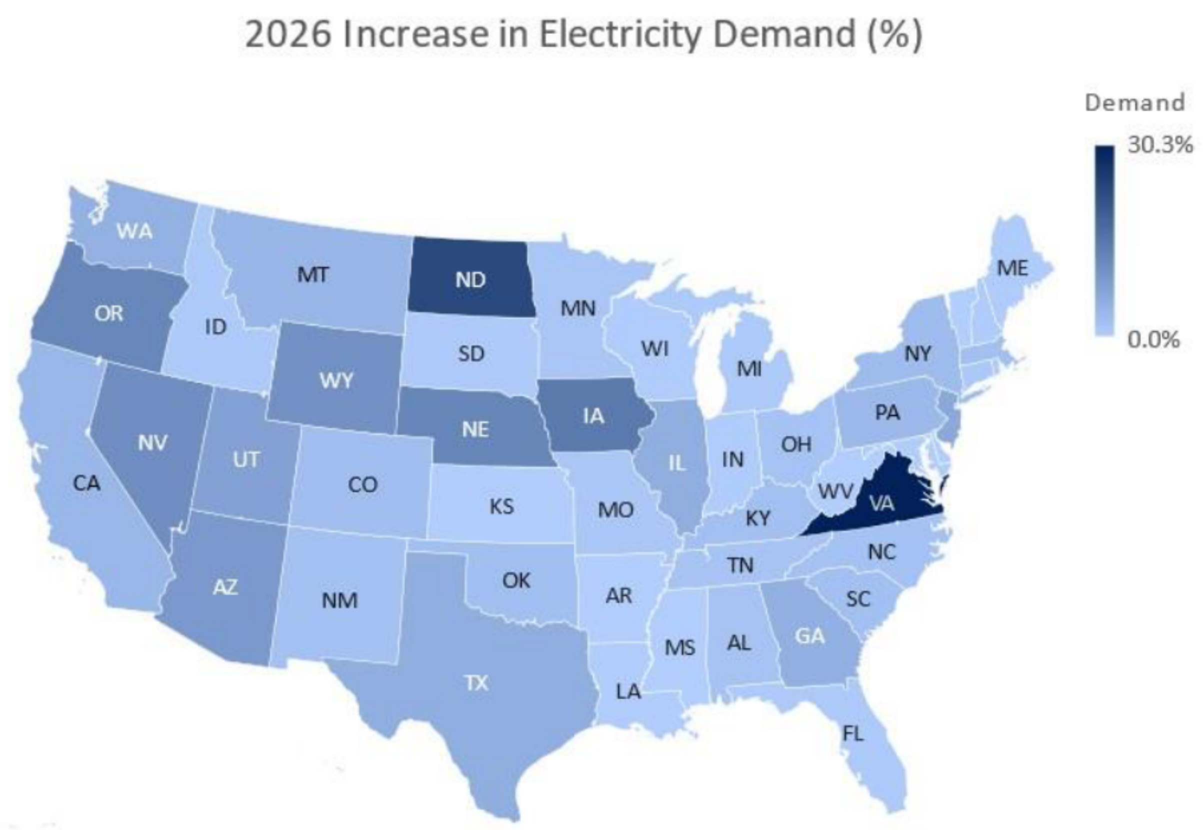


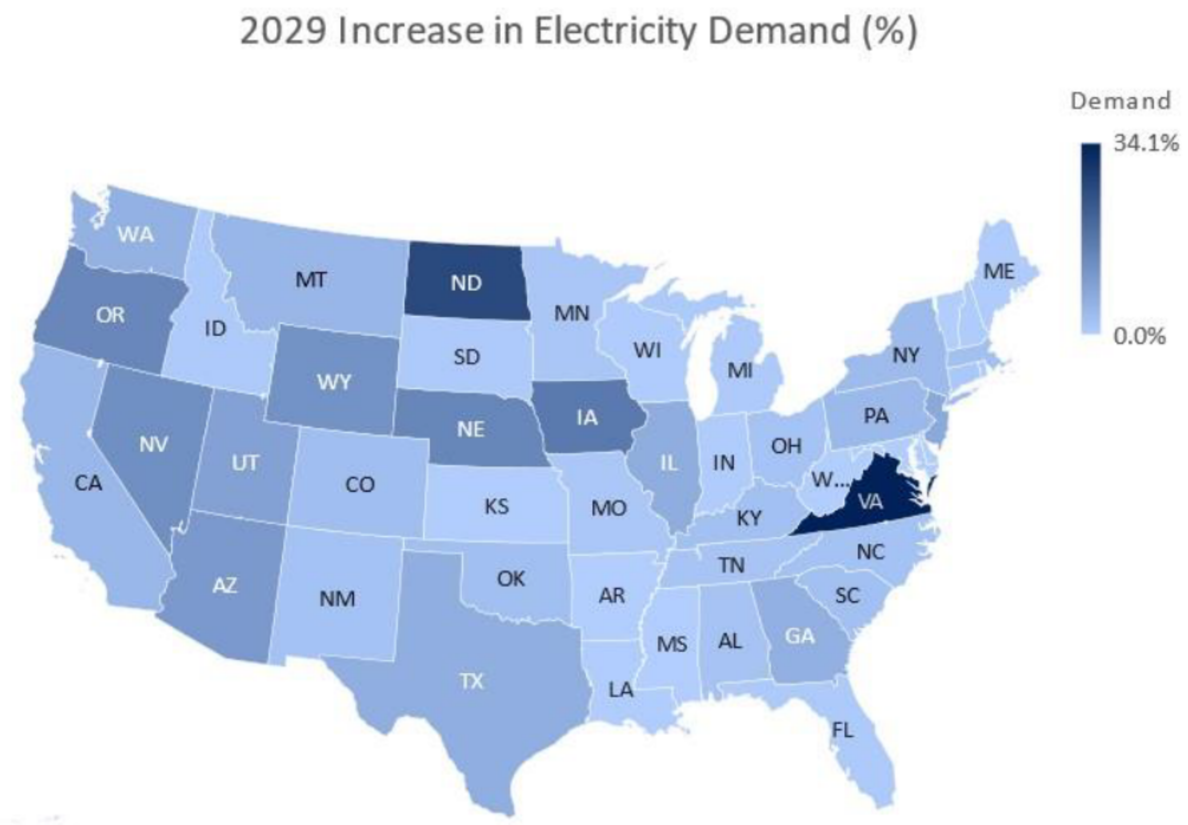
Additional Results: Average Delivered Electricity Price Impacts in 2026 and 2029, by State (cents/kwh)



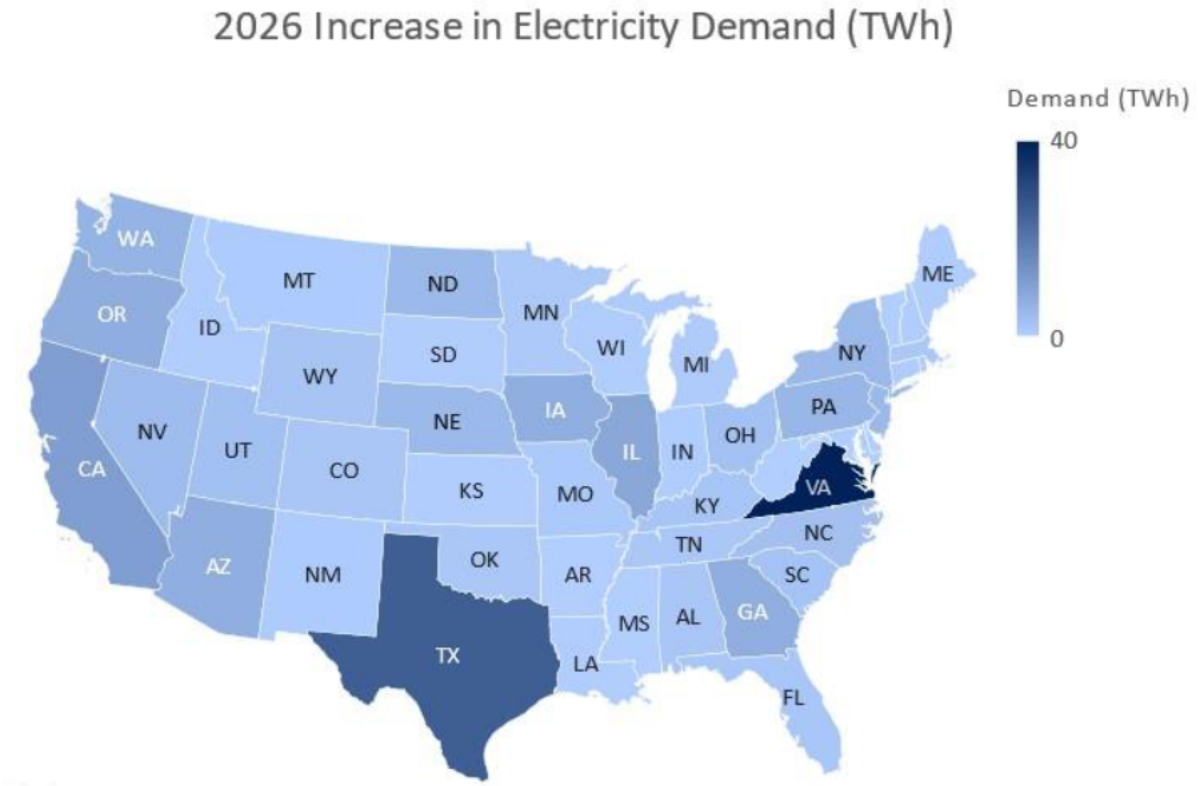


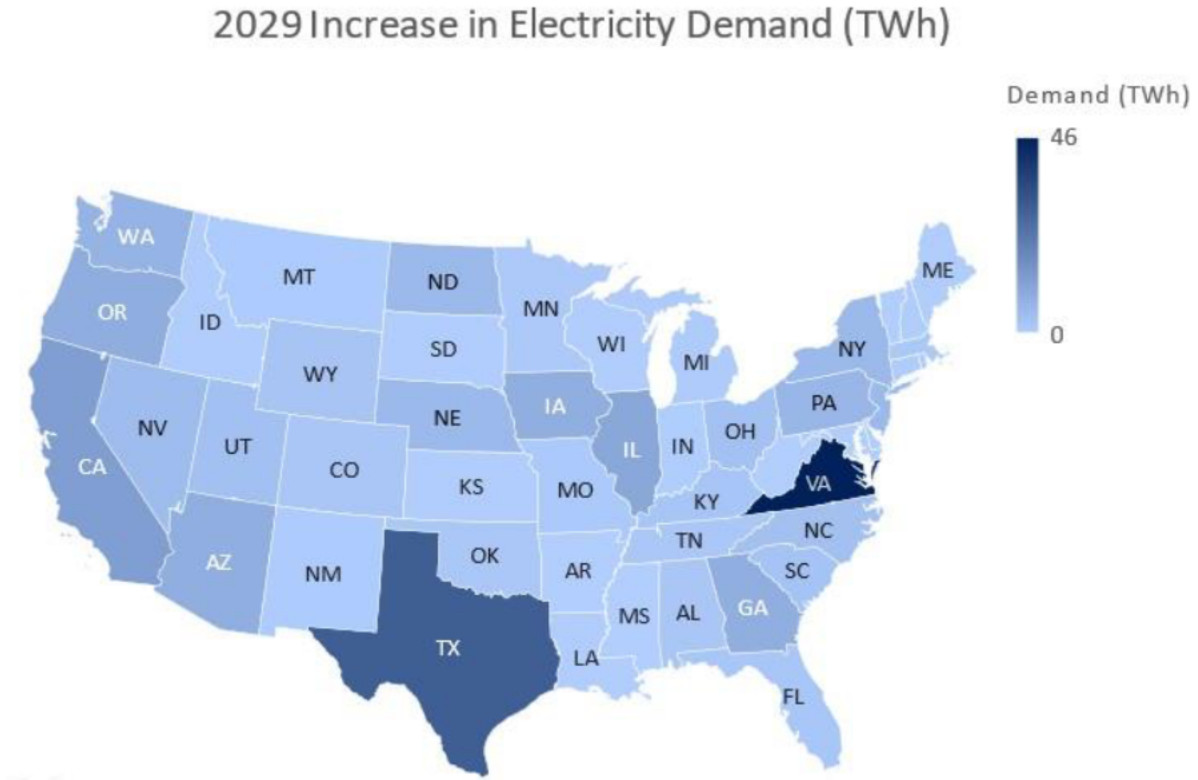
Additional Results: Increase in Electricity Demand from Data Centers





Additional Results: Increase in Electricity Demand from Data Centers





Additional Results: Residential Electricity Price Impacts for the Top 15 States

Percentage Increase in Average Residential Electricity Price
Top 15 States

2026			2029		
State	% Change	¢/kwh	State	% Change	¢/kwh
WY	21.3%	2.6	WY	21.1%	2.7
DC	17.3%	3.1	IL	19.1%	3.2
NM	16.5%	2.6	NM	16.5%	2.7
WA	14.6%	1.6	TN	15.4%	1.9
NC	13.5%	1.8	NC	14.4%	2.0
IL	13.5%	2.1	MD	13.9%	2.7
MO	12.7%	1.6	NJ	13.4%	2.8
TN	12.5%	1.5	MO	12.9%	1.7
KS	12.0%	1.8	DE	12.3%	2.1
SC	10.9%	1.5	AZ	11.4%	1.8
DE	10.7%	1.8	SC	10.9%	1.6
AZ	10.6%	1.6	MN	10.4%	1.7
MD	10.6%	1.9	WA	10.2%	1.2
MN	9.6%	1.5	AR	9.4%	1.3
CA	9.6%	3.2	NE	9.3%	1.2

Note: States are ranked by percentage change (%).

** Prices are denominated in nominal dollars.*

Increase in Average Residential Electricity Price
Top 15 States

2026			2029		
State	¢/kwh	% Change	State	¢/kwh	% Change
CA	3.2	9.6%	IL	3.2	19.1%
DC	3.1	17.3%	CA	3.2	8.8%
WY	2.6	21.3%	RI	2.8	8.7%
NM	2.6	16.5%	NJ	2.8	13.4%
IL	2.1	13.5%	NM	2.7	16.5%
NJ	2.0	9.3%	WY	2.7	21.1%
MD	1.9	10.6%	MD	2.7	13.9%
NC	1.8	13.5%	DE	2.1	12.3%
DE	1.8	10.7%	NC	2.0	14.4%
KS	1.8	12.0%	TN	1.9	15.4%
WA	1.6	14.6%	AZ	1.8	11.4%
AZ	1.6	10.6%	MN	1.7	10.4%
MO	1.6	12.7%	MO	1.7	12.9%
SC	1.5	10.9%	SC	1.6	10.9%
TN	1.5	12.5%	MA	1.6	4.9%

Note: States are ranked by ¢/kwh.

Additional Results: C&I Electricity Price Impacts for the Top 15 States

Percentage Increase in Average Commercial and Industrial Electricity Price
Top 15 States

2026			2029		
State	% Change	¢/kwh	State	% Change	¢/kwh
WY	31.0%	2.6	WY	30.6%	2.7
NM	25.2%	2.6	IL	28.8%	3.2
NC	21.2%	1.8	NM	24.8%	2.7
IL	20.7%	2.1	NC	22.6%	2.0
DC	19.2%	3.1	MD	20.8%	2.7
WA	18.8%	1.6	NJ	19.1%	2.8
MO	18.4%	1.6	DE	19.0%	2.1
SC	17.2%	1.5	MO	18.7%	1.7
KS	16.9%	1.8	TN	18.6%	1.9
DE	16.6%	1.8	SC	17.0%	1.6
MD	16.2%	1.9	AZ	15.9%	1.8
TN	15.0%	1.5	MN	14.7%	1.7
AZ	14.7%	1.6	OK	13.2%	1.2
MN	13.6%	1.5	WA	13.2%	1.2
NJ	13.0%	2.0	NE	13.1%	1.2

Note: States are ranked by percentage change (%).

** Prices are denominated in nominal dollars.*

Increase in Average Commercial and Industrial Electricity Price
Top 15 States

2026			2029		
State	¢/kwh	% Change	State	¢/kwh	% Change
CA	3.2	12.8%	IL	3.2	28.8%
DC	3.1	19.2%	CA	3.2	11.6%
WY	2.6	31.0%	RI	2.8	12.4%
NM	2.6	25.2%	NJ	2.8	19.1%
IL	2.1	20.7%	NM	2.7	24.8%
NJ	2.0	13.0%	WY	2.7	30.6%
MD	1.9	16.2%	MD	2.7	20.8%
NC	1.8	21.2%	DE	2.1	19.0%
DE	1.8	16.6%	NC	2.0	22.6%
KS	1.8	16.9%	TN	1.9	18.6%
WA	1.6	18.8%	AZ	1.8	15.9%
AZ	1.6	14.7%	MN	1.7	14.7%
MO	1.6	18.4%	MO	1.7	18.7%
SC	1.5	17.2%	SC	1.6	17.0%
TN	1.5	15.0%	MA	1.6	7.4%

Note: States are ranked by ¢/kwh.

