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

CONFIDENTIALITY

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

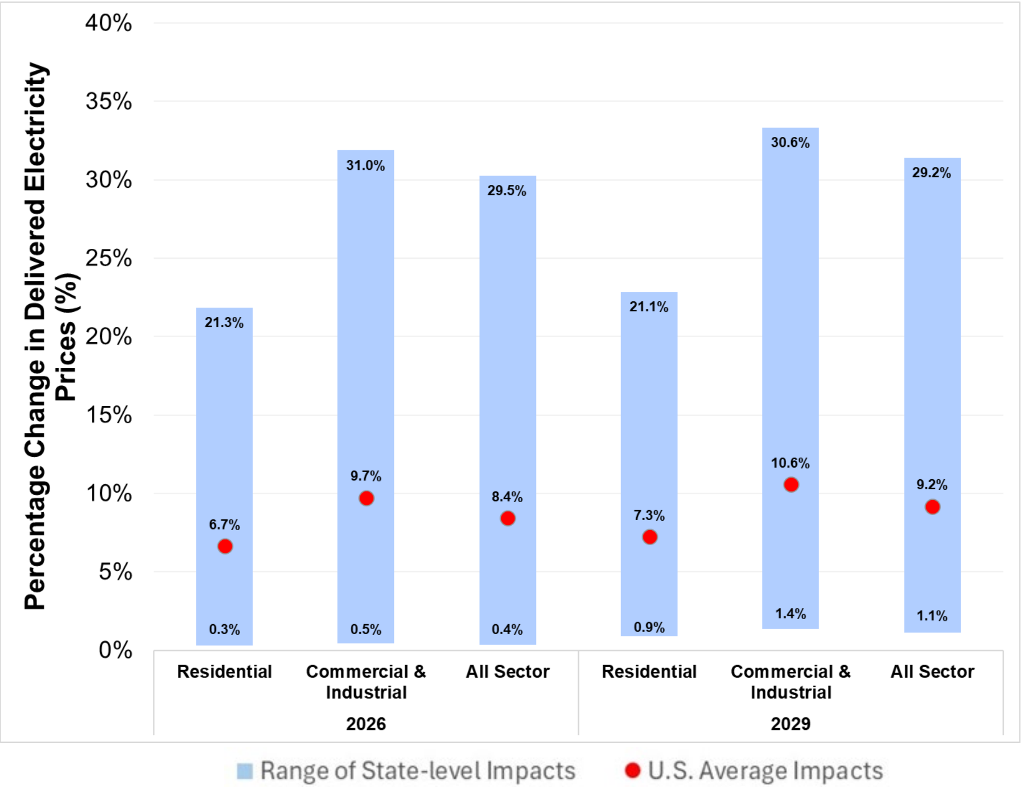
The technology-neutral tax incentives has the effect of reducing delivered electricity prices to the ratepayers.

- 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

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.

2

Overview of the Key Modeling Assumptions

Overview of Technology-Neutral Tax Incentives

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

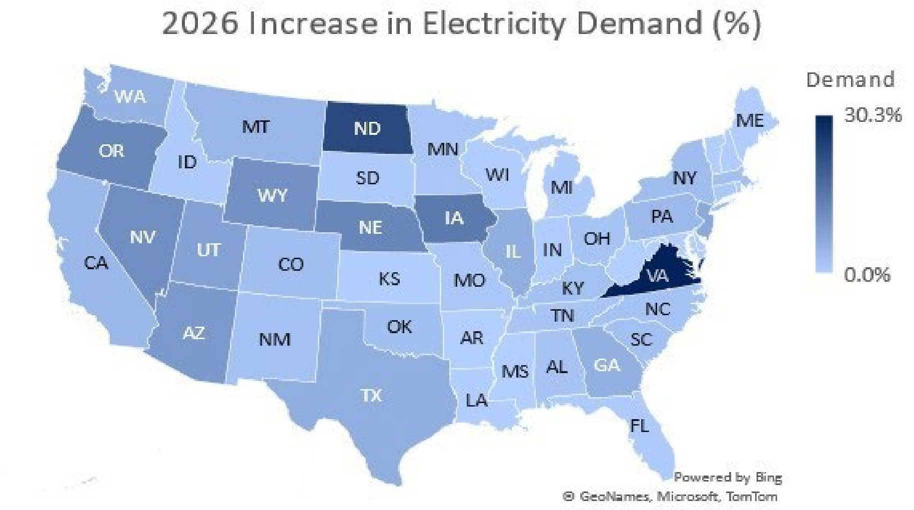
- For this study, two types of tax incentives are incorporated: §45Y production tax credit (PTC) and the §48E investment tax credit (ITC) to model the impact of the tax incentives on renewable technologies.
- The ITC was assumed to apply to capital-intensive technologies while the PTC was assumed to 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.

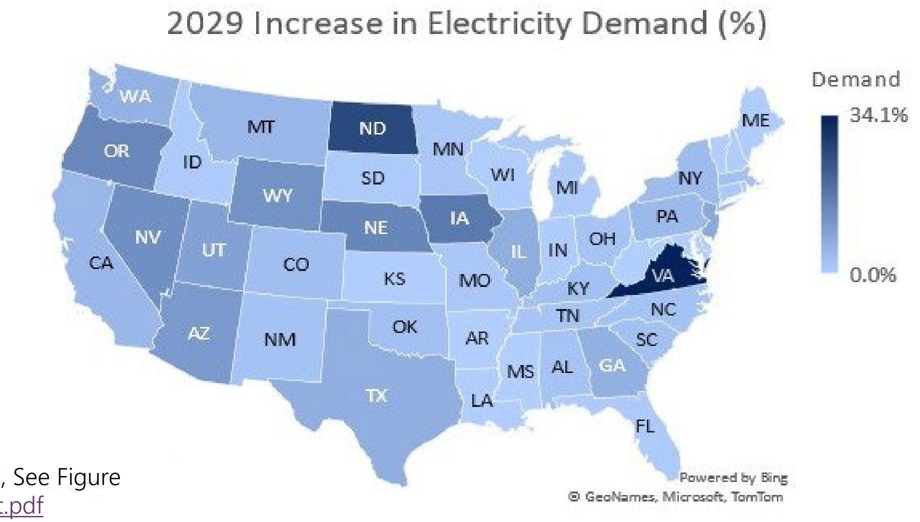
[1] U.S. EIA, AEO2023 Issues in Focus: Inflation Reduction Act Cases in the AEO2023, March 2023, available at https://www.eia.gov/outlooks/aeo/IIF_IRA/pdf/IRA_IIF.pdf;
U.S. EIA, Assumptions to the Annual Energy Outlook 2023: Renewable Fuels Module, March 2023, available at https://www.eia.gov/outlooks/aeo/assumptions/pdf/RFM_Assumptions.pdf

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).



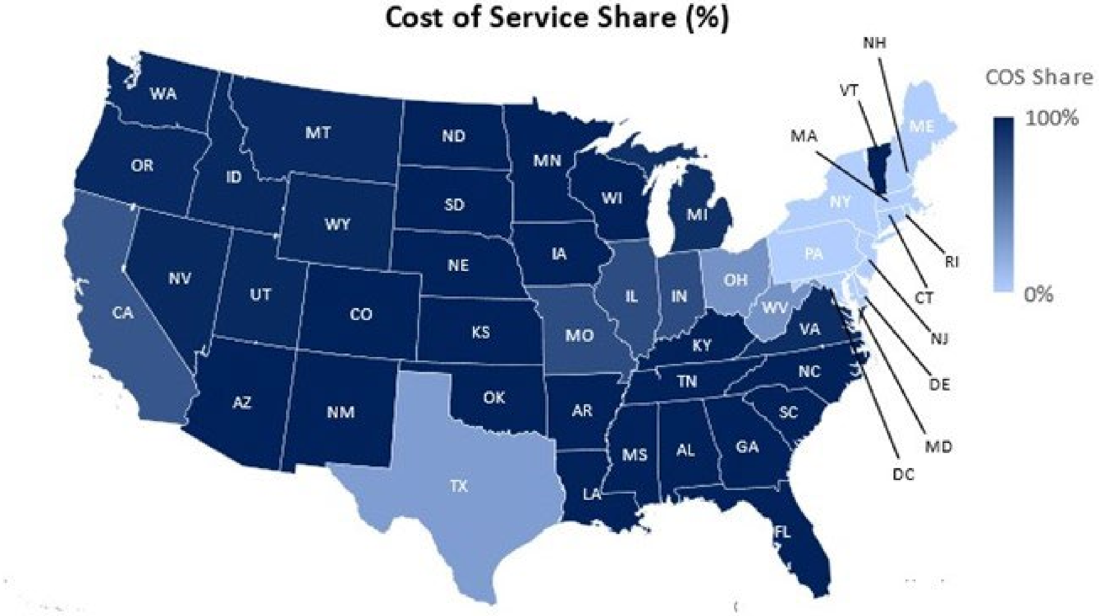


[1] EPRI, Powering Intelligence: Analyzing Artificial Intelligence and Data Center Energy Consumption, May 28, 2024, available at https://www.epri.com/research/products/3002028905
[2] Berkeley Lab, Energy Analysis & Environmental Impacts Division, 2023 United States Data Center Energy Usage Report, December 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