Additional Results: All-Sector Electricity Price Impacts for the Top 15 States

Percentage Increase in Average All-Sector Electricity Price
Top 15 States

2026			2029		
State	% Change	¢/kwh	State	% Change	¢/kwh
WY	29.5%	2.6	WY	29.2%	2.7
NM	24.4%	2.6	IL	25.1%	3.2
IL	17.9%	2.1	NM	24.0%	2.7
DC	17.8%	3.1	NC	18.1%	2.0
WA	17.1%	1.6	TN	17.9%	1.9
NC	17.0%	1.8	MD	16.6%	2.7
MO	15.2%	1.6	NJ	15.9%	2.8
KS	15.1%	1.8	DE	15.4%	2.1
SC	14.8%	1.5	MO	15.4%	1.7
TN	14.5%	1.5	SC	14.6%	1.6
DE	13.5%	1.8	AZ	13.4%	1.8
MD	12.7%	1.9	MN	13.0%	1.7
AZ	12.4%	1.6	WA	12.0%	1.2
MN	12.0%	1.5	AR	12.0%	1.3
NE	11.5%	1.1	NE	11.7%	1.2

Note: States are ranked by percentage change (%).

** Prices are denominated in nominal dollars.*

Increase in Average All-Sector Electricity Price
Top 15 States

2026			2029		
State	¢/kwh	% Change	State	¢/kwh	% Change
CA	3.2	11.3%	IL	3.2	25.1%
DC	3.1	17.8%	CA	3.2	10.3%
WY	2.6	29.5%	RI	2.8	10.5%
NM	2.6	24.4%	NJ	2.8	15.9%
IL	2.1	17.9%	NM	2.7	24.0%
NJ	2.0	10.9%	WY	2.7	29.2%
MD	1.9	12.7%	MD	2.7	16.6%
NC	1.8	17.0%	DE	2.1	15.4%
DE	1.8	13.5%	NC	2.0	18.1%
KS	1.8	15.1%	TN	1.9	17.9%
WA	1.6	17.1%	AZ	1.8	13.4%
AZ	1.6	12.4%	MN	1.7	13.0%
MO	1.6	15.2%	MO	1.7	15.4%
SC	1.5	14.8%	SC	1.6	14.6%
TN	1.5	14.5%	MA	1.6	6.1%

Note: States are ranked by ¢/kwh.

Additional Results: New Capacity Additions, Retirements, and Generation in 2026 and 2029

Cumulative New Capacity Additions (GW)*

	With Tax Incentives		Without Tax Incentives	
	2026	2029	2026	2029
Solar	153	201	131	158
Wind	122	209	80	85
Nuclear**	2	3	2	3
Other Renewables	5	8	6	8
Standalone Storage	35	36	35	36
Fossil	98	104	105	128
Total	**414**	**561**	**358**	**417**

** Both scenarios include electricity demand from data centers*

*** Includes the forced additions of the Palisades and Three Mile Island nuclear plants in 2025 and 2028 respectively*

Cumulative Retirements (GW)*

	With Tax Incentives		Without Tax Incentives	
	2026	2029	2026	2029
Coal	100	117	87	98
Gas and Oil	73	80	72	76
Nuclear	2	2	8	10
Total	**175**	**199**	**167**	**183**

** Both scenarios include electricity demand from data centers*

Generation by Fuel Type (TWh)*

	With Tax Incentives		Without Tax Incentives	
	2026	2029	2026	2029
Coal	356	270	443	436
Gas and Oil	1,680	1,457	1,826	1,848
Nuclear	765	773	715	713
Hydroelectric	285	297	286	297
Renewables	1,242	1,620	1,055	1,117
Total	**4,328**	**4,417**	**4,325**	**4,412**

** Both scenarios include electricity demand from data centers*

NewERA Electricity Sector Model: U.S. Regions, Unit-Level Detail, and Fuel Supply

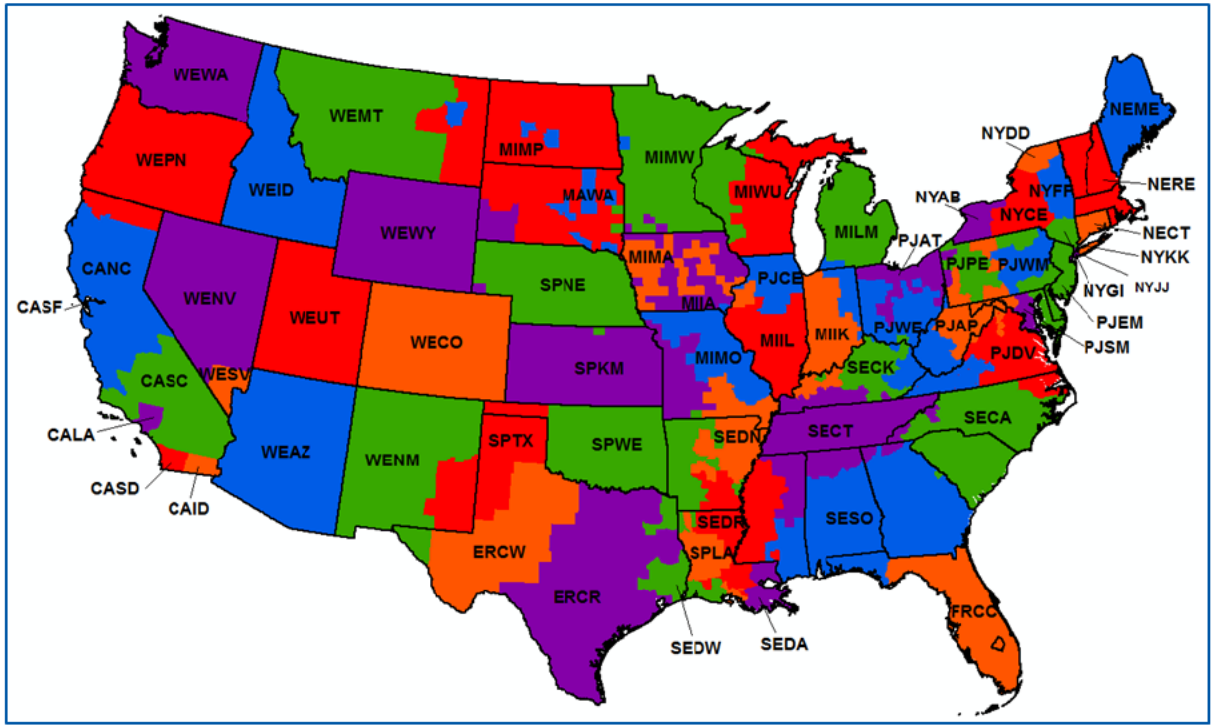
- Demand by region for 63 U.S. regions, including 11 Canadian regions (not shown in the chart). The U.S. regions include only lower-48 states.
- 25 electricity demand "load blocks"
- 10 in summer and 5 each in winter, spring, and fall
- Reflects peak vs. off-peak demand in each season
- Regional "reserve margins" based on peak demand
- Regions required to have capacity in excess of peak demand for system reliability

- Represents electricity capacity and generation at the unit level
  - 16 generating technologies, including renewables
  - Unit physical attributes: capacity, utilization, heat rate, outages, retrofits, emission rate
  - Unit costs: capital, fixed O&M, variable O&M, transmission and distribution, refurbishment
- Projects unit generation and investment decisions to minimize sector costs over projection period
  - Available actions include retirements, new builds, retrofits, coal type choice (for coal units), and fuel switching
  - Units will retire if they cannot remain profitable
  - Units can also be forced to take certain actions at specified times, or given a choice to act or retire

- Model represents supply of five fuels: coal, natural gas, oil, biomass, and uranium
- Detailed supply curves for 23 coal types
  - At each "step" on supply curve, provides price, annual production limit, and total coal reserves available at that price
  - Transportation matrix determines coals that can be delivered to each unit and the cost of delivery
  - Coal units assigned an initial coal type, but can incur a capital costs to switch to other coal types when reasonable

N$_{ew}$ERA Electricity Sector Model: Overview and Model Solution

- Bottom-up dispatch and capacity expansion model
  - Unit-level information on generating units in 63 U.S. regions
  - Detailed coal supply curves by coal type
  - Regional electricity demand and capacity requirements
- Least-cost projection of market activity
  - Satisfies demand and all other constraints over model time horizon
  - Projects unit-level generation and investment decisions and regional fuel and electricity prices
- Data sources
  - Model calibrated to U.S. Energy Information Administration's *AEO 2018*
  - Other electricity sector data from EIA, EPA, NERC, NREL, NETL, Ventyx Velocity Suite, and HellerWorx
- Required to meet many electricity market and regulatory constraints
  - Regional demand, reserve capacity requirements, fuel availability, forced retrofits, RPS or emissions regulations
  - Flexible to a variety of user-specified constraints, from unit-specific actions to market-wide regulations
- Finds the least-cost way to satisfy all constraints
  - Uses perfect foresight of market conditions
  - Chooses investments and operation of units to minimize present value of costs over the entire model period



State-Level Delivered Electricity Rate Model

- NERA's rate model uses regional model outputs from its electricity model to calculate delivered electricity sector prices.
- The regional model outputs are aggregated to the state level using a mapping of the model's regions to individual states.
- The inputs to the rate model includes wholesale, capacity and renewable energy credit (REC) prices, cost of service and electricity sales.
- The delivered electricity prices are calculated in the rate model based on the electricity market structure applicable in each state
  - In a **competitive** market, electricity prices are set through an auction process where power generators submit bids for the price, they are willing to sell electricity, and the price is set by the last generator needed to met demand at a given time
    - The delivered electricity price is based on the wholesale energy, capacity and renewable energy credit (REC) costs plus a T&D margin
      - **Wholesale** energy costs represent the costs of operating the marginal electricity generator in the electricity market region
      - **Capacity** costs represent the costs associated with ensuring enough generating capacity is available to meet both the expected peak demand plus an additional reserve margin in the electricity market region
      - **Credit** costs represent the cost of procuring RECs to meet the RPS requirements of the state(s) that are in the electricity market region

State-Level Delivered Electricity Rate Model (2)

- In a **cost-of-service (COS)** market, electricity prices are set based on the total costs to serve load
  - The delivered electricity price is based on the cost of service (operating and investment costs of the generating resources in the market region) plus a T&D margin. The cost-of-service components include the fuel costs, capital costs, fixed and variable operating and maintenance (O&M) costs, net exports and credit costs.
    - **Fuel** costs represent the delivered fuel costs for the generating resources in the electricity market region
    - **Capital** costs represent the costs to build new generating resources in the electricity market region
    - **FOM+VOM** costs represent the sum of the fixed and non-fuel variable O&M for the generating resources in the electricity market region
    - **Export** costs represent the net costs of exporting power from the electricity market region. The costs to serve load is lower with higher electricity exports as the revenue earned from exports can be used to offset fixed operating costs in the electricity market region
    - **Credit** costs represent the cost of procuring RECs to meet the RPS requirements of the state(s) that are in the electricity market region

- The T&D margin is estimated as the difference between the historical actual 2023 delivered price and the wholesale price in 2023 projected by its electricity model. The T&D margin for each ratepayer class is assumed to remain unchanged in outlooks with and without the technology-neutral tax incentives.

- For each state, the delivered price for each state (and for each future model year) is calculated assuming that it is wholly competitive and wholly COS and then these prices are weighted by the competitive/COS shares for the state.
  - For example, if a state is 95% COS, the delivered price = 95%*COS delivered price + 5%*Competitive delivered price

Technology-Neutral Tax Incentives Modeled

§45Y Production Tax Credit (PTC)

- **Base Credit:** 0.3 cents/kWh, adjusted annually for inflation.
- **Bonus Credit:** Increases to 1.5 cents/kWh if all projects meet prevailing wage and apprenticeship requirements.
- **Phaseout:** No phaseout is assumed after 2032.

§48E Investment Tax Credit (ITC)

- **Base Credit:** 6%
- **Bonus Credit:** Increases to 30% if all renewable projects meet prevailing wage and apprenticeship (PWA) requirements.
- **Additional Credits:**
    - Onshore and offshore wind projects qualifies for a 10% additional credit by meeting domestic content requirements.

Technology-Neutral Tax Incentives Modeled

Energy Type	Incentive Type	Duration	Rate	Availability
Standalone Solar	Production Tax Credit (PTC)	First 10 years of operation	1.5 cents/kWh	N/A
Solar with Storage	Production Tax Credit (PTC)	First 10 years of operation	1.5 cents/kWh	N/A
Solar Thermal	Investment Tax Credit (ITC)	N/A	30%	N/A
Onshore Wind	Production Tax Credit (PTC)	First 10 years of operation	1.5 cents/kWh	N/A
Offshore Wind	Investment Tax Credit (ITC)	N/A	40% (10% additional domestic content bonus)	N/A
Geothermal	Investment Tax Credit (ITC)	N/A	30%	Starting in the 2025 online year
Biomass	Production Tax Credit (PTC)	First 10 years of operation	1.5 cents/kWh	Starting in the 2025 online year
Hydroelectric	Investment Tax Credit (ITC)	N/A	30%	Starting in the 2025 online year
Nuclear (Existing)	Production Tax Credit (PTC)	2024 to 2032	Base Value: 0.3 cents/kWh (increased to 1.5 cents/kWh with labor	N/A
Nuclear (New)	Production Tax Credit (PTC)	N/A	Base Value: 0.3 cents/kWh (increased to 1.5 cents/kWh with labor	No phaseout after 2032

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NERA

ECONOMICS. EXPERTS. EXPERIENCE.

American Gas Association

March 5, 2025

Chairman Brett Guthrie
Ranking Member Frank Pallone
U.S. House of Representatives
Committee on Energy and Commerce
2125 Rayburn House Office Building
Washington, DC 20515

Re: House Committee on Energy and Commerce Subcommittee on Energy Hearing titled "Scaling for Growth: Meeting the Demand for Reliable, Affordable Electricity"

Dear Chairman Guthrie and Ranking Member Pallone:

The American Gas Association ("AGA") respectfully submits this letter to the Energy and Commerce Subcommittee on Energy ("Committee") to highlight the importance of the natural gas system to the reliability and resiliency of the electric system, as well as to residential, commercial, and industrial customers that directly use natural gas. This letter also provides an overview of one of AGA's reliability and resiliency efforts to meet the growing national demand for energy while maintaining affordability for consumers. More than 189 million Americans and 5.8 million businesses use natural gas because it is affordable, reliable, and safe. Importantly, on the coldest day of the year, the natural gas system delivers 3 times more energy than the electric system delivers on the hottest day of the year. The overall goal should be to preserve and enhance reliability and affordability for all customers, both gas and electric.

AGA, founded in 1918, represents more than 200 local energy companies that deliver clean natural gas throughout the United States. There are more than 79 million residential, commercial, and industrial natural gas customers in the U.S., of which 94 percent — more than 74 million customers — receive their gas from AGA members. AGA is an advocate for natural gas utility companies and their customers and provides a broad range of programs and services for member natural gas pipelines, marketers, gatherers, international natural gas companies, and industry associates. Today, natural gas meets one-third of the United States' energy needs.[1]

A resilient energy system is essential to the operation of nearly every critical function and sector of the U.S. economy as well as the communities that depend upon its services. Disruptions to the U.S. energy system have the potential to create widespread economic and social impacts, including losses in productivity, health, and safety issues, and — in the most extreme cases —

[1] For more information, please visit www.aga.org.

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loss of life. The highest priority for a natural gas local distribution company ("LDC") is the delivery of natural gas to its customers safely, reliably, responsibly, and at just and reasonable rates.[2] LDCs across the country are obligated, in accordance with applicable state law and regulatory requirements, to distribute natural gas to retail, residential, commercial, governmental, and industrial customers — including electric generators.[3] These requirements underscore the fact that residential and business customers require uninterrupted service for human need purposes, such as home heating, and business purposes.

The natural gas and electric sectors are mutually dependent on each other and over the last several years, AGA and its members have actively engaged in a variety of forums to discuss issues related to the reliability and resilience of the energy system, as well as gas-electric coordination matters. Enhancing gas-electric coordination, particularly for winter weather preparedness remains a critical priority for AGA and its members. As electricity demand is expected to increase, the electric sector will become even more dependent on natural gas and other commodities to generate electricity. In light of this, investing in appropriate energy infrastructure will be pivotal to reliably meet demand growth.