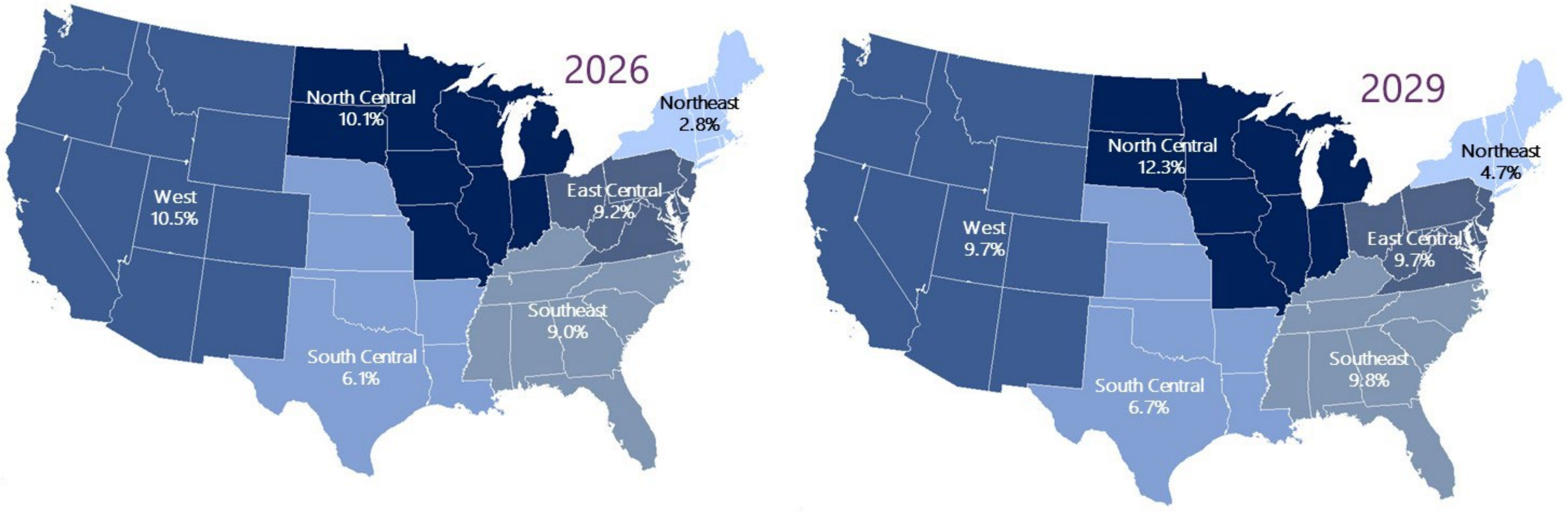
- The study evaluated two scenarios with and without different technology-neutral tax incentives for solar, solar with storage, solar thermal, onshore and offshore wind, geothermal, biomass, hydroelectric, and existing and new nuclear generating technologies.
- Both scenarios include incremental electricity 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).

4 Summary of Delivered Electricity Price Impact Results

NERA

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

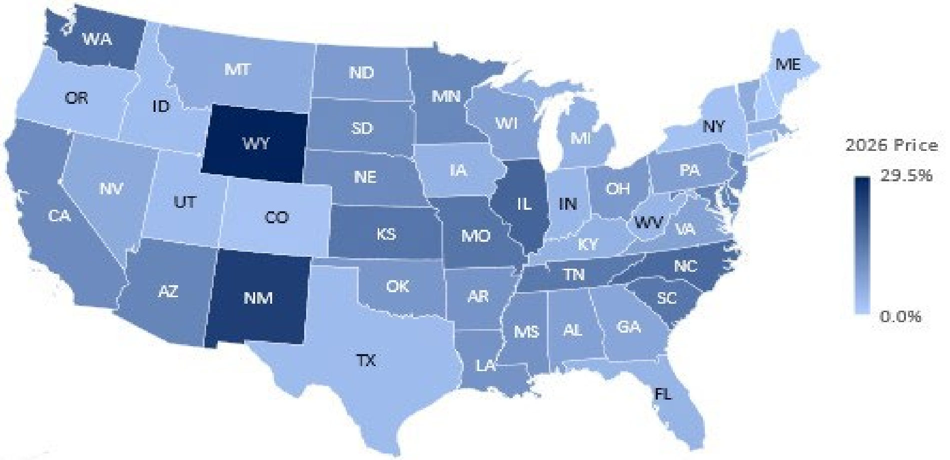
North Central and West regions are projected to see the highest increase in the average delivered electricity prices in the absence of the technology-neutral tax incentives. The impacts across the states within these broad regions are expected to vary based on the availability of deployment of low-cost 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.

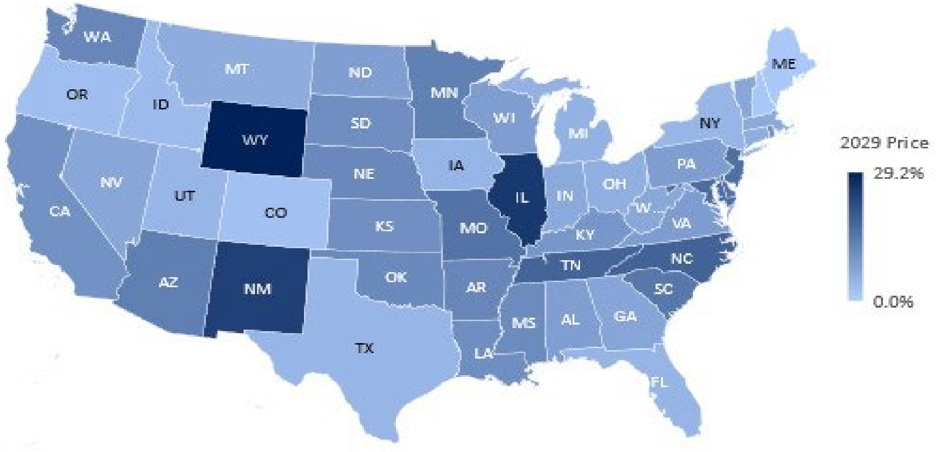


Average U.S. Electricity Price Impacts in 2026 and 2029, by State

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

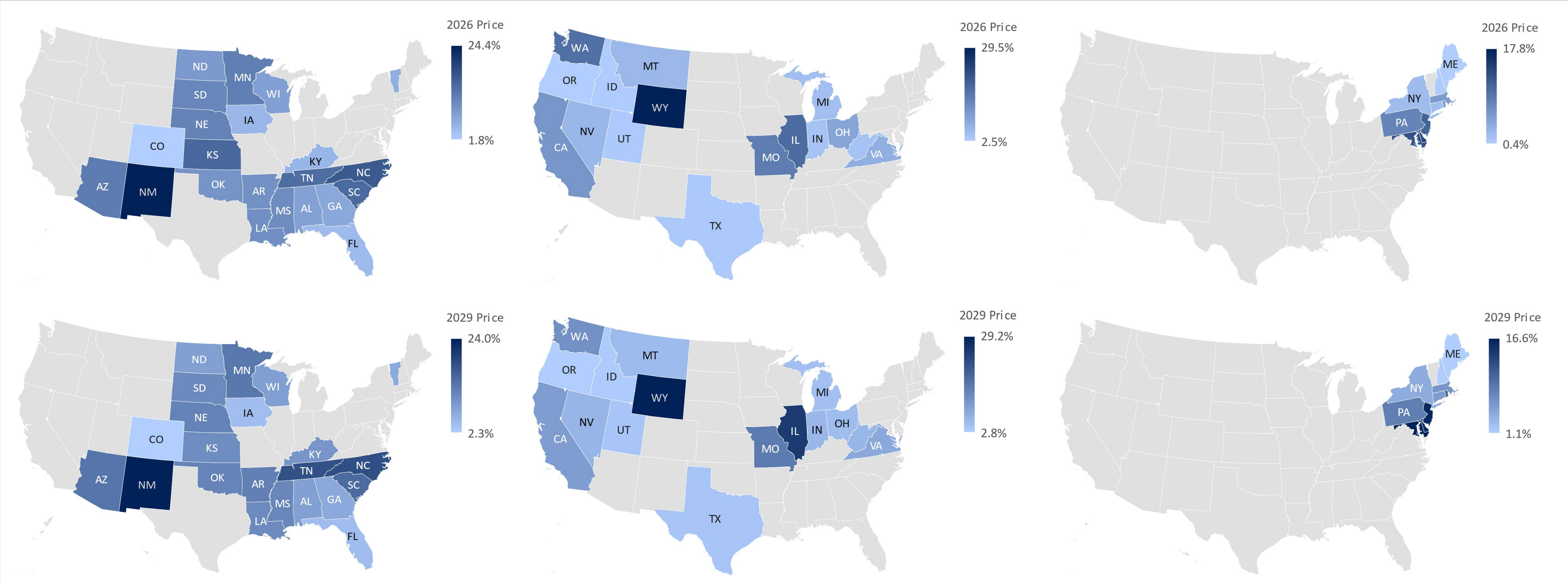
Average U.S. Electricity Price Impacts by Electricity Market Structure in 2026 and 2029

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

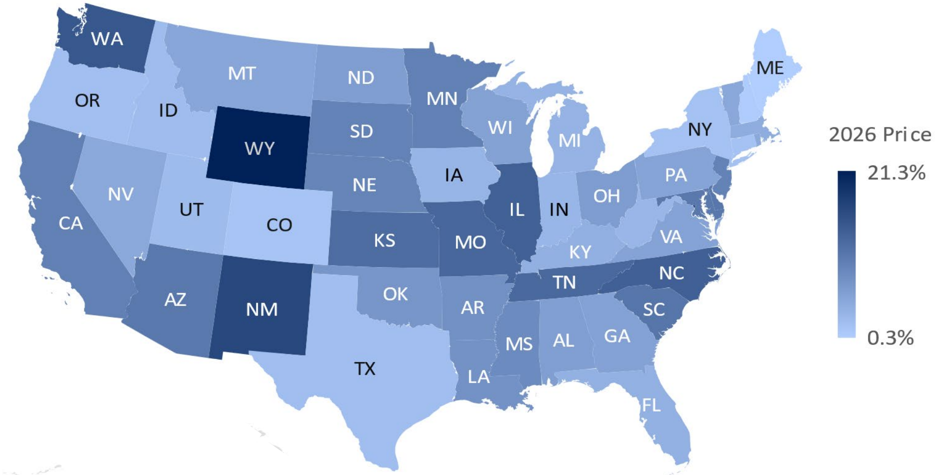


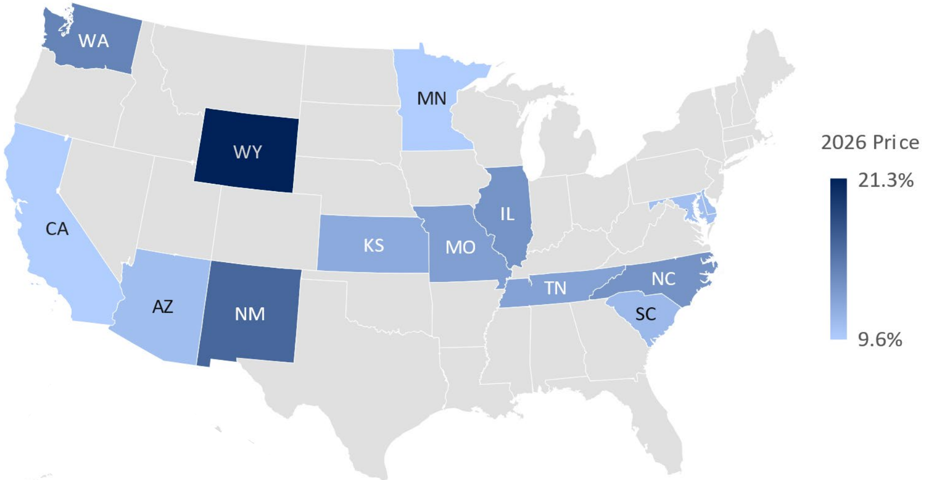
** See Appendix for detailed state-level results*

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.



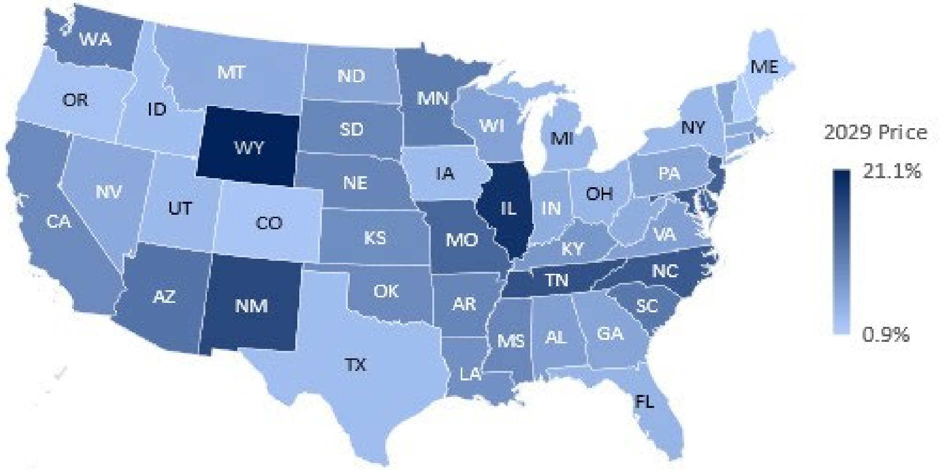


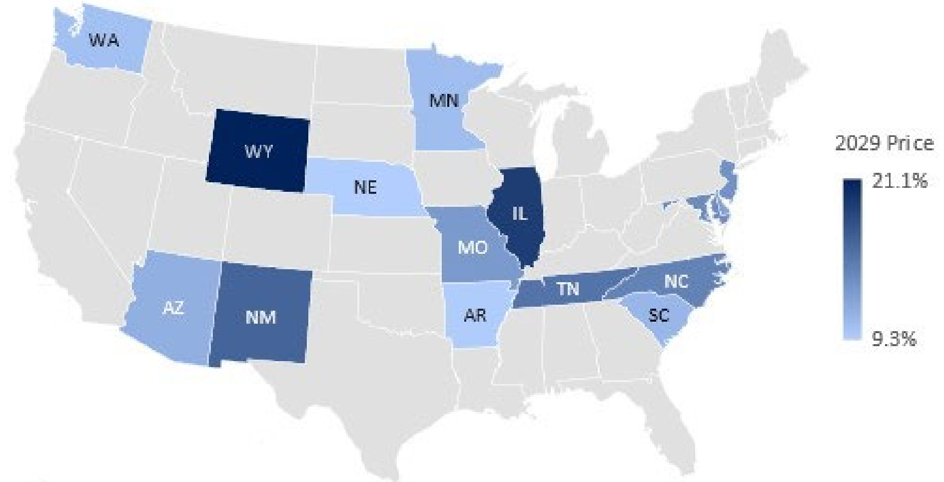
*Refer to the Appendix for the residential price impacts for the top 15 states in 2026, based on the absolute price changes

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)

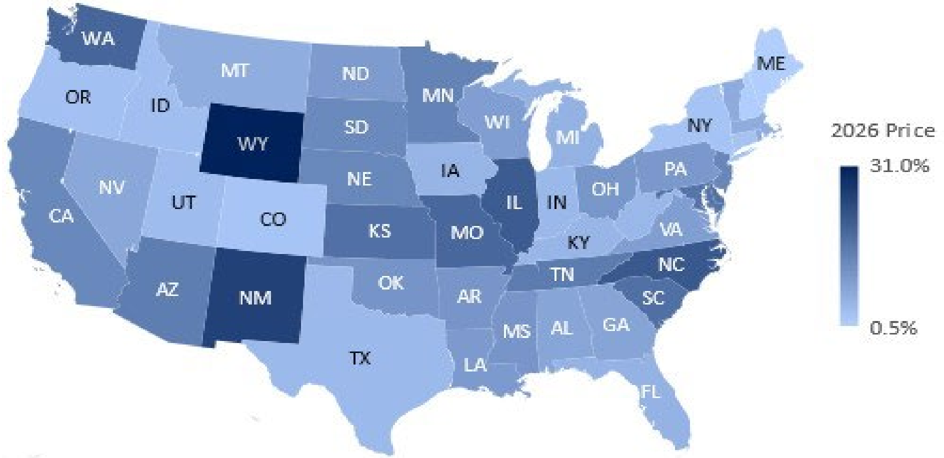
Percentage Increase in Average Residential Electricity Price, Top 15 States

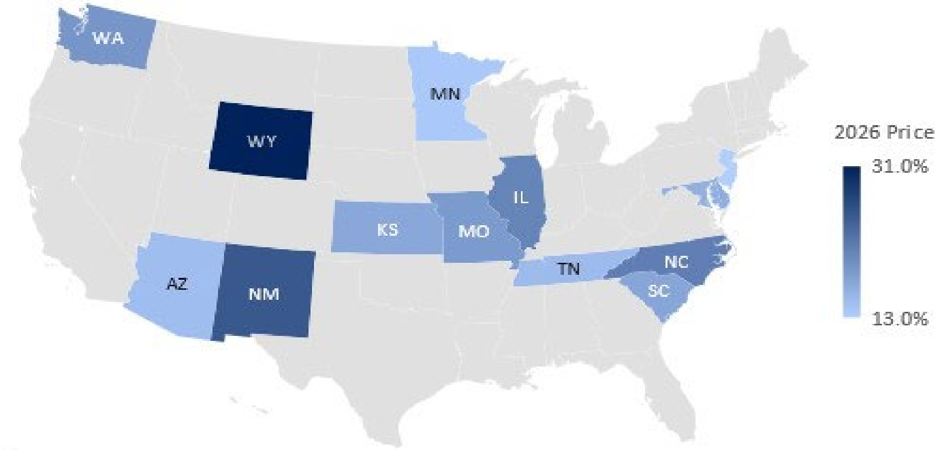
2026			2029		
State	**% Change**	**¢/kwh**	**State**	**% Change**	**¢/kwh**
WY	21.3%	2.6	WY	21.1%	2.7
DC	17.3%	3.1	IL	19.1%	4.4
NM	16.5%	2.6	NM	16.5%	2.7
WA	14.6%	1.6	TN	15.4%	1.8
NC	13.5%	1.8	NC	14.4%	2.0
IL	13.5%	2.1	MD	13.9%	2.4
MO	12.7%	1.6	NJ	13.4%	1.7
TN	12.5%	1.5	MO	12.9%	1.6
KS	12.0%	1.8	DE	12.3%	2.0
SC	10.9%	1.5	AZ	11.4%	1.7
DE	10.7%	1.8	SC	10.9%	1.9
AZ	10.6%	1.6	MN	10.4%	1.6
MD	10.6%	1.9	WA	10.2%	2.0
MN	9.6%	1.5	AR	9.4%	1.5
CA	9.6%	3.2	NE	9.3%	3.4

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.