As the power system becomes more reliant on natural gas fueled generation for reliability, pipelines and storage facilities are essential to provide that service. A robust natural gas system is critical in providing gas and electric system reliability during extreme weather events. Currently, approximately 25 percent of the natural gas used for power generation is delivered by natural gas utilities; utilities use on- and off-system storage, as well as pipeline transportation, to ensure natural gas service to customers behind the city gate. As the energy system evolves, new and updated infrastructure may be required to ensure service and meet the additional demands on the system, from residential, business, industrial, and electric generation customers.

The Committee should be aware that the National Association of Regulatory Utility Commissioners ("NARUC") Gas-Electric Alignment for Reliability ("GEAR") task force was established to address the gas-electric challenges facing the energy industry today. Late last year, the GEAR task force unanimously recommended the creation of the Natural Gas Readiness Forum — an industry-led voluntary effort aimed at improving the communication, preparation, and readiness of the energy sector, via a multi-state forum of stakeholders from the various elements of the natural gas and electric value chains, as well as federal and state regulators. The GEAR working group recommended that the Natural Gas Readiness Forum be administered by AGA.

AGA convened the first Natural Gas Readiness Forum meeting on December 16 and 17, 2024 in Atlanta, Georgia. The two-day event included representatives from across the natural gas value chain including representatives from the Federal Energy Regulatory Commission,

[2] Elements of an LDC's retail services are regulated at the state level and not by the federal government. *See, e.g.,* 15 U.S.C. § 717(b) ("The provisions of this chapter . . . shall not apply . . . to the local distribution of natural gas or to the facilities used for such distribution or to the production or gathering of natural gas.").
[3] Most laws or regulations that govern utility service include the concept of the "obligation to serve." In short, this duty stems from the reality that when a franchise service territory is granted by a state or regulatory entity, a public interest is established in maintaining reliable service.

Department of Energy, North American Electric Reliability Corporation, regional transmission operators, electric generators, energy trade associations, state regulatory utility commissions and state energy offices. AGA will continue to convene such meetings to ensure preparedness of the natural gas value chain.

The American Gas Association thanks the Energy and Commerce Subcommittee on Energy for continuing discussions on reliability and its efforts to identify solutions to the challenges facing the energy industry today. AGA offers its assistance as a resource to the Committee to achieve those solutions. If you have any questions regarding this submission, please do not hesitate to contact the undersigned.

Respectfully,

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Duke NICHOLAS INSTITUTE *for* ENERGY, ENVIRONMENT & SUSTAINABILITY

Rethinking Load Growth

Assessing the Potential for Integration of Large Flexible Loads in US Power Systems

Tyler H. Norris, Tim Profeta, Dalia Patino-Echeverri, and Adam Cowie-Haskell

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INTRODUCTION

A New Era of Electricity Demand

Rapid US load growth—driven by unprecedented electricity demand from data centers, industrial manufacturing, and electrification of transportation and heating—is colliding with barriers to timely resource expansion. Protracted interconnection queues, supply chain constraints, and extended permitting processes, among other obstacles, are limiting the development of new power generation and transmission infrastructure. Against this backdrop, there is increasing urgency to identify strategies that accommodate rising demand without compromising reliability, affordability, or progress on decarbonization.

Aggregated US winter peak load is forecasted to grow by 21.5% over the next decade, rising from approximately 694 GW in 2024 to 843 GW by 2034, according to the *2024 Long-Term Reliability Assessment* of the North American Electric Reliability Corporation. This represents a 10-year compound annual growth rate (CAGR) of 2.0%, higher than any period since the 1980s (NERC 2024). Meanwhile, the Federal Energy Regulatory Commission's (FERC) latest five-year outlook forecasts 128 GW in peak load growth as early as 2029—a CAGR of 3.0% (FERC 2024b).

The primary catalyst for these updated forecasts is the surge in electricity demand from large commercial customers. While significant uncertainty remains, particularly following the release of DeepSeek, data centers are expected to account for the single largest growth segment, adding as much as 65 GW through 2029 and up to 44% of US electricity load growth through 2028 (Wilson et al. 2024; Rouch et al. 2024). Artificial intelligence (AI) workloads are projected to represent 50% to 70% of data center demand by 2030—up from less than 3% at the start of this decade—with generative AI driving 40% to 60% of this growth (Srivathsan et al. 2024; Lee et al. 2025).

Analysts have drawn parallels to the 1950s through the 1970s, when the United States achieved comparable electric power sector growth rates (Wilson et al. 2024). Yet these comparisons arguably understate the nature of today's challenge in the face of stricter permitting obstacles, higher population density, less land availability, skilled labor shortages, persistent supply chain bottlenecks, and demand for decarbonization and greater power reliability. While historical growth rates offer a useful benchmark, the sheer volume of required new generation, transmission, and distribution capacity forecasted for the United States within a condensed timeframe appears unprecedented.

The immensity of the challenge underscores the importance of deploying every available tool, especially those that can more swiftly, affordably, and sustainably integrate large loads. The time-sensitivity for solutions is amplified by the market pressure for many of these loads to interconnect as quickly as possible. In recent months, the US Secretary of Energy Advisory Board (SEAB) and the Electrical Power Research Institute (EPRI) have highlighted a key solution: load flexibility (SEAB 2024, Walton 2024a). The promise is that the unique profile of AI data centers can facilitate more flexible operations, supported by ongoing advancements in distributed energy resources (DERs).

Flexibility, in this context, refers to the ability of end-use customers to temporarily reduce their electricity consumption from the grid during periods of system stress by using on-site generators, shifting workload to other facilities, or reducing operations.[1] When system planners can reliably anticipate the availability of this load flexibility, the immediate pressure to expand generation capacity and transmission infrastructure can potentially be alleviated, mitigating or deferring costly expenditures. By facilitating near-term load growth without prematurely committing to large-scale capacity expansion, this approach offers a hedge against mounting uncertainty in the US data center market in light of the release of DeepSeek and related developments (Kearney and Hampton 2025).

Summary of Analysis and Findings

To support evaluation of potential solutions, this study presents an analysis of the existing US electrical power system's ability to accommodate new flexible loads. The analysis, which encompasses 22 of the largest balancing authorities serving 95% of the country's peak load, provides a first-order estimate of the potential for accommodating such loads with minimal capacity expansion or impact on demand-supply balance.[2]

Specifically, we estimate the gigawatts of new load that could be added in each balancing authority (BA) before total load exceeds what system planners are prepared to serve, provided the new load can be temporarily curtailed as needed. This serves as a proxy for the system's ability to integrate new load, which we term *curtailment-enabled headroom*.

Key results include (see Figure 1):

- 76 GW of new load—equivalent to 10% of the nation's current aggregate peak demand—could be integrated with an average annual load curtailment rate of 0.25% (i.e., if new loads can be curtailed for 0.25% of their maximum uptime)
- 98 GW of new load could be integrated at an average annual load curtailment rate of 0.5%, and 126 GW at a rate of 1.0%
- The number of hours during which curtailment of new loads would be necessary per year, on average, is comparable to those of existing US demand response programs
- The average duration of load curtailment (i.e., the length of time the new load is curtailed during curtailment events) would be relatively short, at 1.7 hours when average annual load curtailment is limited to 0.25%, 2.1 hours at a 0.5% limit, and 2.5 hours at a 1.0% limit
- Nearly 90% of hours during which load curtailment is required retain at least half of the new load (i.e., less than 50% curtailment of the new load is required)
- The five balancing authorities with the largest potential load integration at 0.5% annual curtailment are PJM at 18 GW, MISO at 15 GW, ERCOT at 10 GW, SPP at 10 GW, and Southern Company at 8 GW[3]

1 Note that while *curtailment* and *flexibility* are used interchangeably in this paper, *flexibility* can refer to a broader range of capabilities and services, such as the provision of down-reserves and other ancillary services.

2 For further discussion on the nuances regarding generation versus transmission capacity, see the section on limitations.

3 A complete list of abbreviations and their definitions can be found at the end of the report.

Overall, these results suggest the US power system's existing headroom, resulting from intentional planning decisions to maintain sizable reserves during infrequent peak demand events, is sufficient to accommodate significant constant new loads, provided such loads can be safely scaled back during some hours of the year. In addition, they underscore the potential for leveraging flexible load as a complement to supply-side investments, enabling growth while mitigating the need for large expenditures on new capacity.

We further demonstrate that a system's potential to serve new electricity demand without capacity expansion is determined primarily by the system's load factor (i.e., a measure of the level of use of system capacity) and grows in proportion to the flexibility of such load (i.e., what percentage of its maximal potential annual consumption can be curtailed). For this reason, in this paper we assess the technical potential for a system to serve new load under different curtailment limit scenarios (i.e., varying curtailment tolerance levels for new loads).

The analysis does not consider the technical constraints of power plants that impose intertemporal constraints on their operations (e.g., minimum downtime, minimum uptime, startup time, ramping capability, etc.) and does not account for transmission constraints. However, it ensures that the estimate of load accommodation capacity is such that total demand does not exceed the peak demand already anticipated for each season by system planners, and it discounts existing installed reserve margins capable of accommodating load that exceeds historical peaks. It also assumes that new load is constant throughout all hours.

This analysis should not be interpreted to suggest the United States can fully meet its near- and medium-term electricity demands without building new peaking capacity or expanding the grid. Rather, it highlights that flexible load strategies can help tap existing headroom to more quickly integrate new loads, reduce the cost of capacity expansion, and enable greater focus on the highest-value investments in the electric power system.

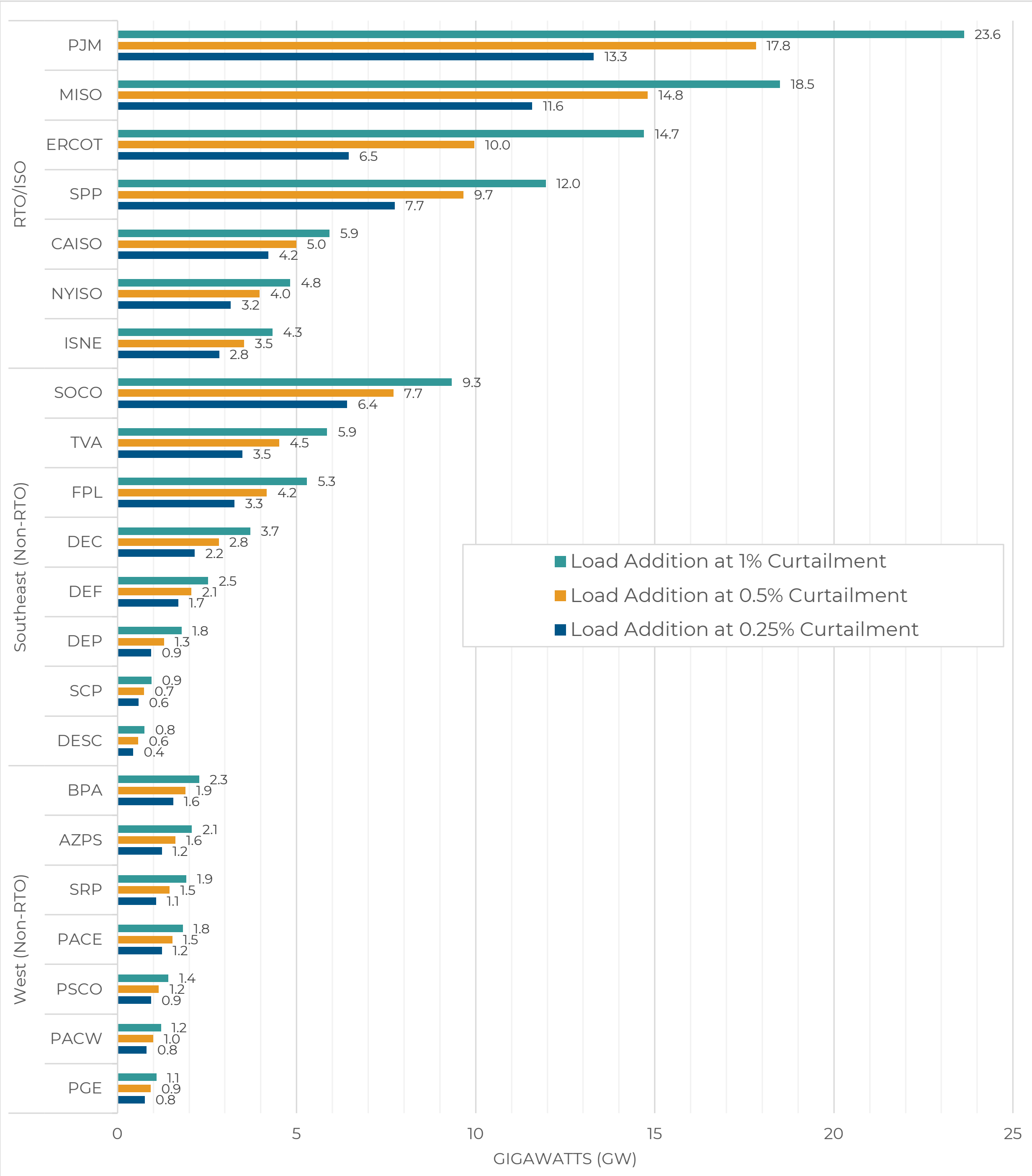
This paper proceeds as follows: the following section provides background on the opportunities and challenges to integrating large new data centers onto the grid. It explores how load flexibility can accelerate interconnection, reduce ratepayer costs through higher system utilization, and expand the role of demand response, particularly for AI-specialized data centers. We then detail the methods and results for estimating curtailment-enabled headroom, highlighting key trends and variations in system headroom and its correlation with load factors across regions. The paper concludes with a brief overview of key findings, limitations, and near-term implications.

BACKGROUND

Load Flexibility Can Accelerate Grid Interconnection

The growing demand for grid access by new large loads has significantly increased interconnection wait times, with some utilities reporting delays up to 7 to 10 years (Li et al. 2024; Saul 2024; WECC 2024). These wait times are exacerbated by increasingly severe transmission equipment supply chain constraints. In June 2024, the President's National Infrastructure Advisory Council highlighted that transformer order lead times had ballooned to two to five years—up from less than one year in 2020—while costs surged by 80% (NIAC 2024). Circuit breakers have seen similar delays: last year, the Western Area Power Administration

Figure 1. System Headroom Enabled by Load Curtailment of New Load by Balancing Authority, GW



Note: *System headroom* refers to the amount of GW by which a BA's load can be augmented every hour in the absence of capacity expansion so that, provided a certain volume of curtailment of the new load, the total demand does not exceed the supply provisioned by system planners to withstand the expected highest peak. The headroom calculation assumes the new load is constant and hence increases the total load by the same GW hour-by-hour.

reported lead times of up to four and a half years for lower voltage classes and five and a half years for higher voltage classes, alongside a 140% price hike over two years (Rohrer 2024). Wood Mackenzie reported in May 2024 that lead times for high-voltage circuit breakers reached 151 weeks in late 2023, marking a 130% year-over-year increase (Boucher 2024).

Large load interconnection delays have recently led to growing interest among data centers in colocating with existing generation facilities. At a FERC technical conference on the subject in late 2024 (FERC 2024c), several participants highlighted the potential benefits of colocation for expedited interconnection,[4] a view echoed in recent grey literature (Schatzki et al. 2024). Colocation, however, represents only a portion of load interconnections and is not viewed as a long-term, system-wide solution.

Load flexibility similarly offers a practical solution to accelerating the interconnection of large demand loads (SIP 2024, Jabeck 2023). The most time-intensive and costly infrastructure upgrades required for new interconnections are often associated with expanding the transmission system to deliver electricity during the most stressed grid conditions (Gorman et al. 2024). If a new load is assumed to require firm interconnection service and operate at 100% of its maximum electricity draw at all times, including during system-wide peaks, it is far more likely to trigger the need for significant upgrades, such as new transformers, transmission line reconductoring, circuit breakers, or other substation equipment.