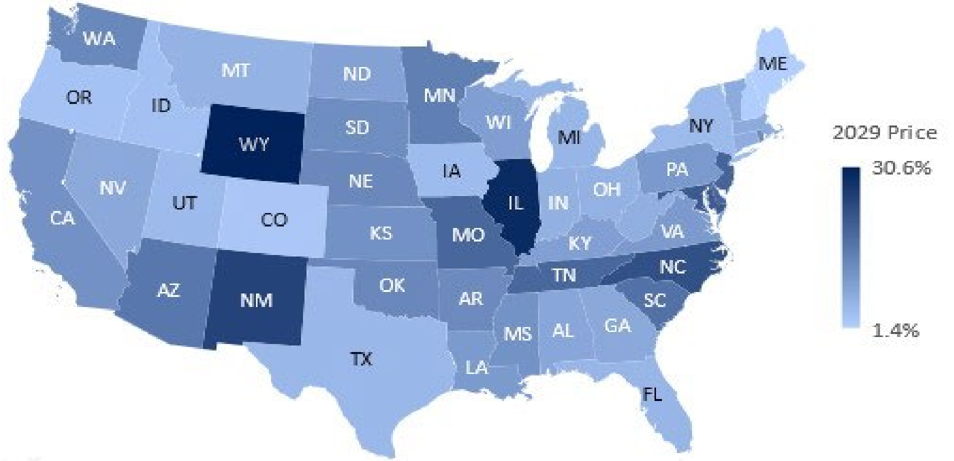


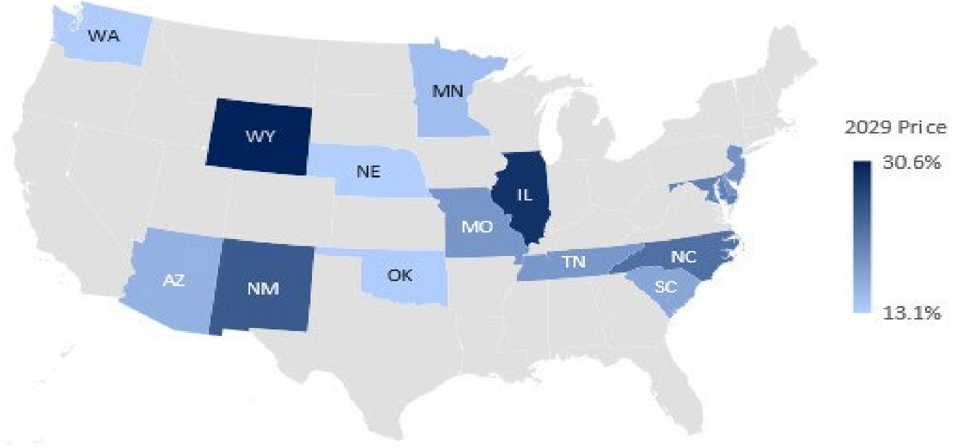
** Refer to the Appendix for the C&I price impacts for the top 15 states in 2026, based on the absolute price changes*

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

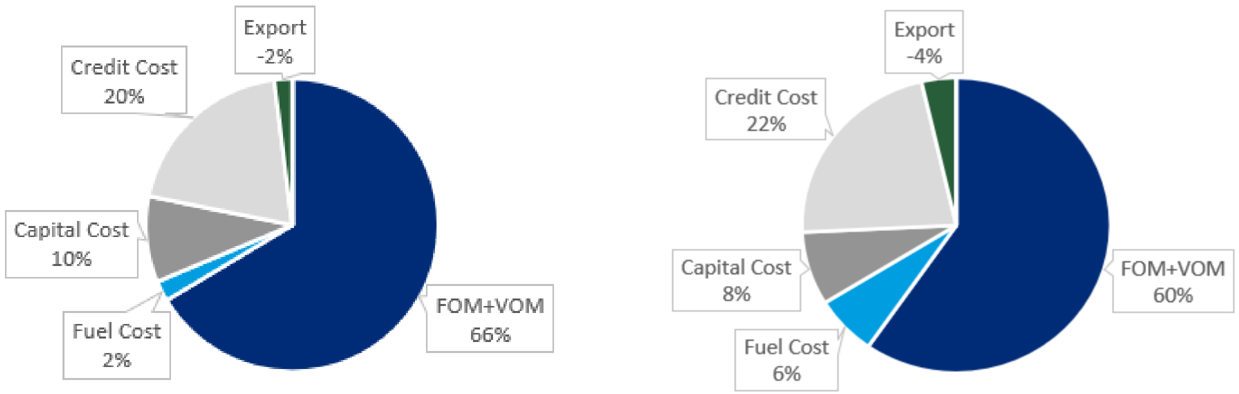
2026			2029		
State	**% Change**	**¢/kwh**	**State**	**% Change**	**¢/kwh**
WY	31.0%	2.6	WY	30.6%	2.7
NM	25.2%	2.6	IL	24.8%	2.8
NC	21.2%	1.8	NM	22.6%	2.5
IL	20.7%	2.1	NC	28.8%	2.6
DC	19.2%	3.1	MD	2.2%	0.3
WA	18.8%	1.6	NJ	13.2%	1.9
MO	18.4%	1.6	DE	18.7%	2.1
SC	17.2%	1.5	MO	17.0%	1.5
KS	16.9%	1.8	TN	11.7%	1.2
DE	16.6%	1.8	SC	19.0%	1.8
MD	16.2%	1.9	AZ	20.8%	2.3
TN	15.0%	1.5	MN	18.6%	2.2
AZ	14.7%	1.6	OK	15.9%	1.4
MN	13.6%	1.5	WA	14.7%	1.3
NJ	13.0%	2.0	NE	19.1%	1.7

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

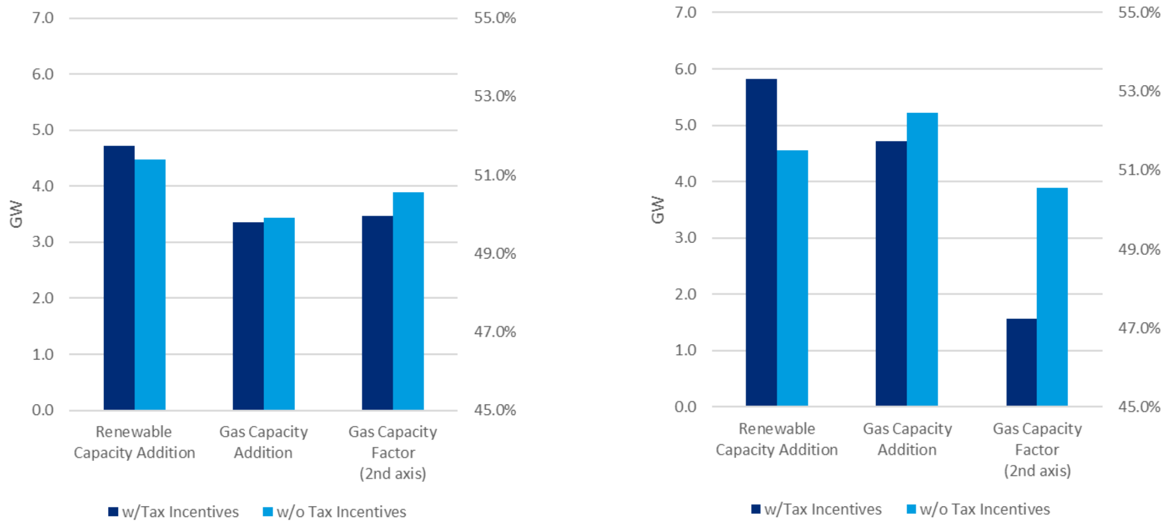
- NC is projected to have about 2 to 4 TWh of incremental load from data centers - about 2% increase in the total load.
- In the absence of technology-neutral tax incentives, NC adds a lower amount of renewables with concomitant increase in gas capacity addition and an increase in the capacity factor 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.

2026 **2029**

Electricity Price Impacts by Cost Components*



Changes in Generating Resources (NC)



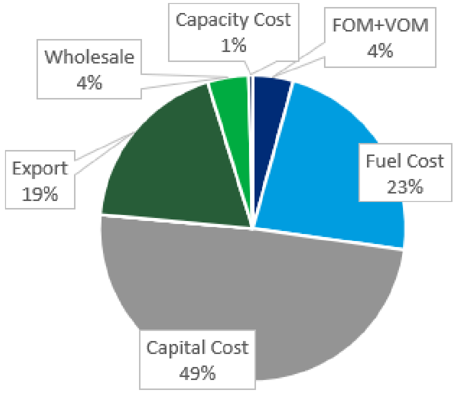
Note: The results from the NewERA model are for broader regions known as power pools which are then disaggregated to state level results using a mapping of electricity demand from the power pools to individual states.
* See Slides 44-45 for a description of the cost components

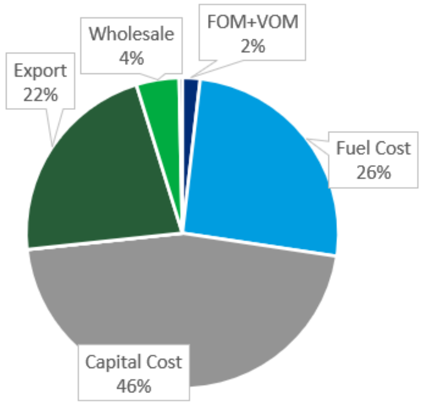
Wyoming: Drivers of Electricity Price Impacts in a Mixed Electricity Market Structure Region

- 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.