To the extent a new load can temporarily reduce (i.e., curtail) its electricity consumption from the grid during these peak stress periods, however, it may be able to connect while deferring—or even avoiding—the need for certain upgrades (ERCOT 2023b). A recent study on Virginia's data center electricity load growth noted, "Flexibility in load is generally expected to offset the need for capacity additions in a system, which could help mitigate the pressure of rapid resource and transmission expansion" (K. Patel et al. 2024). The extent and frequency of required curtailment would depend on the specific nature of the upgrades; in some cases, curtailment may only be necessary if a contingency event occurs, such as an unplanned transmission line or generator outage. For loads that pay for firm interconnection service, any period requiring occasional curtailment would be temporary, ending once necessary network upgrades are completed.[5] Such "partially firm," flexible service was also highlighted by participants in FERC's 2024 technical conference on colocation.[6]

Traditionally, such arrangements have been known as *interruptible* electric service. More recently, some utilities have pursued *flexible* load interconnection options. In March 2022, for example, ERCOT implemented an interim interconnection process for large loads seeking to connect in two years or less, proposing to allow loads seeking to qualify as controllable load resources (CLRs) "to be studied as flexible and potentially interconnect more MWs" (ERCOT 2023b). More recently, ERCOT stated that "the optimal solution for grid reliability is for

4 For example, the Clean Energy Buyers Association (2024) noted, "Flexibility of co-located demand is a key asset that can enable rapid, reliable interconnection."

5 Such an arrangement is analogous to provisional interconnection service available to large generators, as defined in Section 5.9.2 of FERC's Pro Forma *Large Generator Interconnection Agreement* (LGIA).

6 MISO's market monitor representative stated, "instead of being a network firm customer, could [large flexible loads] be a non-firm, or partial non-firm [customer], and that could come with certain configuration requirements that make them truly non-firm, or partially non-firm. But, all those things are the things that could enable some loads to get on the system quicker" (FERC 2024c).

more loads to participate in economic dispatch as CLRs" (Springer 2024). Similarly, Pacific Gas and Electric (PG&E) recently introduced a Flex Connect program to allow certain loads faster access to the grid (Allsup 2024).

These options resemble interconnection services available to large generators that forgo capacity compensation, and potentially higher curtailment risk, in exchange for expedited lower-cost grid access (Norris 2023). FERC codified this approach with Energy Resource Interconnection Service (ERIS) in Order 2003 and revisited the concept during a 2024 technical workshop to explore potential improvements (Norris 2024). Some market participants have since proposed modifying ERIS to facilitate the colocation of new generators with large loads (Intersect Power 2024).

Ratepayers Benefit from Higher System Utilization

The US electric power system is characterized by a relatively low utilization rate, often referred to as the *load factor*. The load factor is the ratio of average demand to peak demand over a given period and provides a measure of the utilization of system capacity (Cerna et al. 2023). A system with a high load factor operates closer to its peak system load for more hours throughout the year, while a system with a low load factor generally experiences demand spikes that are higher than its typical demand levels (Cerna et al. 2022). This discrepancy means that, for much of the year, a significant portion of a system's available generation and transmission infrastructure is underutilized (Cochran et al. 2015).

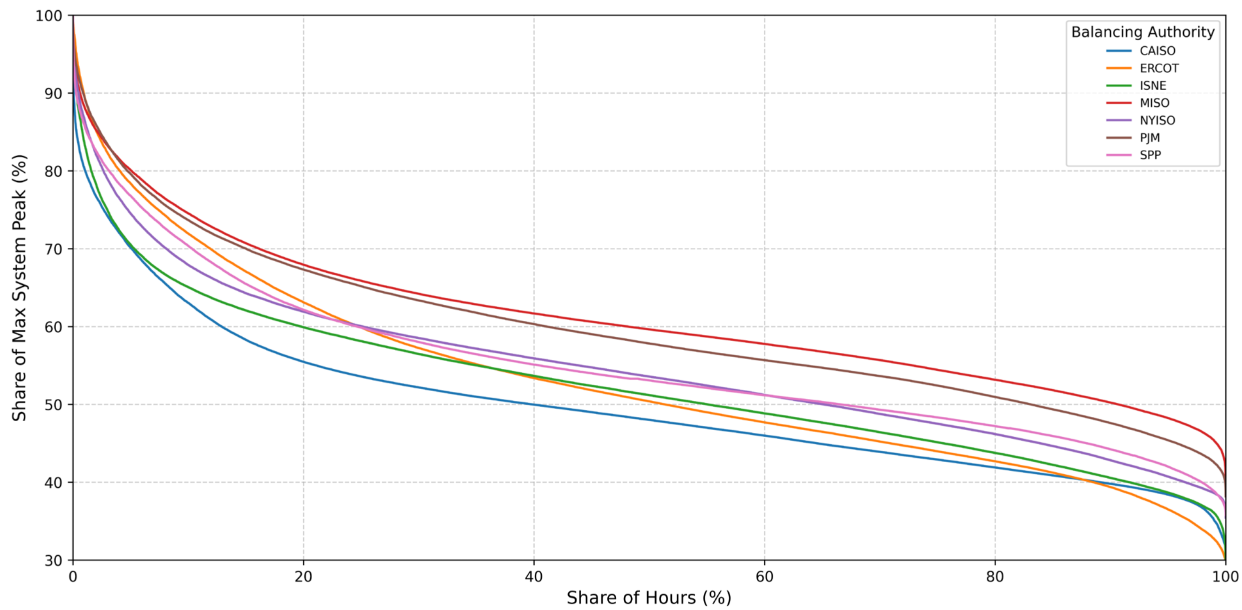
The power system is designed to handle the highest demand peaks, which in some cases may occur less than once per year, on average, due to extreme weather events. As a result, the bulk of the year sees demand levels well below that peak, leaving substantial headroom in installed capacity. Seasonal shifts add another layer of complexity: some balancing authorities may show higher load factors in summer, yet experience significantly lower utilization in winter, and vice versa.

The *load duration curve* (LDC) illustrates system utilization by ranking demand from highest to lowest over a given period. It provides a visual representation of how often certain demand levels occur, highlighting the frequency and magnitude of peak demand relative to average load. A steep LDC suggests high demand variability, with peaks significantly exceeding typical loads, while a flatter LDC indicates more consistent usage. Figure 2 presents LDCs for each US RTO/ISO based on hourly load between 2016 and 2024, standardized as a percentage of each system's maximum peak demand to allow cross-market comparisons.

A system utilization rate below 100% is expected for most large-scale infrastructure designed to withstand occasional surges in demand. Nevertheless, when the gap between average demand and peak demand is consistently large, it implies that substantial portions of the electric power system—generation assets, transmission infrastructure, and distribution networks—remain idle for much of the year (Riu et al. 2024). These assets are expensive to build and maintain, and ratepayers ultimately bear the cost.

Once the infrastructure is in place, however, there is a strong economic incentive to increase usage and spread these fixed costs over more kilowatt-hours of delivered electricity. An important consideration is therefore the potential for additional load to be added without significant new investment, provided the additional load does not raise the system's overall

Figure 2. Load Duration Curve for US RTO/ISOs, 2016–2024



This figure is adapted from the analysis section of this paper, which contains additional detail on the data and method.

peak demand and thereby trigger system expansion.[7] When new loads are flexible enough to avoid a high coincident load factor, thereby mitigating contribution to the highest-demand hours, they fit within the existing grid's headroom.[8] By strategically timing or curtailing demand, these flexible loads can minimize their impact on peak periods. In doing so, they help existing customers by improving the overall utilization rate—thereby lowering the per-unit cost of electricity—and reduce the likelihood that expensive new peaking plants or network expansions may be needed.

In contrast, inflexible new loads that increase the system's absolute peak demand can drive substantial additional needs for generation and transmission capacity. Even a modest rise in peak demand may trigger capital investments in peaking plants, fuel supply infrastructure, and reliability enhancements. These cost implications have contributed to increasingly contentious disputes in which regulators or ratepayer advocates seek to create mechanisms to pass the costs of serving large loads directly to those loads and otherwise ensure data centers do not shift costs via longer contract commitments, billing minimums, and upfront investment (Howland 2024a; Riu et al. 2024). Some examples include:

- The **Georgia Public Service Commission (GPSC)**, citing "staggering" large load growth and the need to protect ratepayers from the costs of serving those customers, recently implemented changes to customer contract provisions if peak draw exceeds 100 MW, mandating a GPSC review and allowing the utility to seek longer contracts and minimum billing for cost recovery (GPSC 2025). This follows GPSC's approval

7 See the discussion on limitations and further analysis in the following section for additional nuance.

8 Demand charges are often based on coincident consumption (e.g., ERCOT's Four Coincident Peak charge uses the load's coincident consumption at the system's expected seasonal peak to determine an averaged demand charge that may account for >30% of a user's annual bill).

of 1.4 GW of gas capacity proposed by Georgia Power in response to load growth "approximately 17 times greater than previously forecasted" through 2030/2031, a forecast it revised upward in late 2024 (GPC 2023, 2024).

- **Ohio**, where American Electric Power issued a moratorium on data center service requests, followed by a settlement agreement with the Public Service Commission staff and consumer advocates that calls for longer contract terms, load ramping schedules, a minimum demand charge, and collateral for service from data centers exceeding 25 MW (Ohio Power Company 2024).
- **Indiana**, where 4.4 GW of interconnection requests from a "handful" of data centers represents a 157% increase in peak load for Indiana Michigan Power over the next six years. Stakeholders there have proposed "firewalling" the associated cost of service from the rest of the rate base, wherein the utility would procure a separate energy, capacity, and ancillary resource portfolio for large loads and recover that portfolio's costs from only the qualifying large loads (Inskeep 2024).
- **Illinois**, where Commonwealth Edison reported that large loads have paid 8.2% of their interconnection costs while the remaining 91.8% is socialized across general customers (ComEd 2024).

These examples underscore the significance of exploring how flexible loads can mitigate peak increases, optimize the utilization of existing infrastructure, and reduce the urgency for costly and time-consuming capacity expansions.

Demand Response and Data Centers

Demand response refers to changes in electricity usage by end-use customers to provide grid services in response to economic signals, reliability events, or other conditions. Originally developed to reduce peak loads (also called *peak shaving*), demand response programs have evolved to encompass a variety of grid services, including balancing services, ancillary services, targeted deferral of grid upgrades, and even variable renewable integration (Hurley et al. 2013; Ruggles et al. 2021). Demand response is often referred to as a form of *demand-side management* or *demand flexibility* (Nethercutt 2023).

Demand response is the largest and most established form of virtual power plant (Downing et al. 2023), with 33 GW of registered capacity in wholesale RTO/ISO programs and 31 GW in retail programs as of 2023 (FERC 2024a).[9] As a share of peak demand, participation in RTO/ISO programs ranges from a high of 10.1% in MISO to a low of 1.4% in SPP. A majority of enrolled capacity in demand response programs are industrial or commercial customers, representing nearly 70% of registered capacity in retail (EIA 2024).

Following a decade of expansion, growth in demand response program participation stalled in the mid-2010s partially because of depressed capacity prices, forecasted over-capacity, and increasingly restrictive wholesale market participation rules (Hledik et al. 2019). However, the resurgence of load growth and increasing capacity prices, coupled with ongoing advancements in DERs and grid information and communication technologies (ICT) appears likely to reverse this trend.

9 RTO/ISO and retail data may overlap.

Studies of national demand response potential have identified a range of potential scenarios (Becker et al. 2024), ranging as high as 200 GW by 2030 in a 2019 study, comprising 20% of the then-forecasted system peak and yielding $15 billion in annual benefits primarily via avoided generation and transmission and distribution (T&D) capacity (Hledik et al. 2019). Notably, this research was conducted before recent load growth forecasts.

The Participation Gap: Data Centers and Demand Response

For nearly two decades, computational loads—and data centers in particular—have been identified as a promising area for demand response. Early studies explored these capabilities, such as a two-phase Lawrence Berkeley National Laboratory study drawing on six years of research, which concluded in 2010 that "data centers, on the basis of their operational characteristics and energy use, have significant potential for demand response" (Ghatikar et al. 2010) and in 2012 that "[certain] data centers can participate in demand response programs with no impact to operations or service-level agreements" (Ghatikar et al. 2012). The 2012 study provided one of the earliest demonstrations of computational load responsiveness, finding that 10% load shed can typically occur within 6 to 15 minutes.

Despite this promise, data centers have historically exhibited low participation rates in demand response programs as a result of operational priorities and economic incentives (Basmadjian 2019; Clausen et al. 2019; Wierman et al. 2014). Data centers are designed to provide reliable, uninterrupted service and generally operate under service-level agreements (SLAs) that mandate specific performance benchmarks, including uptime, latency, and overall quality of service. Deviation from these standards can result in financial penalties and reputational harm, creating a high-stakes environment where operators are averse to operational changes that introduce uncertainty or risk (Basmadjian et al. 2018).

Compounding this challenge is the increasing prevalence of large-scale colocated data centers, which represent a significant share of the data center market (Shehabi et al. 2024). These facilities house multiple tenants, each with varying operational requirements. Coordinating demand response participation in such environments introduces layers of administrative and logistical complexity, as operators must mediate cost- and reward-sharing agreements among tenants. Further, while data centers possess significant technical capabilities, tapping these capabilities for demand response requires sophisticated planning and expertise, which some operators may not have needed to date (Silva et al. 2024).

Economic considerations have further compounded this reluctance. Implementing a demand response program requires investments in advanced energy management systems, staff training, and integration with utility platforms for which costs can be material, particularly for smaller or midsized facilities. At the same time, financial incentives provided by most demand response programs have historically been modest and insufficient to offset the expenses and opportunity costs associated with curtailed operations. For operators focused on maintaining high utilization rates and controlling costs, the economic proposition of demand response participation may be unattractive.

Existing demand response program designs may inadvertently discourage participation. Many programs were originally created with traditional industrial consumers in mind, with different incentives and operational specifications. Price-based programs may require high price variability to elicit meaningful responses, while direct control programs without sufficient guardrails may introduce unacceptable risks related to uptime and performance. The complexity of active participation in demand response markets, including bidding processes and navigating market mechanisms, adds another layer of difficulty. Without streamlined participation structures, tailored incentives, and metrics that reflect the scale and responsiveness of data centers, many existing demand response programs may be ill-suited to the operational realities of modern data centers.

Table 1. Key Data Center Terms

Term	Definition
AI workload	A broad category encompassing computational tasks related to machine learning, natural language processing, generative AI, deep learning, and other AI-driven applications.
AI-specialized data center	Typically developed by hyperscalers, this type of facility is optimized for AI workloads and relies heavily on high-performance graphics processing units (GPUs) and advanced central processing units (CPUs) to handle intensive computing demands.
Computational load	A category of electrical demand primarily driven by computing and data processing activities, ranging from general-purpose computing to specialized AI model training, cryptographic processing, and high-performance computing (HPC).
Conventional data center	A facility that could range from a small enterprise-run server room to a large-scale cloud data center that handles diverse non-AI workloads, including file sharing, transaction processing, and application hosting. These facilities are predominantly powered by CPUs.
Conventional workload	A diverse array of computing tasks typically handled by CPUs, including file sharing, transaction processing, application hosting, and similar operations.
Cryptomine	A dedicated server farm optimized for high-throughput operations on blockchain networks, typically focused on validating and generating cryptocurrency.
Hyperscalers/hyperscale data centers	Large, well-capitalized cloud service providers that build hyperscale data centers to achieve scalability and high performance at multihundred megawatt scale or larger (Howland 2024b, Miller 2024).
Inferencing	The ongoing application of an AI model, where users prompt the model to provide responses or outputs. According to EPRI, inferencing represents 60% of an AI model's annual energy consumption (Aljbour and Wilson 2024).
Model training	The process of developing and training AI models by processing vast amounts of data. Model training accounts for 30–40% of annual AI power consumption and can take weeks or months to complete (Aljbour and Wilson 2024).

Rethinking Data Centers with AI-Driven Flexibility

Limited documentation of commercial data center participation in demand response has reinforced a perception that these facilities' demands are inherently inflexible loads. A variety of recent developments in computational load profiles, operational capabilities, and broader market conditions, however, suggest that a new phase of opportunity and necessity is emerging.

In a July 2024 memo on data center electricity demand, the SEAB recommended the Department of Energy prioritize initiatives to characterize and advance data center load flexibility, including the development of a "flexibility taxonomy and framework that explores the financial incentives and policy changes needed to drive flexible operation" (SEAB 2024). Building on these recommendations, EPRI announced a multi-year Data Center Flexible Load Initiative (DCFlex) in October 2024 with an objective "to spark change through hands-on and experiential demonstrations that showcase the full potential of data center operational flexibility and facility asset utilization," in partnership with multiple tech companies, electric utilities, and independent system operators (Walton 2024a).[10]

The central hypothesis is that the evolving computational load profiles of AI-specialized data centers facilitate operational capabilities that are more amendable to load flexibility. Unlike the many real-time processing demands typical of conventional data center workloads, such as cloud services and enterprise applications, the training of neural networks that power large language models and other machine learning algorithms is deferrable. This flexibility in timing, often referred to as *temporal flexibility*, allows for the strategic scheduling of training as well as other delay-tolerant tasks, both AI and non-AI alike. These delay-tolerant tasks are also referred to as *batch processing* and are typically not user-prompted (AWS 2025).

This temporal flexibility complements the developing interest in *spatial flexibility*, the ability to dynamically distribute workloads across one or multiple data centers in different geographic locations, optimizing resource utilization and operational efficiency. As stated by EPRI in a May 2024 report, "optimizing data center computation and geographic location to respond to electricity supply conditions, electricity carbon intensity, and other factors in addition to minimizing latency enables data centers to actively adjust their electricity consumption … some could achieve significant cost savings—as much as 15%—by optimizing computation to capitalize on lower electric rates during off-peak hours, reducing strain on the grid during high-demand periods" (EPRI 2024). For instance, having already developed a temporal workload shifting system, Google is seeking to implement spatial flexibility as well (Radovanović 2020).

In addition to temporal and spatial flexibility, other temporary load reduction methods may also enable data center flexibility. One approach is dynamic voltage and frequency scaling, which reduces server power consumption by lowering voltage or frequency at the expense of processing speed (Moons et al. 2017; Basmadjian 2019; Basmadjian and de Meer 2018). Another is server optimization, which consolidates workloads onto fewer servers while idling or shutting down underutilized ones, thereby reducing energy waste (Basmajian 2019; Chaurasia et al. 2021). These load reduction methods are driven by advances in virtual workload management, made possible by the "virtualization" of hardware (Pantazoglou et al. 2016).

10 Pointing to EPRI's new DCFlex Initiative, Michael Liebreich noted in a recent essay, "For instance, when they see how much it costs to work 24/7 at full power, perhaps data-center owners will see a benefit to providing some demand response capacity… " (Liebreich 2024).

Finally, temperature flexibility leverages the fact that cooling systems account for 30% to 40% of data center energy consumption (EPRI 2024). For instance, operators can increase cooling during midday when solar energy is abundant and reduce cooling during peak evening demand.[11] While these methods may be perceived as uneconomic due to potential impacts on performance, hardware lifespan, or SLAs, they are not intended for continuous use. Instead, they are best suited for deployment during critical hours when grid demand reduction is most valuable.

Beyond peak shaving, data centers also hold potential to participate in ancillary services, particularly those requiring rapid response, such as frequency regulation. Studies have described how data centers can dynamically adjust workloads to provide real-time support to the grid, effectively acting as "virtual spinning reserves" that help stabilize grid frequency and integrate intermittent renewable resources (McClurg et al. 2016; Al Kez et al. 2021; Wang et al. 2019). This capability extends beyond traditional demand response by providing near-instantaneous balancing resources (Zhang et al. 2022).

Three overarching market trends create further opportunities for load flexibility now than in the past. The first is constrained supply-side market conditions that raise costs and lead times for the interconnecting large inflexible loads, when speed to market is paramount for AI developers. The second is advancements in on-site generation and storage technologies that have lowered costs and expanded the availability of cleaner and more commercially viable behind-the-meter solutions, increasing their appeal to data center operators (Baumann et al. 2020). The third is the growing concentration of computational load in colocated or hyper-scale data centers—accounting for roughly 80% of the market in 2023—which is lending scale and specialization to more sophisticated data center operators. These operators, seek-ing speed to market, may be more likely to adopt flexibility in return for faster interconnec-tion (Shehabi et al. 2024; Basmadjian et al. 2018). The overarching trends underpinning this thesis are summarized in Table 2.

An important consideration for future data center load profiles is the balance between AI-specialized data centers focused on model development and those oriented toward inferencing. If fewer AI models are developed, a larger proportion of computing resources will shift toward inferencing tasks, which is delay-intolerant and variable (Riu et al. 2024). According to EPRI, training an AI model accounts for 30% of its annual footprint, compared to 60% for inferencing the same model (EPRI 2024).

In the absence of regulatory guidance, most advancements in data center flexibility to date are being driven by voluntary private-sector initiatives. Some hyperscalers and data center developers are taking steps to mitigate grid constraints by prioritizing near-term solutions for load flexibility. For example, one such company, Verrus, has established its business model around the premise that flexible data center operations offer an effective solution for growth needs (SIP 2024). Table 3 highlights additional initiatives related to facilitating or demonstrating data center flexibility.

11 Cooling demand for servers is inherently dependent on server workloads. Therefore, reducing workloads saves on cooling needs as well.

Table 2. Trends Enabling Data Center Load Flexibility

Category	Legacy	Future
Computational load profile	• Conventional servers with CPU-dominated workloads (Shehabi et al. 2024) • Real-time, delay-intolerant, and unscheduled processing (e.g., cloud services, enterprise apps) • Low latency critical	• AI-specialized servers with GPU or tensor processing unit (TPU)-favored workloads (Shehabi et al. 2024) • Greater portion of delay-tolerant and scheduled machine learning workloads (model training, non-interactive services) • Higher share of model training affords greater demand predictability • Highly parallelized workloads (Shehabi et al. 2024)
Operational capabilities	• Minimal temporal load shifting • Minimal spatial load migration • High proximity to end users for latency-sensitive tasks • Reliance on Tier 2 diesel generators for backup • Limited utilization of on-site power resulting from pollution concerns and regulatory restrictions (Cary 2023)	• More robust and intelligent temporal workload shifting (Radovanović et al. 2022) • Advanced spatial load migration and multi–data center training (D. Patel et al. 2024) • Flexibility in location for model training • Backup power diversified (storage, renewables, natural gas, cleaner diesel) • Cleaner on-site power enables greater utilization
Market conditions	• Minimal electric load growth • High availability of T&D network headroom • Standard interconnection timelines and queue volumes • Low supply chain bottlenecks for T&D equipment • Low capacity prices and forecasted overcapacity • High cost of clean on-site power options • Small-scale “server room” model	• High electric load growth • Low availability of T&D network headroom • Long interconnection timelines and overloaded queues • High supply chain bottlenecks for T&D equipment • High capacity prices and forecasted undercapacity (Walton 2024b) • Lower cost of clean on-site power options (Baranko et al. 2024) • Data center operations concentrating in large-scale facilities and operators

Table 3. Implementations of Computational Load Flexibility

Category	Examples
Operational flexibility	• Google deployed a "carbon-aware" temporal workload–shifting algorithm and is now seeking to develop geographic distribution capabilities (Radovanović 2020). • Google data centers have participated in demand response by reducing non-urgent compute tasks during grid stress events in Oregon, Nebraska, the US Southeast, Europe, and Taiwan (Mehra and Hasegawa 2023). • Enel X has supported demand response participation by data centers in North America, Ireland, Australia, South Korea, and Japan, including use of on-site batteries and generators to enable islanding within minutes (Enel X 2024). • Startup companies like Emerald AI are developing software to enable large-scale demand response from data centers through recent advances in computational resource management to precisely deliver grid services while preserving acceptable quality of service for compute users
On-site power	• Enchanted Rock, an energy solutions provider that supported Microsoft in building a renewable natural gas plant for a data center in San Jose, CA, created a behind-the-meter solution called Bridge-to-Grid, which seeks to provide intermediate power until primary service can be switched to the utility. At that point, the on-site power transitions to flexible backup power (Enchanted Rock 2024, 2025).
Market design and utility programs	• ERCOT established the Large Flexible Load Task Force and began to require the registration of large, interruptible loads seeking to interconnect with ERCOT for better visibility into their energy demand over the next five years (Hodge 2024). • ERCOT's demand response program shows promise for data center flexibility, with 750+ MW of data mining load registered as CLRs, which are dispatched by ERCOT within preset conditions (ERCOT 2023a). • PG&E debuted Flex Connect, a pilot that provides quicker interconnection service to large loads in return for flexibility at the margin when the system is constrained (Allsup 2024, St. John 2024).
Cryptomining	• A company generated more revenue from its demand response participation in ERCOT than from Bitcoin mining in one month, at times accommodating a 95% load reduction during peak demands (Riot Platforms 2023).

ANALYSIS OF CURTAILMENT-ENABLED HEADROOM

In this section we describe the method for estimating the gigawatts of new load that could be added to existing US power system load before the total exceeds what system planers are prepared to serve, provided that load curtailment is applied as needed. This serves as a proxy for the system's ability to integrate new load, which we term *curtailment-enabled headroom*.[12] We first investigated the aggregate and seasonal load factor for each of the 22 investigated balancing authorities, which measures a system's average utilization rate. Second, we computed the curtailment-enabled headroom for different assumptions of ac-

12 SEAB proposed a similar term, *available flex capacity*, in its July 2024 report *Recommendations on Powering Artificial Intelligence and Data Center Infrastructure*.

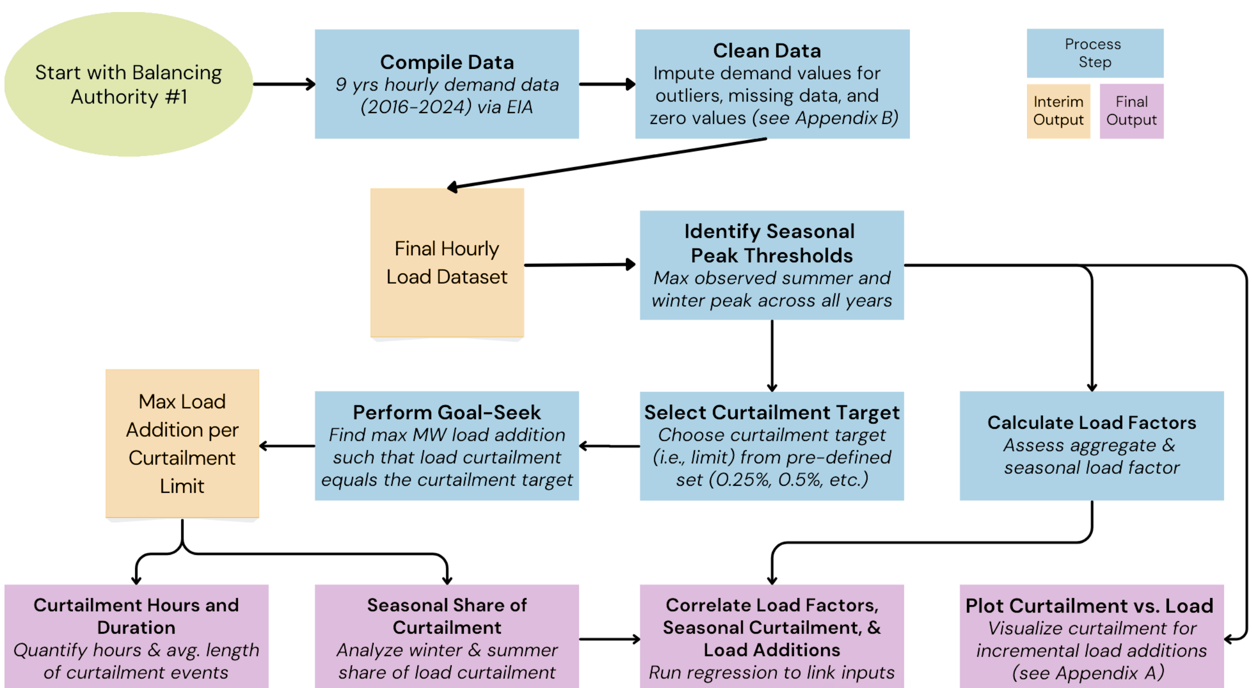
ceptable new load curtailment rates. In this context, *curtailment* refers to instances where the new load temporarily reduces its electricity draw—such as by using on-site generation resources, shifting load temporally or spatially, or otherwise reducing operations—to ensure system demand does not exceed historical peak thresholds. Third, we quantified the magnitude, duration, and seasonal concentration of the load curtailment for each balancing authority. Finally, we examined the correlation between load factor, seasonal curtailment, and max potential load additions. This process is summarized in Figure 3.

Data and Method

Data

We considered nine years of hourly load data aggregated for each of the 22 balancing authorities, encompassing seven RTO/ISOs,[13] eight non-RTO Southeastern BAs,[14] and seven non-RTO Western BAs.[15] Together, these balancing authorities represent 744 of the approximate 777 GW of summer peak load (95%) across the continental United States. The dataset, sourced from the EIA Hourly Load Monitor (EIA-930), contains one demand value per hour

Figure 3. Steps for Calculating Headroom and Related Metrics



13 CAISO, ERCOT, ISO-NE, MISO, NYISO, PJM, and SPP.

14 DEC; DEP; DEF; DESC; FPL; Santee Cooper, SCP; Southern Company (SOCO); and TVA. Note the different BA codes used by EIA: DUK for DEC, CPLE for DEP, SCEG for DESC, FPC for DEF, and SC for SCP. Also note that Southern Company includes Georgia Power, Alabama Power, and Mississippi Power. A complete list of abbreviations and their definitions can be found at the end of the paper.

15 AZPS, BPA, PACE, PACW, PGE, PSCO, and SRP. Note that EIA uses the code BPAT for BPA. A complete list of abbreviations and their definitions can be found at the end of the paper.

and spans January 1, 2016, through December 31, 2024.[16] Data from 2015 were excluded because of incomplete reporting.[17] The dataset was cleaned to identify and impute values for samples with missing or outlier demand values (see details in Appendix B).

Determining Load Additions for Curtailment Limits

An analysis was conducted to determine the maximum load addition for each balancing authority that can be integrated while staying within predefined curtailment limits applied to the new load. The load curtailment limits (0.25%, 0.5%, 1.0%, and 5.0%) were selected within the range of maximum curtailment caps for existing interruptible demand response programs.[18] The analysis focused on finding the load addition volume in megawatts that results in an average annual load curtailment rate per balancing authority that matches the specified limit. To achieve this, a goal-seek technique was used to solve for the load addition that satisfies this condition,[19] for which the mathematical expression is presented in Appendix C. The calculation assumed the new load is constant and hence increases the total system load by the same gigawatt volume hour-by-hour. To complement this analysis and visualize the relationship between load addition volume and curtailment, curtailment rates were also calculated across small incremental load additions (i.e., 0.25% of the BA's peak load).

Load Curtailment Definition and Calculation

Load curtailment is defined as the megawatt-hour reduction of load required to prevent the augmented system demand (existing load + new load) from exceeding the maximum seasonal system peak threshold (e.g., see Figure 4). Curtailment was calculated hourly as the difference between the augmented demand and the seasonal peak threshold. These hourly curtailments in megawatt-hours were aggregated for all hours in a year to determine the total annual curtailment. The curtailment rate for each load increment was defined as the total annual curtailed megawatt-hours divided by the new load's maximum potential annual consumption, assuming continuous operation at full capacity.

Peak Thresholds and Seasonal Differentiation

Balancing authorities develop resource expansion plans to support different peak loads in winter and summer. To account for variation, we defined seasonal peak thresholds for each balancing authority. Specifically, we identified the maximum summer peak and the maximum winter peak observed from 2016 to 2024 for each balancing authority.[20] These thresholds serve as the upper limits for system demand during their respective seasons, and all

16 Additional detail on EIA's hourly load data collection is available at https://www.eia.gov/electricity/gridmonitor/about.

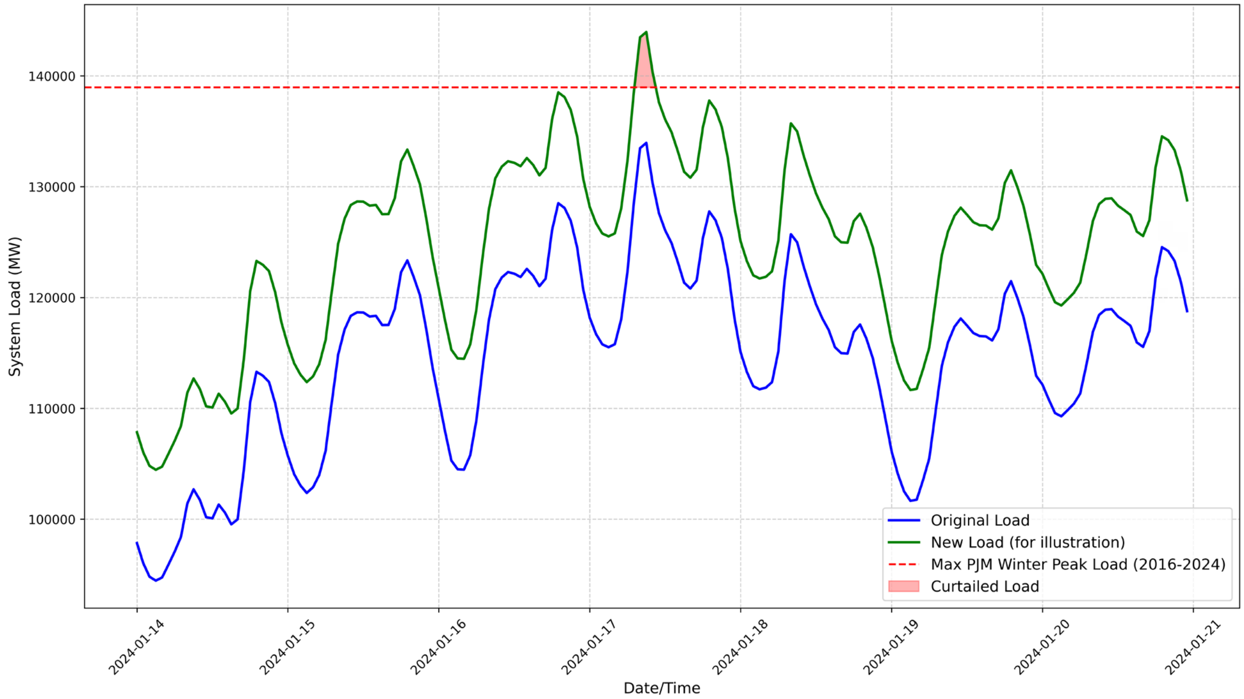
17 Fewer than half of the year's load hours were available, making the data unsuitable for inclusion.