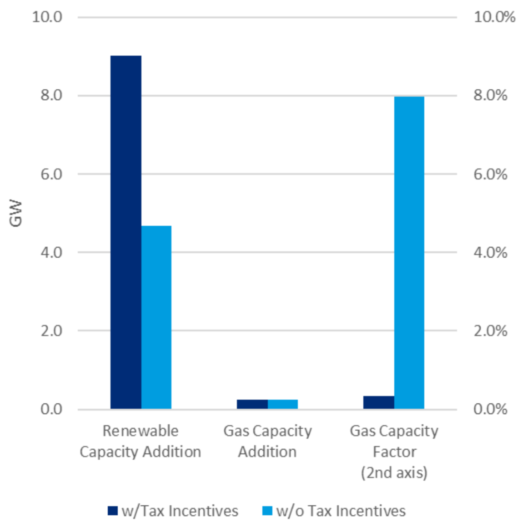
2026 **2029**

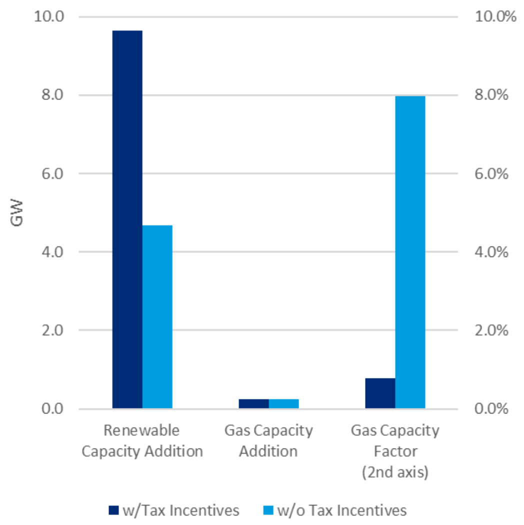
Electricity Price Impacts by Cost Components*





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.*

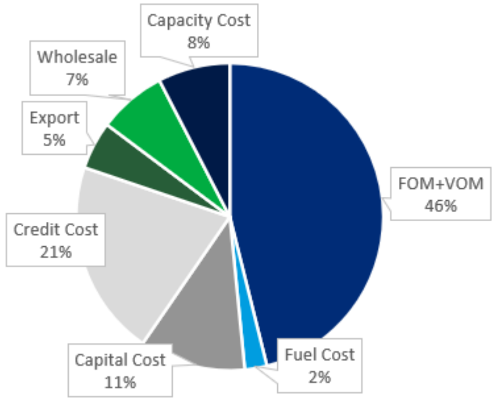
** See Slides 44-45 for a description of the cost components*

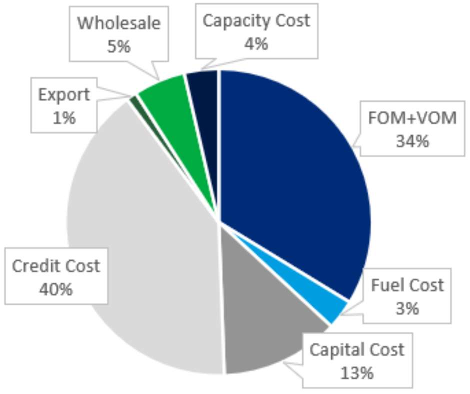
Illinois: Drivers of Electricity Price Impacts in a Mixed Electricity Market Structure Region

- 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.

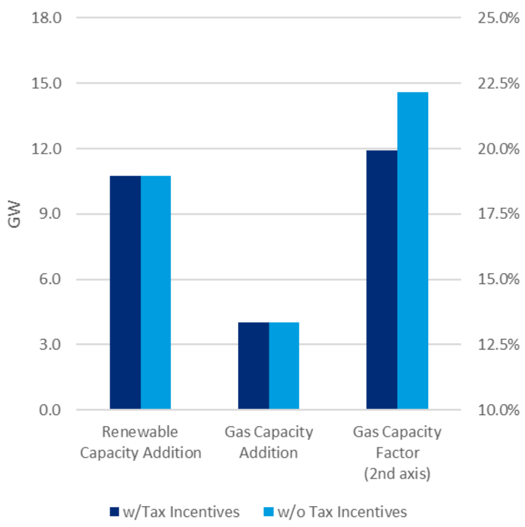
2026 **2029**

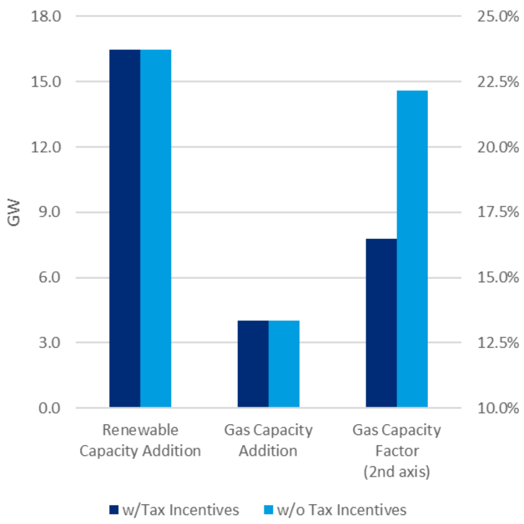
Electricity Price Impacts by Cost Components*





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.*

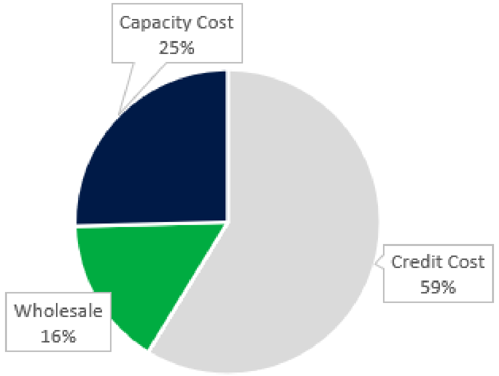
** See Slides 44-45 for a description of the cost components*

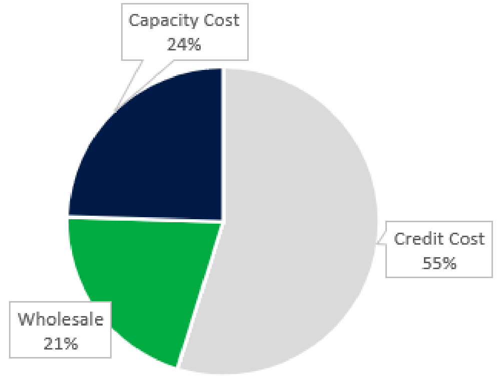
Pennsylvania: Drivers of Price Impacts in a Competitive Electricity Market Structure Region

- 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.

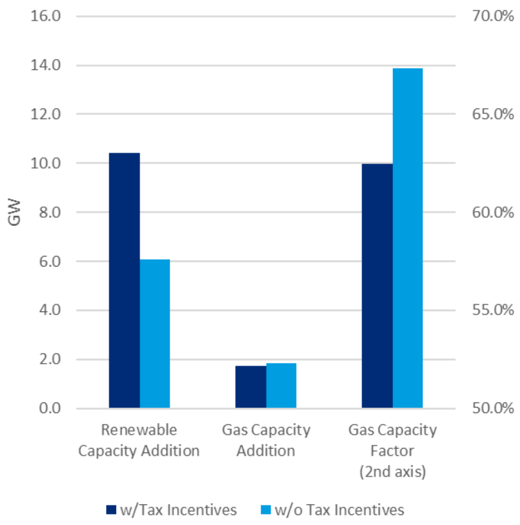
2026 **2029**

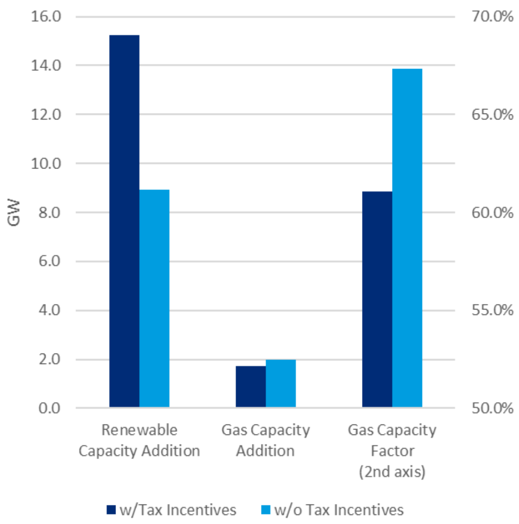
Electricity Price Impacts by Cost Components*





Changes in Generating Resources (PA)



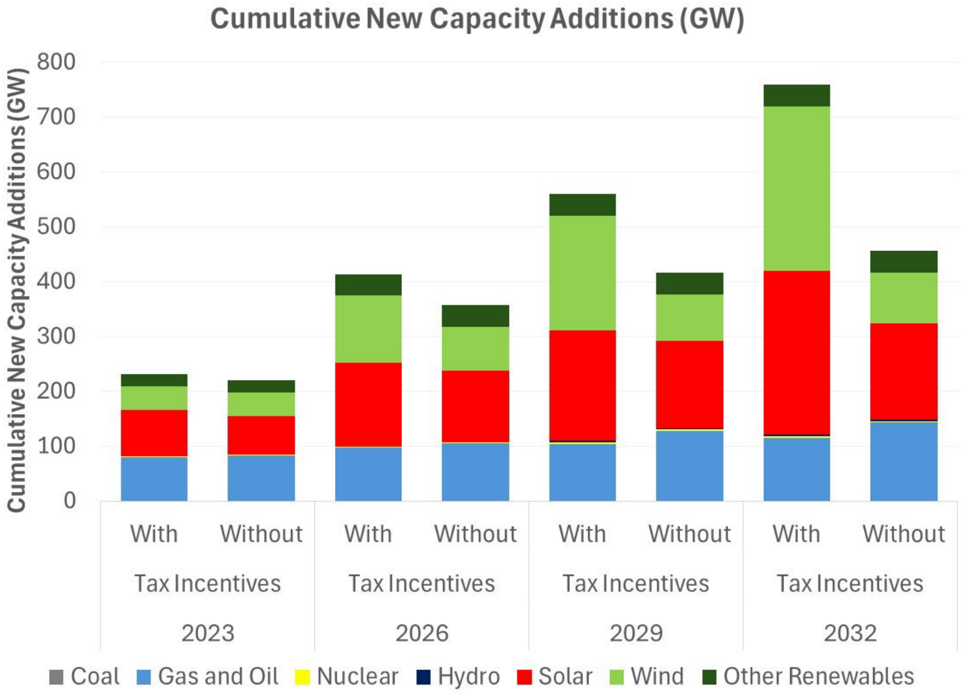


Note: *The results from the NewERA model are for broader regions known as power pools which are then disaggregated to state level results using a mapping of electricity demand from the power pools to individual states.*
** See Slides 44-45 for a description of the cost components*

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,.