18 For example, PG&E's and Southern California Edison's Base Interruptible Programs limit annual interruption for registered customers to a maximum of 180 hours (2.0% of all annual hours) or 10 events per month.

19 The goal-seek approach was implemented using Python's scipy.optimize.root_scalar function from the SciPy library. This tool is designed for solving one-dimensional root-finding problems, where the goal is to determine the input value that satisfies a specified equation within a defined range.

20 To identify the max seasonal peak load, summer was defined as June–August, while winter encompassed December–February. In a few cases, the BA's seasonal peak occurred within one month of these periods (AZPS winter, FPL winter, CAISO summer, CAISO winter), which were used as their max seasonal peak. To account for potential (albeit less likely) curtailment in shoulder months, the applicable summer peak was applied to April–May and September–October and the winter peak to November and March.

Figure 4. Illustrative Load Flexibility in PJM



megawatt-hours that exceeded these thresholds was counted as curtailed energy. This seasonal differentiation captures the distinct demand characteristics of regions dominated by cooling loads (summer peaks) versus heating loads (winter peaks).

Year-by-Year Curtailment Analysis

Curtailment was analyzed independently for each year from 2016 to 2024. This year-by-year approach captures temporal variability in demand patterns, including the effects of extreme weather events and economic conditions. For each year, curtailment volumes were calculated across all load addition increments, resulting in a list of annual curtailment rates corresponding to each load increment. To synthesize results across years, we calculated the average curtailment rate for each load addition increment by averaging annual curtailment rates over the nine years. This averaging process smooths out year-specific anomalies and provides an estimate of the typical system response to additional load. This analysis was also used to calculate the average number of hours of curtailment for each curtailment limit and the seasonal allocation of curtailed generation.[21] We also assessed the magnitude of load curtailment required during these hours as a share of the new load's maximum potential draw to calculate the number of hours when 90%, 75%, and 50% or more of the load would still be available.

21 Consistent with the curtailment analysis, summer was defined as June–August and winter as December–February. For BAs located on the Pacific coast (BPA, CAISO, PGE, PACE, PACW), November was counted as winter given the region's unique seasonal load profile.

Figure 5. Load Factor by Balancing Authority and Season, 2016–2024

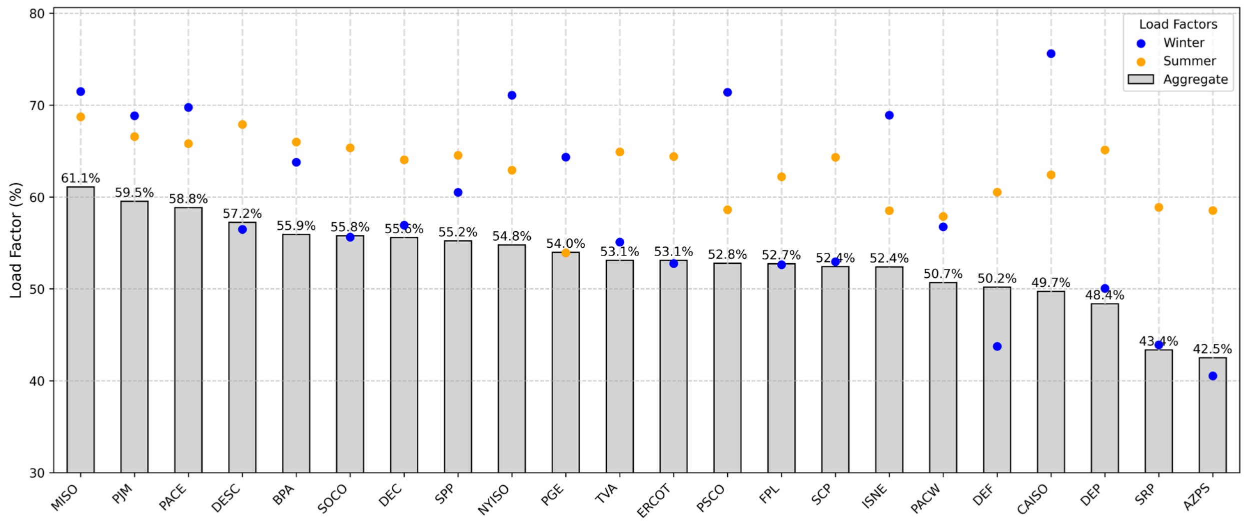
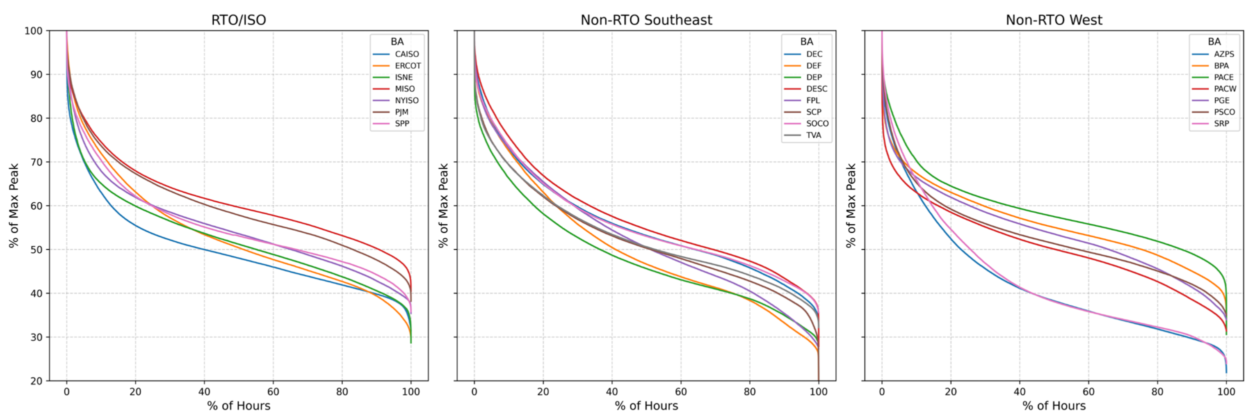


Figure 6. Load Duration Curves by Balancing Authority, 2016–2024



Results

Load Factor

In examining data for 22 balancing authorities, we found that aggregate load factors ranged between 43% to 61% (Figures 5 and 6), with an average and median value of 53%. The BAs with the lowest aggregate load factors were those in the desert southwest, Arizona Public Service Company (AZPS) and Salt River Project Agricultural Improvement and Power District (SRP). In terms of seasonal load factor, defined here as the average seasonal load as a share of seasonal maximum load (i.e., not as a share of the maximum all-time system load), winter load factors were notably lower than summer. The average and median winter load factor was 59% and 57% respectively, compared to 63% and 64% for summer. A majority of the balancing authorities had higher summer load factors (14) than winter (8).

Headroom Volume

Results show that the headroom across the 22 analyzed balancing authorities is between 76 to 215 GW, depending on the applicable load curtailment limit. This means that 76 to 215 GW of load could be added to the US power system and yet the total cumulative load would remain below the historical peak load, except for a limited number of hours per year

Figure 7. Headroom Enabled by Load Curtailment Thresholds, GW

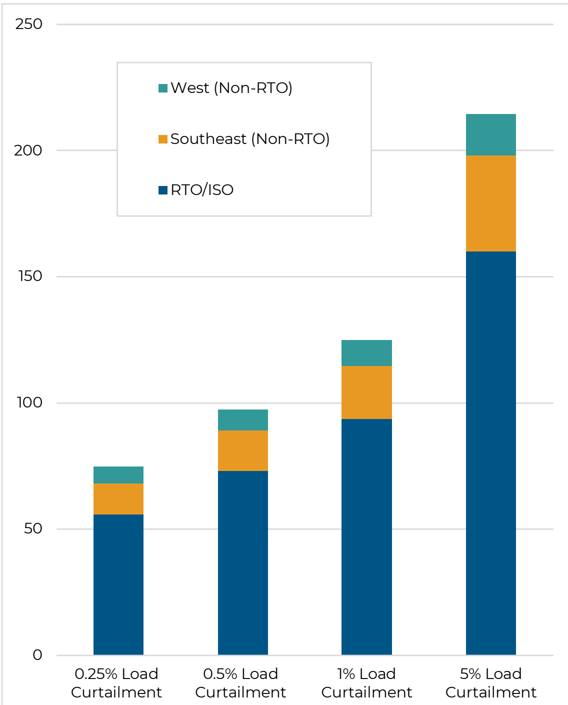


Figure 8. Headroom Enabled by 0.5% Load Curtailment by Balancing Authority, GW

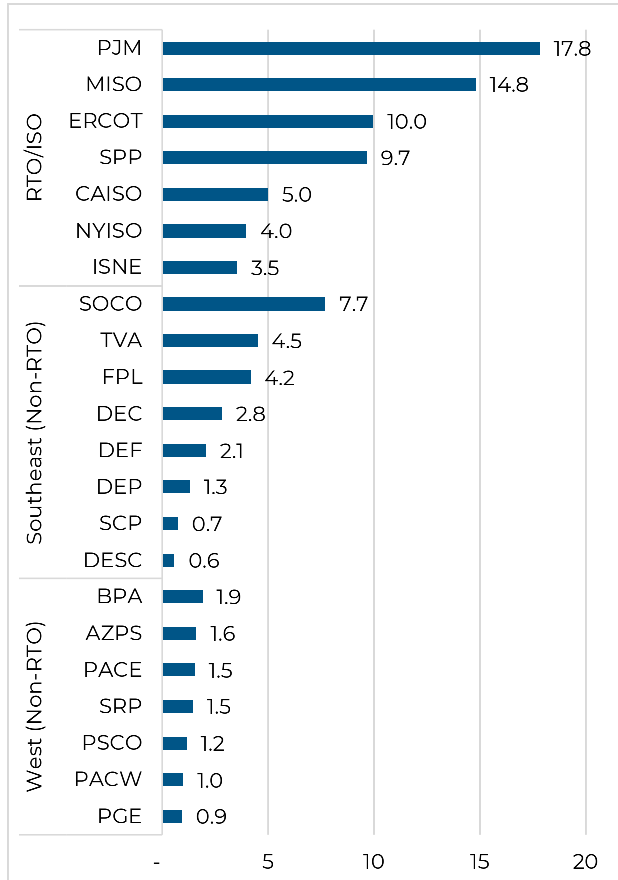
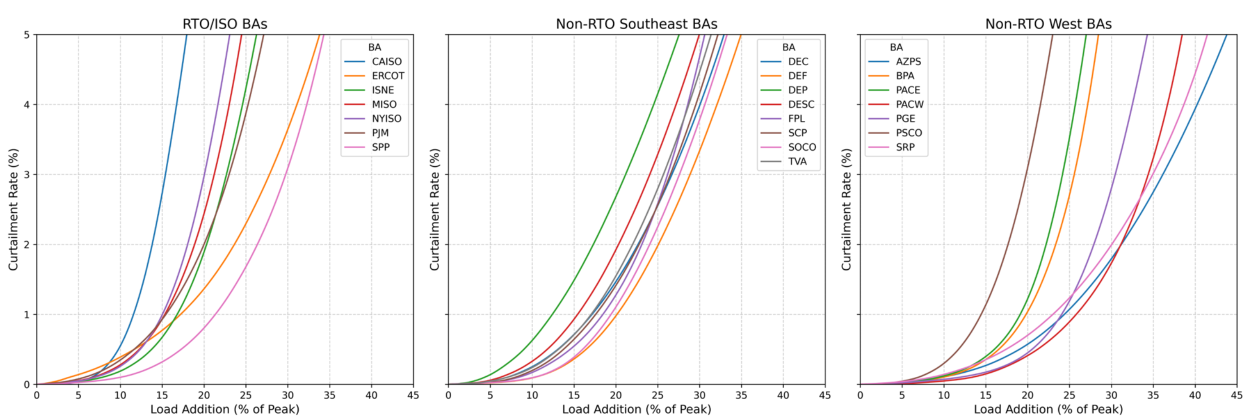


Figure 9. Load Curtailment Rate Due to Load Addition, % of System Peak



when the new load would be unserved. Specifically, 76 GW of headroom is available at an expected load curtailment rate of 0.25% (i.e., if 0.25% of the maximum potential annual energy consumption of the new load is curtailed during the highest load hours, or 1,643 out of 657,000 GWh). This headroom increases to 98 GW at 0.5% curtailment, 126 GW at 1.0% curtailment, and 215 GW at 5.0% curtailment (Figure 7). Headroom varies by balancing authority (Figure 8), including as a share of system peak (Figure 9). The five balancing authorities with the highest potential volume at 0.5% annual curtailment are PJM at 18 GW, MISO at 15 GW, ERCOT at 10 GW, SPP at 10 GW, and Southern Company at 8 GW. Detailed plots for each balancing authority, including results for each year, can be found in Appendix A.

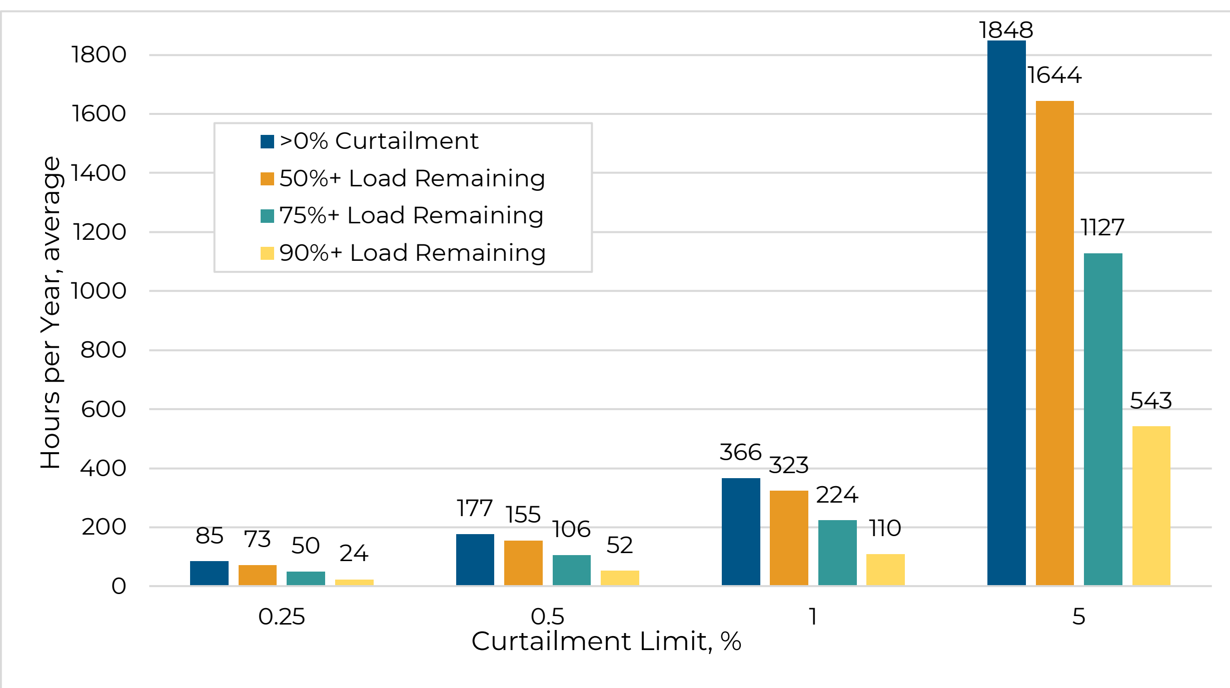
Curtailment Hours

A large majority of curtailment hours retain most of the new load. Most hours during which load reduction is required entail a curtailment rate below 50% of the new load. Across all 22 BAs, the average required load curtailment times are 85 hours under the 0.25% curtailment rate (~1% of the hours in a year), 177 hours under the 0.5% curtailment rate, 366 hours under the 1.0% curtailment rate, and 1,848 hours under the 5.0% curtailment rate (i.e., ~21% of the hours). On average, 88% of these hours retain at least 50% of the new load (i.e., less than 50% curtailment of the load is required), 60% of the hours retain at least 75% of the load, and 29% retain at least 90% of the load (see Figure 10).

Curtailment Duration

The analysis calculated the average hourly duration of curtailment events (i.e., the length of time the new load is curtailed during curtailment events). All hours in which any curtailment occurred were included, regardless of magnitude. The results for each balancing authority and curtailment limit are presented in Figure 11. The average duration across BAs was 1.7 hours for the 0.25% limit, 2.1 hours for the 0.5% limit, 2.5 hours for the 1.0% limit, and 4.5 hours for the 5.0% limit.

Figure 10. Hours of Curtailment by Load Curtailment Limit



Seasonal Concentration of Curtailment

The analysis reveals significant variation in the seasonal concentration of curtailment hours across balancing authorities. The winter-summer split ranged from 92% to 1% for CAISO (California Independent System Operator), where curtailment is heavily winter-concentrated, to 0.2% to 92% for AZPS,[22] which exhibited a heavily summer-concentrated curtailment profile (Figure 12a).[23]

Figure 11. Average Curtailment Duration by Balancing Authority and Curtailment Limit, Hours

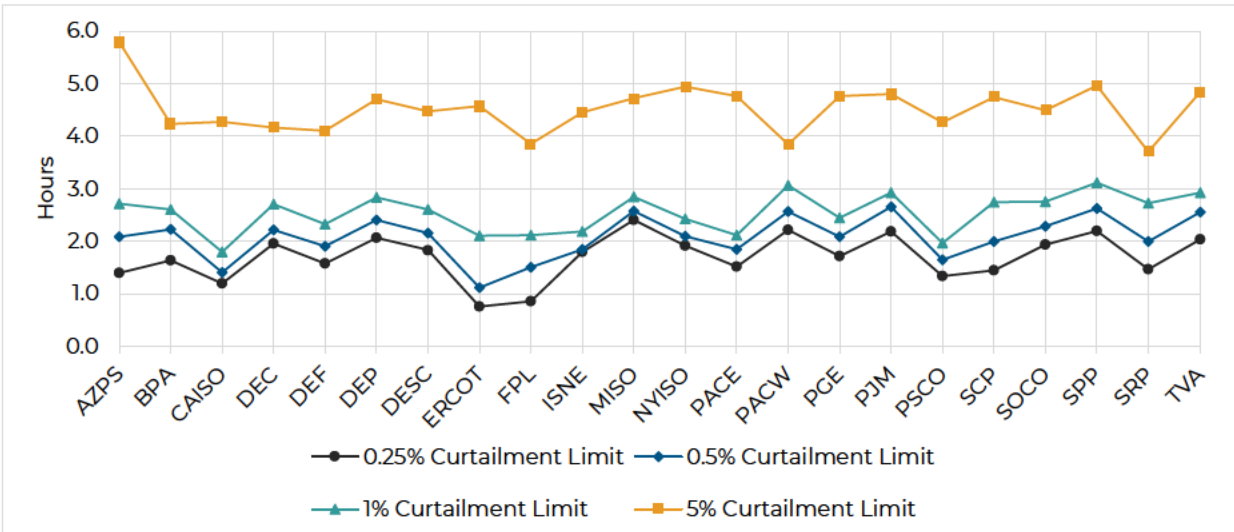
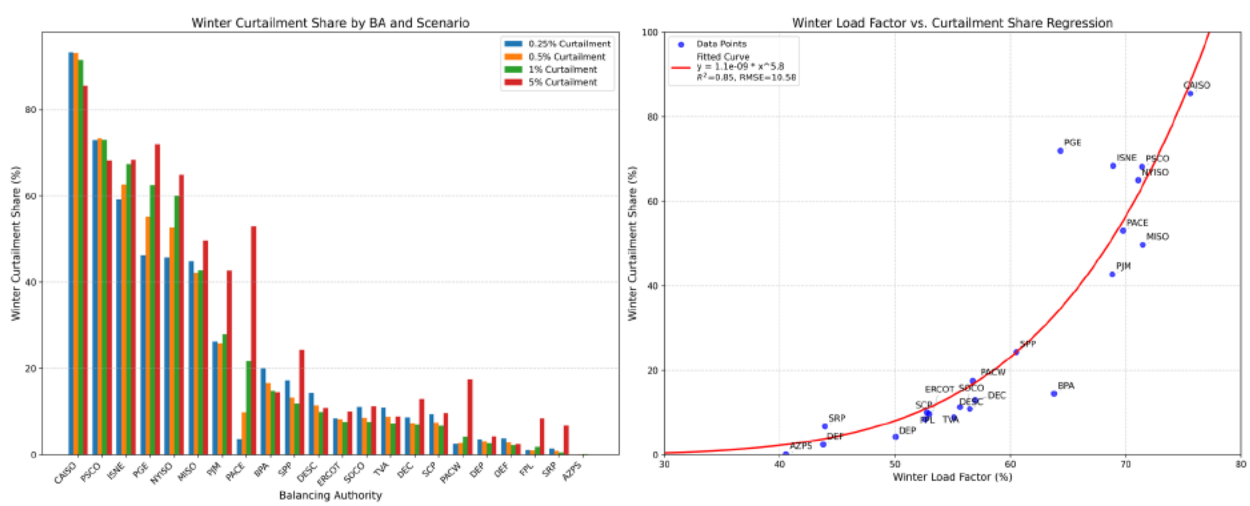


Figure 12. Seasonal Curtailment Analysis



(a) (b)

22 Note the remainder of the curtailment occurred in these BAs in shoulder months (i.e., not summer, not winter).

23 These values correspond to the seasonal curtailment concentration for the 1% curtailment limit.

A key observation is the strong correlation between the winter load factor (system utilization during winter months) and the seasonal allocation of curtailment hours (Figure 12b). BAs with lower winter load factors—indicating reduced system utilization during winter—tend to have greater capacity to accommodate additional load in winter while experiencing a dispro-portionately higher share of curtailment during summer months. This trend is particularly pronounced in balancing authorities located in the Sun Belt region, resulting in a lower win-ter concentration of curtailment hours.

While most BAs exhibited relatively stable seasonal curtailment shares across increasing load addition thresholds, some demonstrated notable shifts in seasonal allocation as load additions increased (e.g., PACW, FPL, NYISO, ISO-NE, PACE, PGE). These shifts highlight the dynamic interplay between system demand patterns and the incremental addition of new load.

Figure 12a illustrates this variability, showcasing the relationship between winter load factor and winter curtailment share across curtailment scenarios.[24]

Discussion

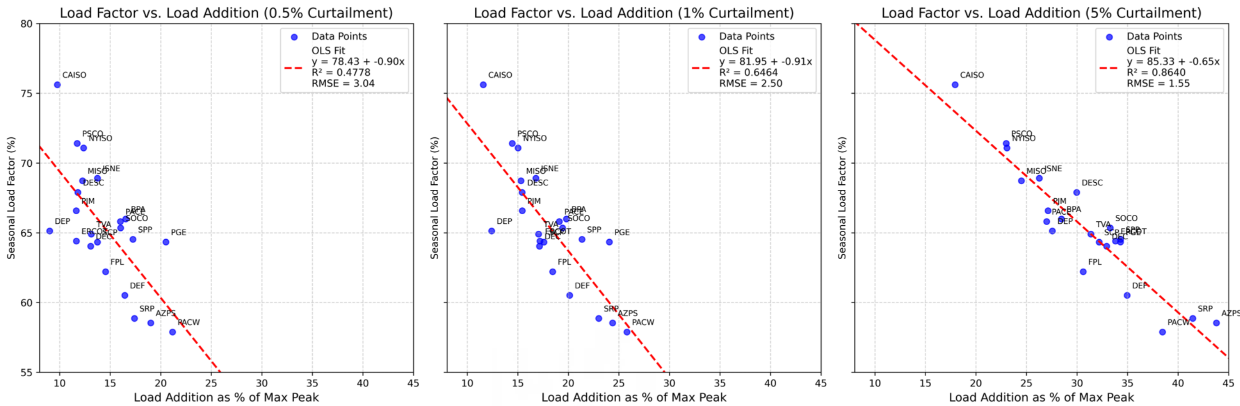
The results highlight that the significant headroom in US power systems—stemming from their by-design low load factors—could be tapped to enable the integration of substantial load additions with relatively low rates of load curtailment. They also underscore substantial variation in flexibility across balancing authorities, driven by differences in seasonal and aggregate load patterns. This variation suggests that seasonal load factors may be strongly linked to how much additional load a balancing authority can integrate without requiring high curtailment rates.

To explore this relationship, we analyzed system load factors in relation to the additional load that each balancing authority could accommodate while limiting the load curtailment rate to 0.5%, 1.0%, and 5.0% (i.e., the load curtailment limit). To allow for meaningful comparison across BAs, the additional load was standardized as a percentage of the BA's historical peak load. To account for whether a balancing authority's curtailment was concentrated in the summer or winter, the seasonal load factor was selected corresponding to the season with the highest share of curtailment.

The analysis revealed that BAs with higher seasonal load factors tended to have less headroom for the load curtailment limits examined (Figure 13). In simpler terms, systems with higher utilization during their busiest season had less power generation capacity planned to be available that could serve new load without hitting curtailment limits. For example, CAISO, with a seasonal load factor of 76%, could accommodate less additional load compared to PacifiCorp West (PACW) and AZPS, which exhibited lower seasonal load factors and supported larger load additions as a share of peak system load. This relationship grew in statistical significance as the load curtailment limit increased, yielding an R^2 value of 0.48 and an RMSE of 3.04 at the 0.5% curtailment limit, and an R^2 value of 0.86 and an RMSE of 1.55 at the 5% curtailment limit (i.e., 86% of the variation in load addition capacity across balancing authorities can be explained by differences in load factor at a curtailment limit of 5.0%).

24 Note in Figure 12b that a high-degree polynomial function captures the nonlinear growth in the area under the load curve as curtailed load exceeds a fixed peak threshold. This fit generally aligns with expectations, demonstrating that higher-degree terms are necessary to capture the relationship between load factor and curtailed load.

Figure 13. Load Factor Versus Max Load Addition as Share of Peak Load



These findings emphasize the importance of load factor as a predictor of curtailment-enabled headroom. BAs with more uneven peak seasonal demand—characterized by relatively low system utilization in winter or summer—tend to have greater capacity to integrate new loads with limited curtailment. Conversely, systems with more consistent demand across the winter and summer face tighter limits, as their capacity to absorb additional load is already constrained by elevated baseline usage.

Limitations

This analysis provides a first-order assessment of power generation capacity available for serving new curtailable loads, and hence is an exploration of the market potential for large-scale demand response. The primary focus of the analysis is to ensure that total demand, subject to curtailment limits for new load, stays below the system peak for which system planners have prepared. Other considerations important for planning—such as ensuring adequate transmission capacity, ramping capability, and ramp-feasible reserves, among others—are beyond the scope of this study and therefore the results cannot be taken as an accurate estimate of the load that can be added to the system. Additionally, the analysis assumes the new loads do not change current demand patterns but rather shift the existing demand curves upward, and a more precise assessment of the potential for integration of new loads would require detailed characterization of the temporal patterns of the load. There is significant variation in how system operators forecast and plan for system peaks, accounting for potential demand response, and as a result there will be differences in the methods used to estimate potential to accommodate new load. Despite these limitations, the results presented here signal a vast potential that, even if overstated, warrants further research.

On the other hand, some aspects of this study may have contributed to an underestimation of available headroom. First, the analysis assumes that each BA's maximum servable load in the winter and summer is equivalent to the BA's highest realized seasonal peak demand based on the available historical data. However, the available generation capacity in each balancing authority should materially exceed this volume when accounting for the installed reserve margin. In other words, system operators have already planned their systems to accommodate load volume that exceeds their highest realized peak. Second, the analysis removed outlier demand values in some BAs to avoid using unreasonably high maximum peak thresholds, which would understate the curtailment rates. However, if some of the removed outliers properly represent a level of system load that the system is prepared to serve reliably, this analysis may have understated the curtailment-enabled headroom. Third, the analysis assumed all new load is constant and hence increases the total system load by the same gigawatt hour-by-hour, which would tend to overstate the absolute level of required gigawatt hour curtailment for a load that is not constant.

Future Analysis

Enhancing this analysis to more accurately assess the capacity to integrate large curtailable load would require addressing the following considerations:

Network Constraints

This analysis does not account for network constraints, which would require a power flow simulation to evaluate the ability of the transmission system to accommodate additional load under various conditions. As such, the results should not be interpreted as an indication that the identified load volumes could be interconnected and served without any expansions in network capacity. While the existing systems are planned to reliably serve their peak loads, this planning is based on the current load topology and the spatial distribution of generation and demand across the transmission network. A large new load could avoid exceeding aggregate peak system demand by employing flexibility, yet still cause localized grid overloads as a result of insufficient transmission capacity in specific areas. Such overloads could necessitate network upgrades, including the expansion of transmission lines, substations, or other grid infrastructure. Alternatively, in the absence of network upgrades, localized congestion could be addressed through the addition of nearby generation capacity, potentially limiting the flexibility and economic benefits of the new load. These factors underscore the importance of incorporating network-level analyses to fully understand the operational implications of large flexible load additions.

Intertemporal Constraints

This analysis does not account for intertemporal constraints related to load and generator operations. For load operations, response times affect system operations and management of operational reserves. Faster response times from flexible loads could alleviate system stress more effectively during peak demand periods, potentially reducing the reliance on reserve capacity. Conversely, slower response times may require additional reserves to bridge the gap between the onset of system imbalances and the load's eventual response. Moreover, the rapid ramp-down of large flexible loads could lead to localized stability or voltage issues, particularly in regions with weaker grid infrastructure. These effects may necessitate more localized network analyses to evaluate stability risks and operational impacts. On the generation side, intertemporal constraints such as ramping limits, minimum up and down times, and startup times can affect the system's ability to integrate fast-response demand. For instance, ramping constraints may restrict how quickly generators can adjust output to align with the curtailment of flexible loads, while minimum uptime and downtime requirements can limit generator flexibility.

Loss of Load Expectation

Peak load is a widely used proxy for resource adequacy and offers a reasonable indicative metric for high-level planning analyses. However, a more granular assessment would incorporate periods with the highest loss of load expectation (LOLE), which represent the times when the system is most likely to experience supply shortfalls. Historically, LOLE periods have aligned closely with peak load periods, making peak load a convenient and broadly applicable metric. However, in markets with increasing renewable energy penetration, LOLE periods are beginning to shift away from traditional peak load periods. This shift is driven by the variability and timing of renewable generation, particularly solar and wind, which can alter the temporal distribution of system stress. As a result, analyses focused solely on peak load may understate or misrepresent the operational challenges associated with integrating large new loads into these evolving systems.

CONCLUSION

This study highlights extensive potential for leveraging large load flexibility to address the challenges posed by rapid load growth in the US power system. By estimating the curtailment-enabled headroom across balancing authorities, the analysis demonstrates that existing system capacity—intentionally designed to accommodate the extreme swings of peak demand—could accommodate significant new load additions with relatively modest curtailment, as measured by the average number, magnitude, and duration of curtailment hours.

The findings further emphasize the relationship between load factors and headroom availability. Balancing authorities with lower seasonal load factors exhibit greater capacity to integrate flexible loads, highlighting the importance of regional load patterns in determining system-level opportunities. These results suggest that load flexibility can play a significant role in improving system utilization, mitigating the need for costly infrastructure expansion and complementing supply-side investments to support load growth and decarbonization objectives.

This analysis provides a first-order assessment of market potential, with estimates that can be refined through further evaluation. In particular, network constraints, intertemporal operational dynamics, and shifts in loss-of-load expectation periods represent opportunities for future analyses that can offer a deeper understanding of the practical and operational implications of integrating large flexible loads.

In conclusion, the integration of flexible loads offers a promising, near-term strategy for addressing structural transformations in the US electric power system. By utilizing existing system headroom, regulators and market participants can expedite the accommodation of new loads, optimize resource utilization, and support the broader goals of reliability, affordability, and sustainability.