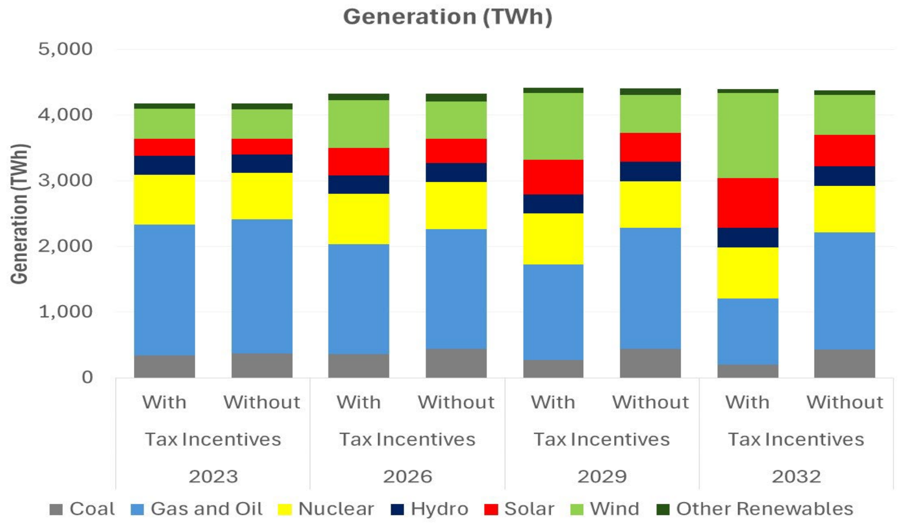
- New generation capacity incentivized by the technology-neutral tax credits are relatively more expensive in the scenario without the tax incentives which leads to lesser amount of new capacity additions of these technologies.
- By 2026 and 2029, there is a total reduction of 64 GW and 168 GW of solar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

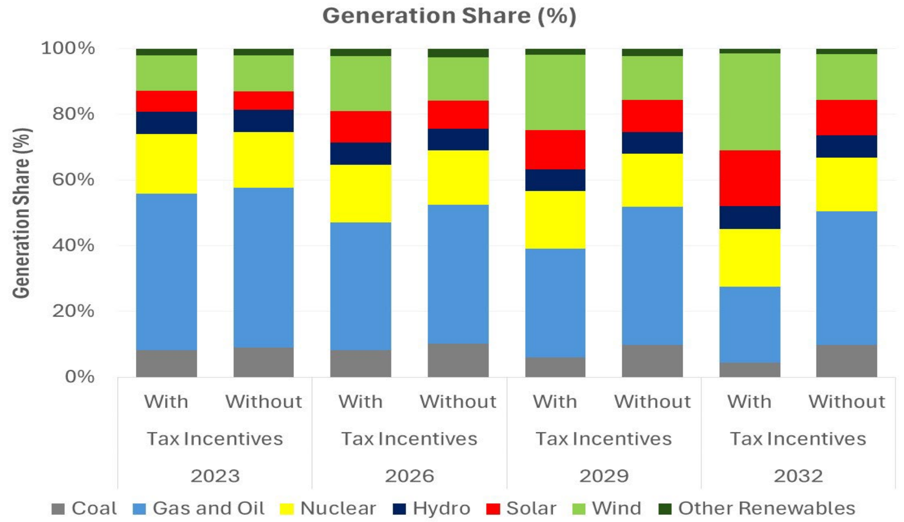


Generation by Type of Generating Technology

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:

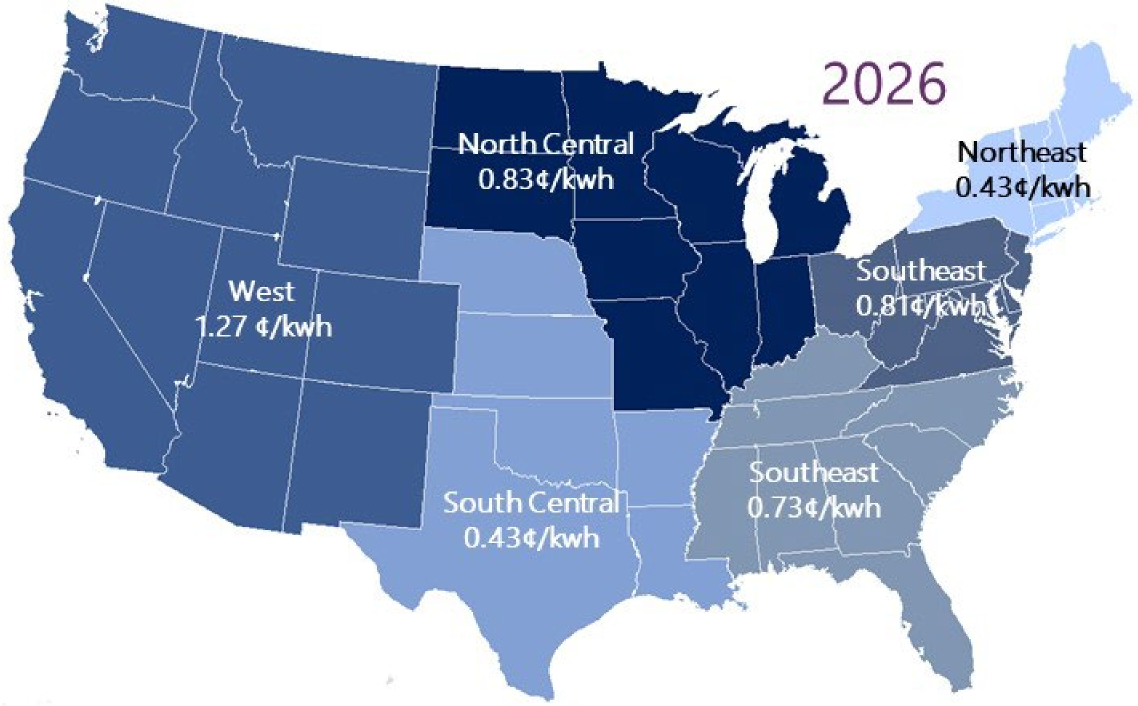
Additional Results

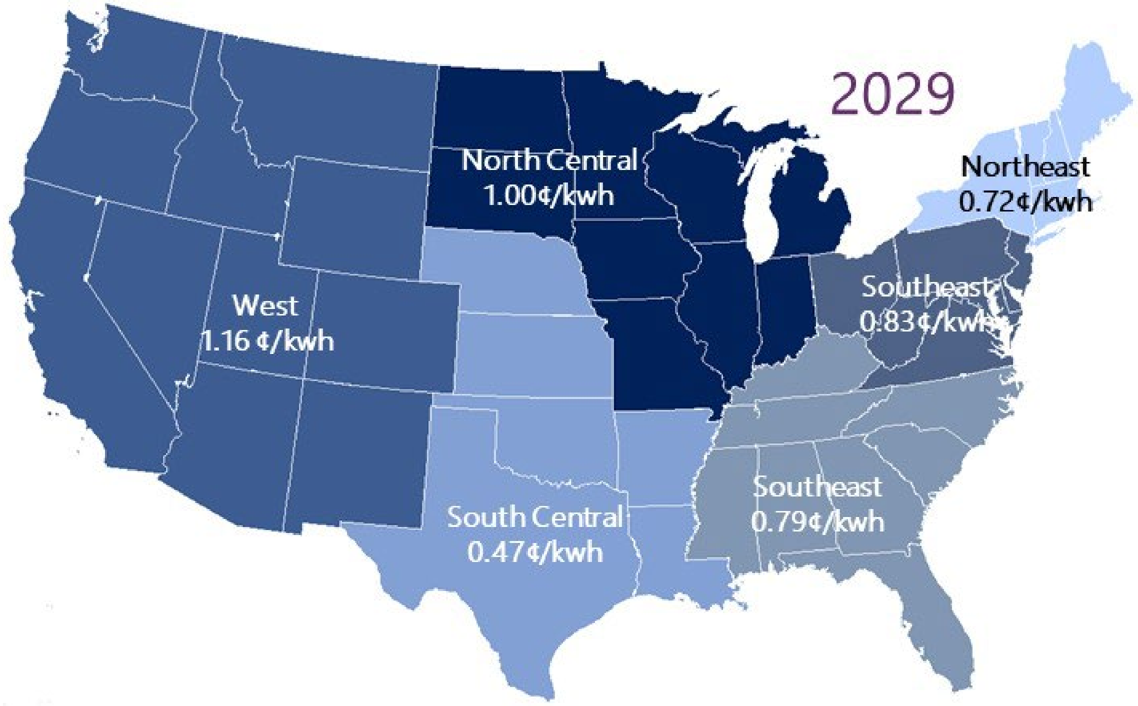
About the N_{ew}ERA Model

Technology-Neutral Tax Incentives

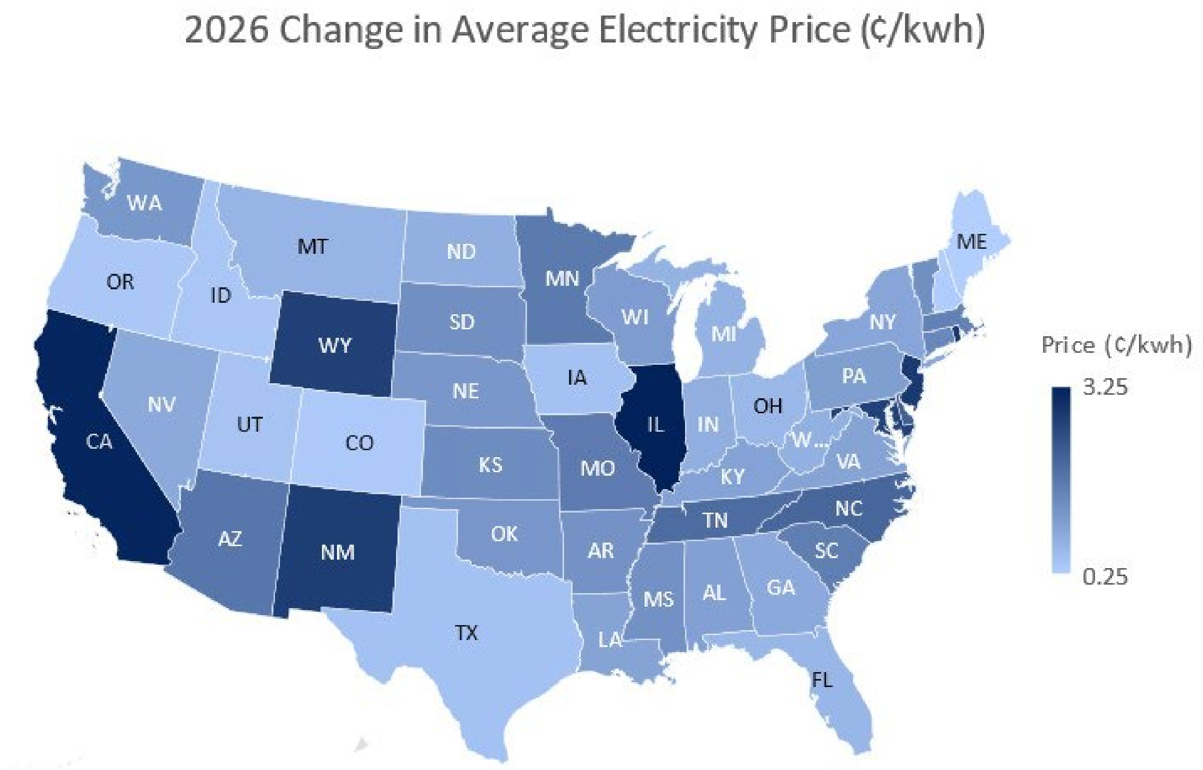
Additional Results: Average Delivered Electricity Price Impacts in 2026 and 2029, by Region (cents/kwh)

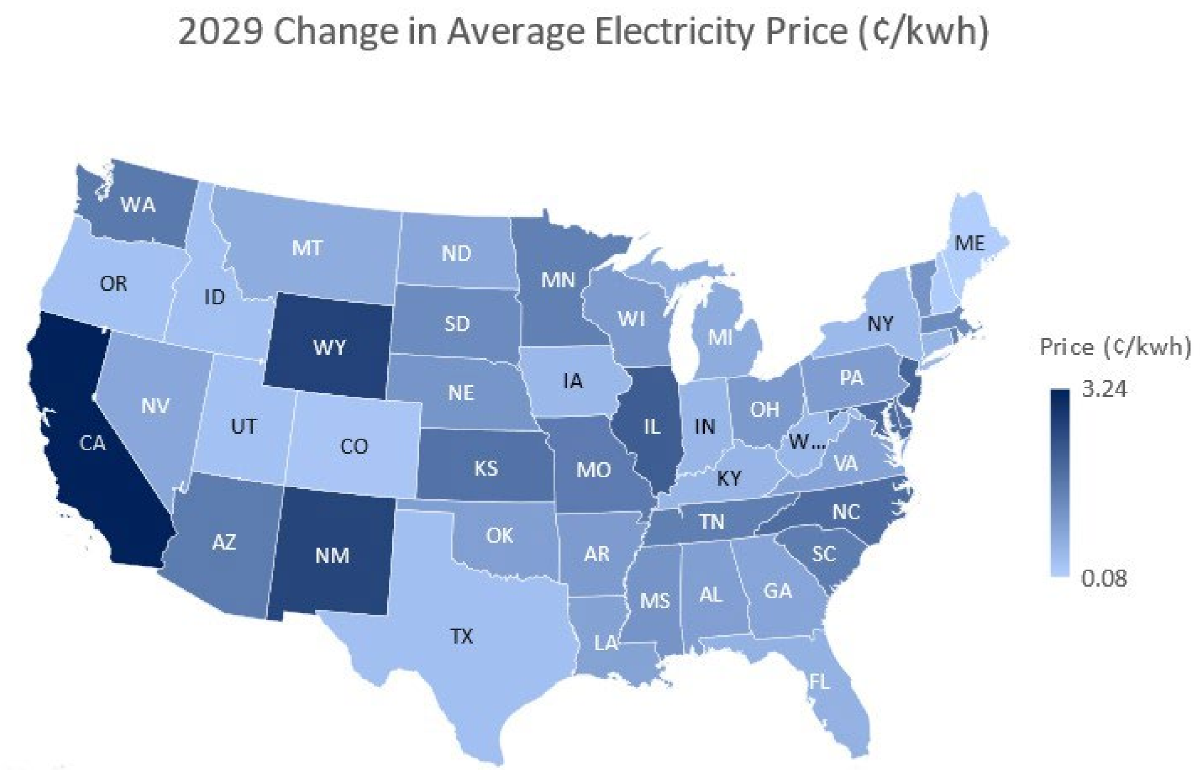
North Central and West regions are projected to see the highest increase in the average delivered electricity prices without the technology-neutral tax incentives. The impacts across the states within these broad regions will varying.