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ABBREVIATIONS

AI	Artificial intelligence
AZPS	Arizona Public Service Company
BA	balancing authority
BPA	Bonneville Power Administration
CAGR	compound annual growth rate
CAISO	California Independent System Operator
CLRs	controllable load resources
CPUs	central processing units
DEC	Duke Energy Carolinas
DEF	Duke Energy Florida
DEP	Duke Energy Progress East
DERs	distributed energy resources
DESC	Dominion Energy South Carolina
EIA	Energy Information Administration
EPRI	Electrical Power Research Institute
ERCOT	Electric Reliability Council of Texas
ERIS	Energy Resource Interconnection Service
FERC	Federal Energy Regulatory Commission's
FPL	Florida Power & Light
GPUs	graphics processing units
ICT	information, and communication technology
ISO-NE	ISO New England
LGIA	Large Generator Interconnection Agreement
LOLE	loss of load expectation
MISO	Midcontinent Independent System Operator
NYISO	New York Independent System Operator
PACE	PacifiCorp East
PACW	PacifiCorp West
PG&E	Pacific Gas and Electric
PGE	Portland General Electric Company
PJM	PJM Interconnection
PSCO	Public Service Company of Colorado
RMSE	Root mean square error
RTO/ISO	Regional transmission organization/independent system operator
SCP	Santee Cooper, South Carolina Public Service Authority
SEAB	Secretary of Energy Advisory Board
SLAs	service-level agreements
SOCO	Southern Company
SPP	Southwest Power Pool
SRP	Salt River Project Agricultural Improvement and Power District
TPU	tensor processing unit
TVA	Tennessee Valley Authority

APPENDIX A: CURTAILMENT-ENABLED HEADROOM PER BALANCING AUTHORITY

Figure A.1. Curtailment Rate Versus Load Addition by RTO/ISO, MW

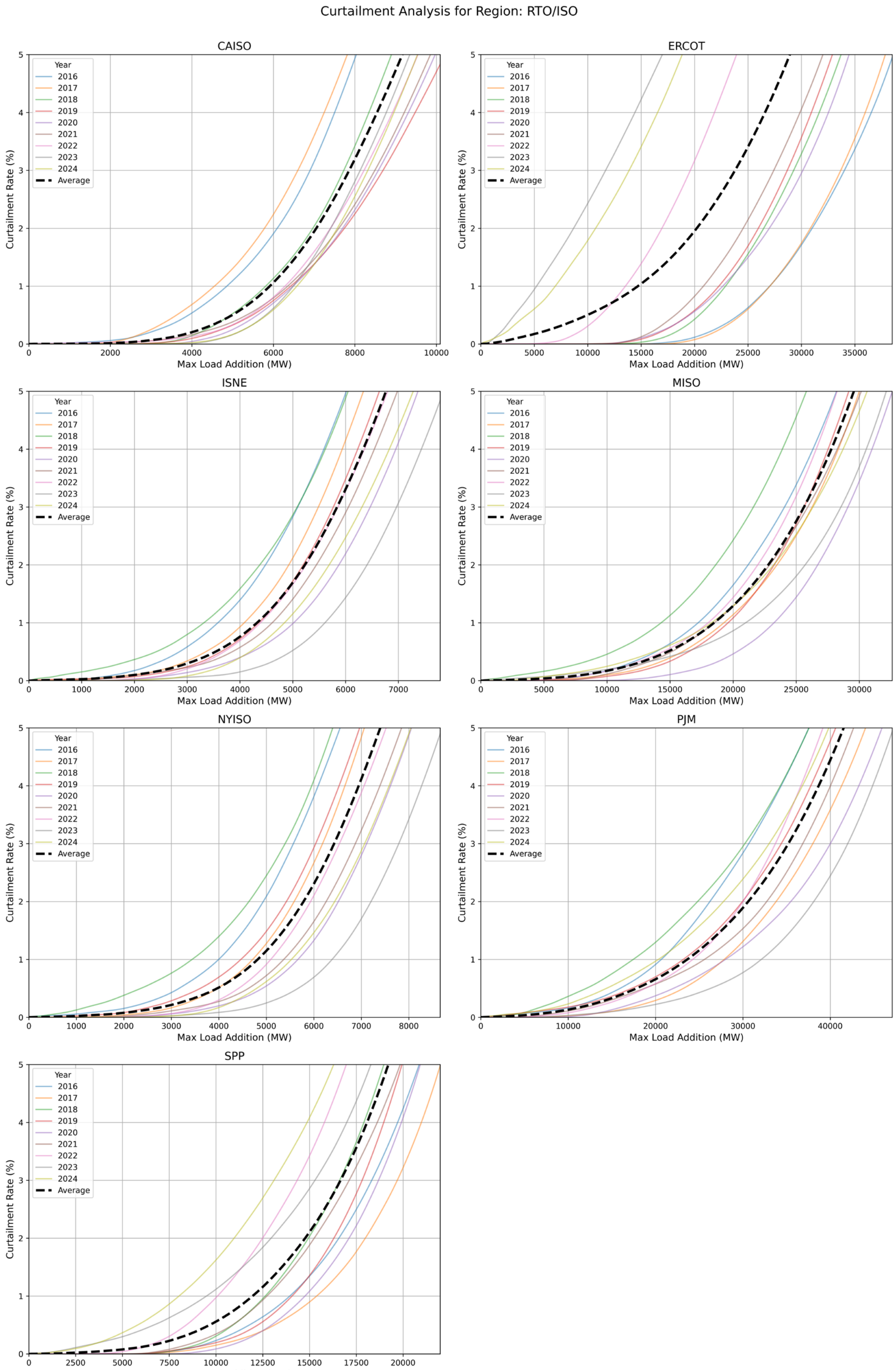


Figure A.2. Curtailment Rate Versus Load Addition by Non-RTO Southeastern Balancing Authority, MW

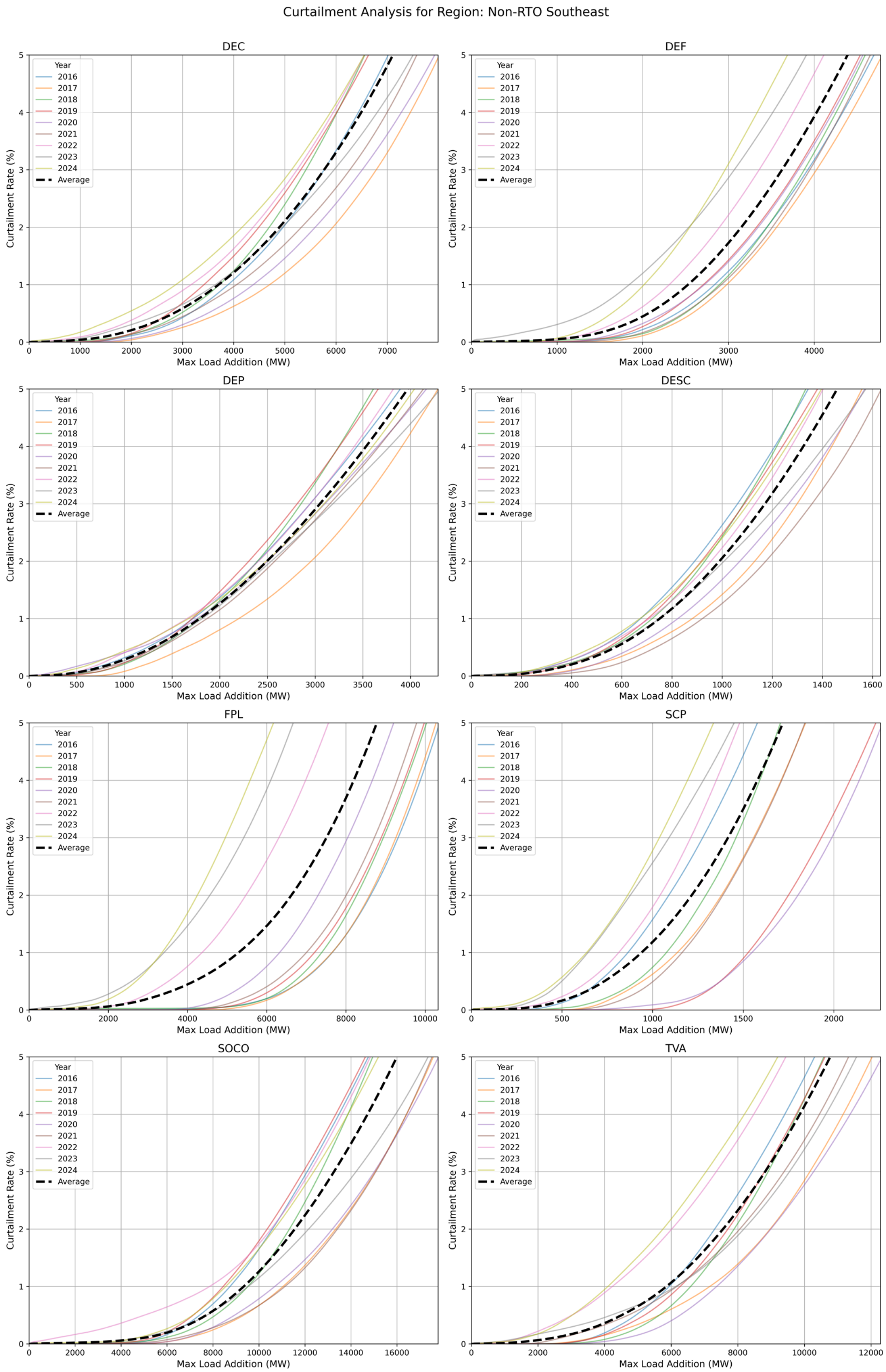
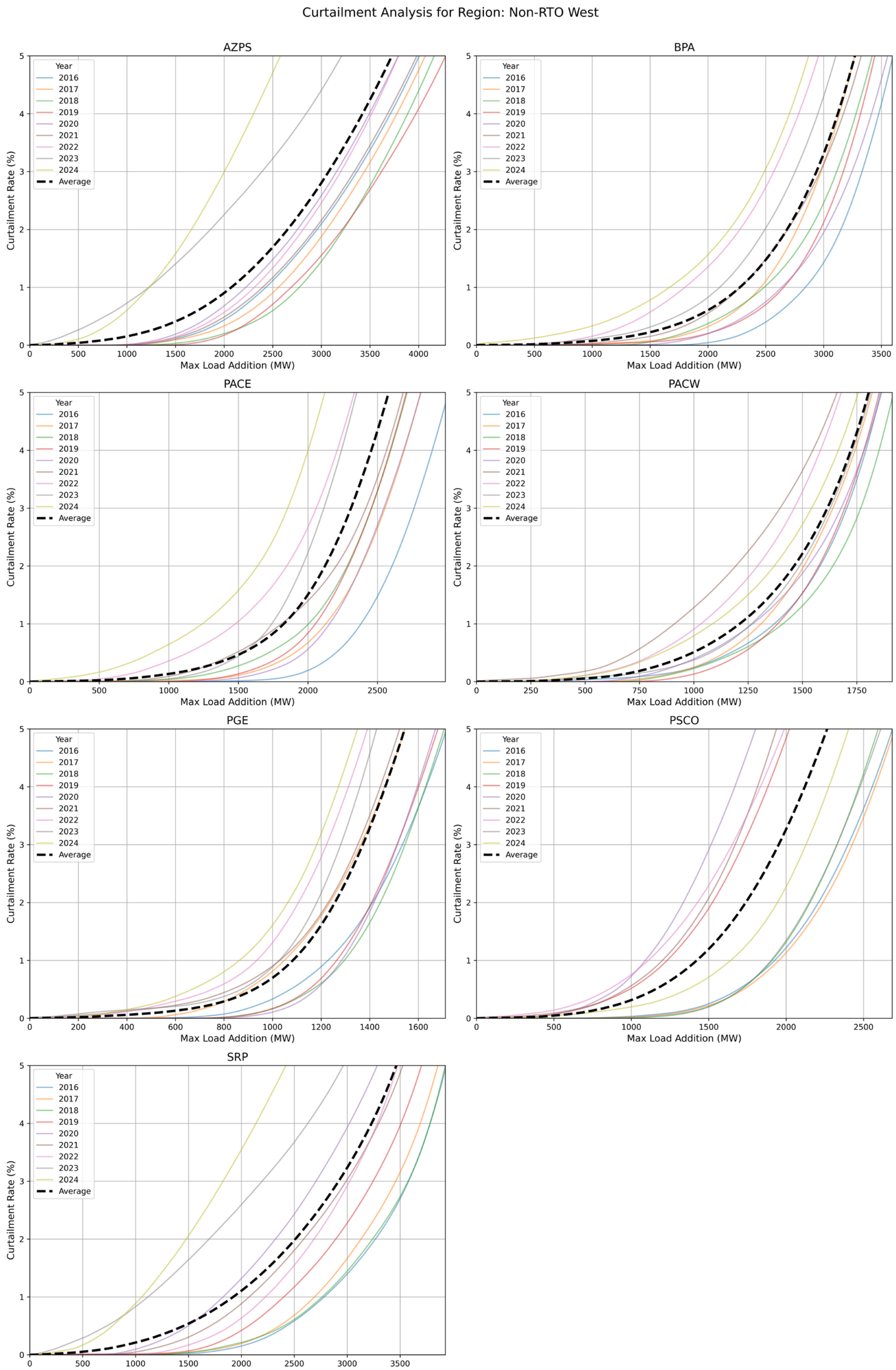


Figure A.3. Curtailment Rate Versus Load Addition by Non-RTO Western Balancing Authority, MW



APPENDIX B: DATA CLEANING SUMMARY

The data cleaning process attempted to improve the accuracy of nine years of hourly load data across the 22 balancing authorities, including the following steps:

1. Data normalization
    - **Dates:** Date-time formats were verified to be uniform.
    - **Demand data:** Where the balancing authority had an “Adjusted demand” value for a given hour, this value was used, otherwise its “Demand” value was used. The final selected values were saved as “Demand” and a log was kept.
    - **BA labels:** Labels were mapped to align with widely used acronyms, including:
        - CPLE → DEP
        - DUK → DEC
        - SC → SCP
        - SWPP → SPP
        - SCEG → DESC
        - FPC → DEF
        - CISO → CAISO
        - BPAT → BPA
        - NYIS → NYISO
        - ERCO → ERCOT
2. Identifying and handling outliers
    - **Missing and zero values:** Filled using linear interpolation between adjacent data points to maintain temporal consistency.
    - **Low outliers:** Demand values below a predefined cutoff threshold (such as 0 or extremely low values inconsistent with historical data) were flagged. Imputation for flagged low outliers involved identifying the closest non-outlier value within the same balancing authority and time period and replacing the flagged value.
    - **Spikes:** Sudden demand spikes that deviated significantly from historical patterns were flagged. Corrections were applied based on nearby, consistent data.
    - **Erroneous peaks:** Specific known instances of demand peaks that are outliers (e.g., caused by reporting errors) are explicitly corrected or replaced with average values from adjacent time periods.
3. **Data validation**:
    - Seasonal and annual peak loads, load factors, and other summary statistics were computed and inspected to ensure no unexpected results. Max peaks were compared to forecasted peaks collected by FERC to ensure none were out of range.
    - Logs summarizing corrections, including the number of spikes or outliers addressed for each balancing authority, were saved as additional documentation.

APPENDIX C: CURTAILMENT GOAL-SEEK FUNCTION

Mathematically, the function can be expressed as

$$\frac{1}{N}\sum_{y=1}^{N}\left(\frac{Curtailment_y(L)}{L\ \cdot\ 8{,}760}\cdot 100\right) = \ CurtailLimit$$

where

L	=	load addition in MW (constant load addition for all hours)
N	=	total number of years in the analysis (2016–2024)
$Curtailment_y(L)$	=	curtailed MWh for year y at load addition L
$L \cdot 8{,}760$	=	maximum potential energy consumption of the new load operating continuously at full capacity
$CurtailLimit$	=	predefined curtailment limit (e.g., 0.25%, 0.5%, 1.0%, or 5.0%).

For each hour t in year y, the curtailment is defined as

$$Curtailment_t(L) = \max(0, Demand_t + L - Threshold_t)$$

where

L	=	load addition being evaluated in MW
$Demand_t$	=	system demand at hour t in MW
$Threshold_t$	=	seasonal peak threshold applicable for hour t in MW (i.e., the maximum winter or summer peak across all years)

These hourly curtailments are aggregated to find the total annual curtailment

$$Curtailment_y(L)\ =\sum_{t\ \in\ T_y} Curtailment_t(L)$$

where

T_y	=	all hours in year y.

Replacing $Curtailment_y(L)$ in the original formula, the integrated formula becomes

$$\frac{1}{N}\sum_{y=1}^{N}\left(\frac{\sum_{t\ \in\ T_y}\max(0, Demand_t +\ L\ -\ Threshold_t)}{L\ \cdot\ 8{,}760} * 100\right) = \ CurtailLimit$$