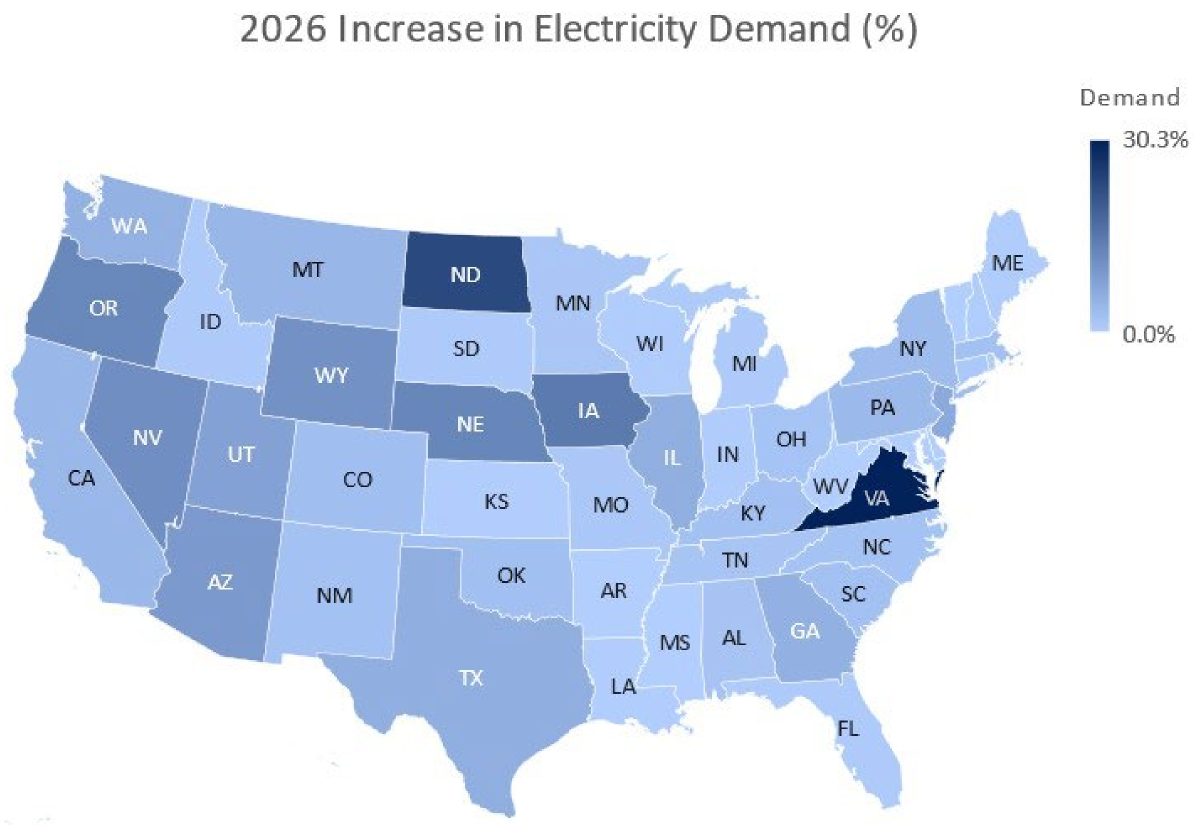


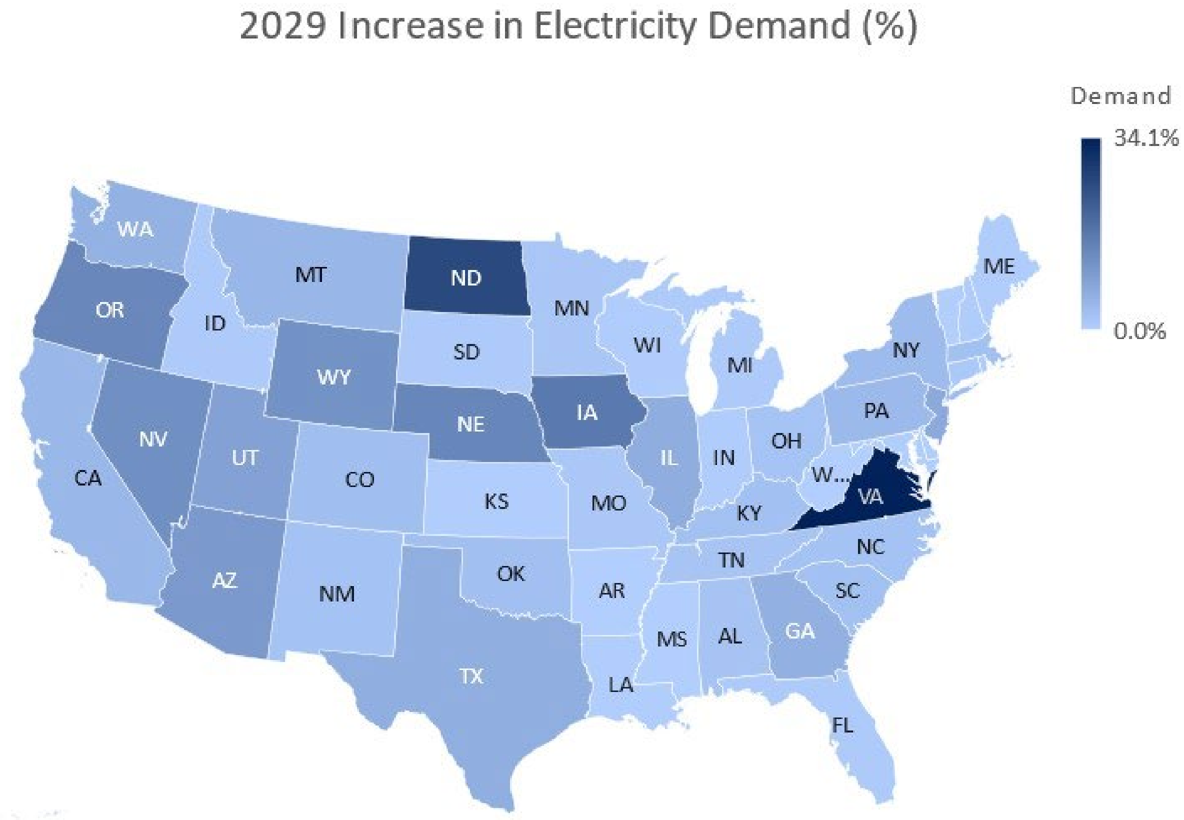
Additional Results: Average Delivered Electricity Price Impacts in 2026 and 2029, by State (cents/kwh)



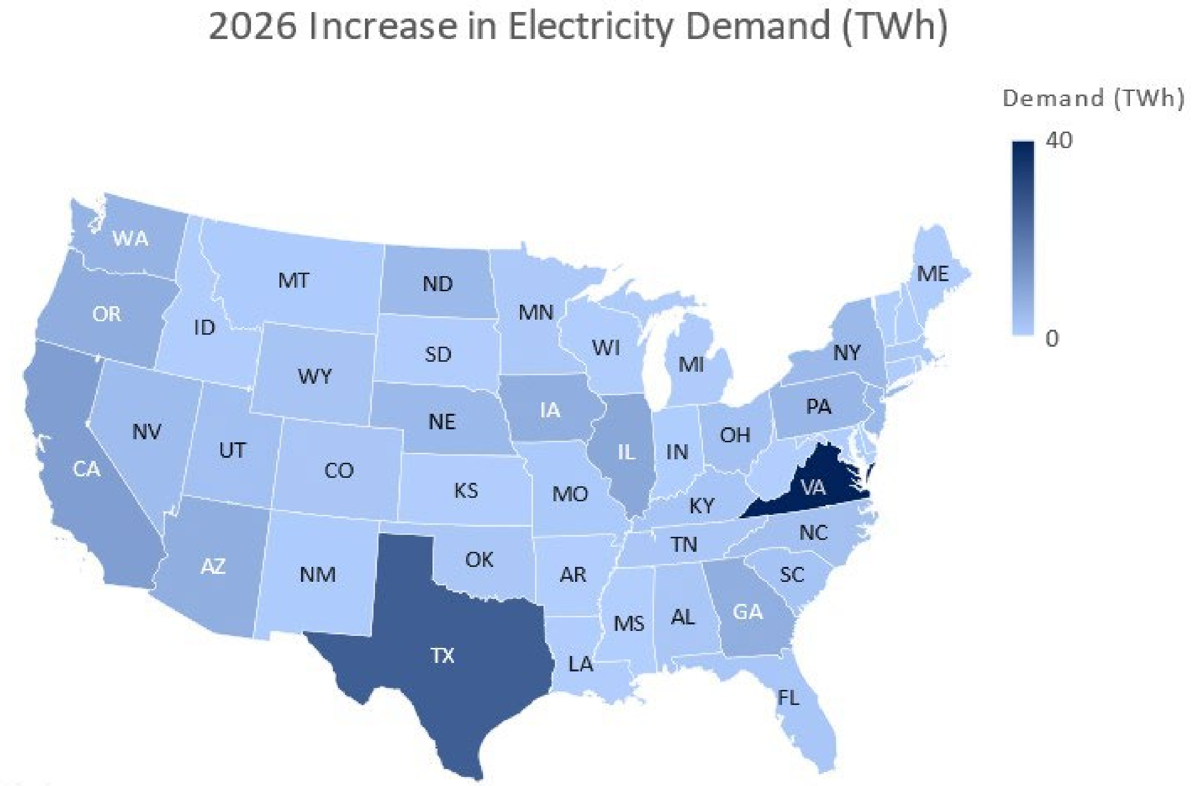


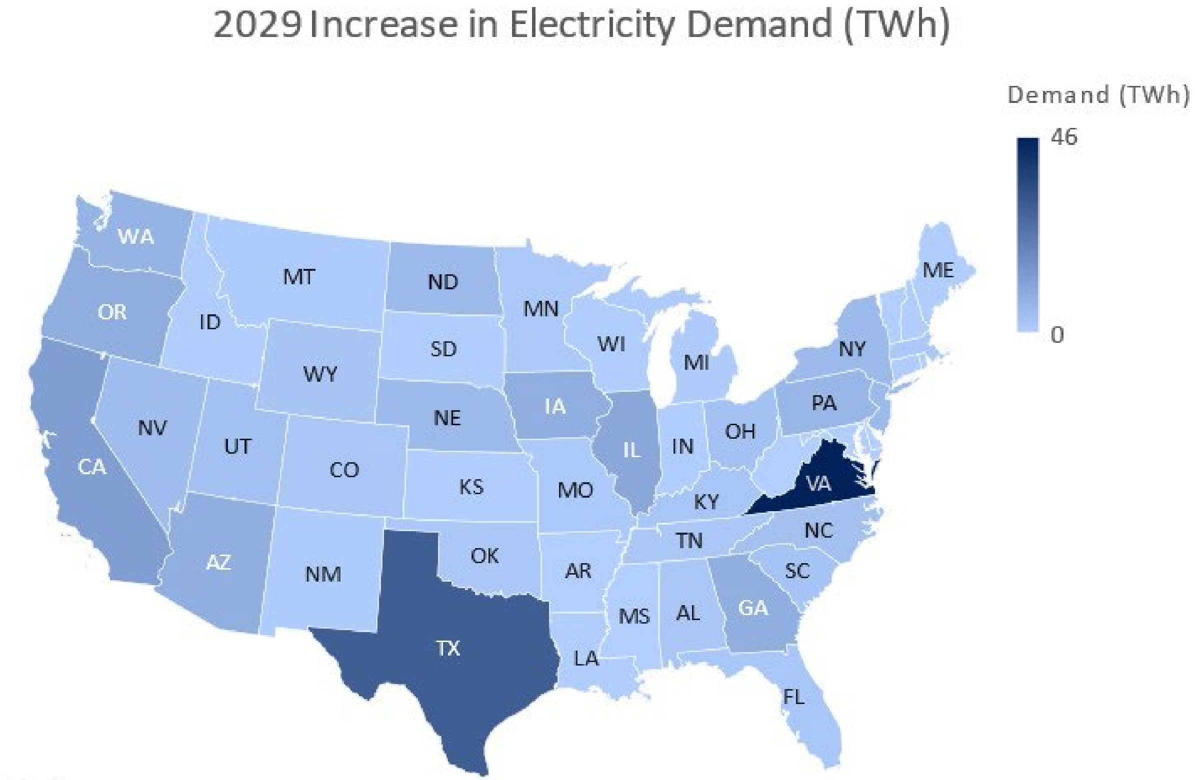
Additional Results: Increase in Electricity Demand from Data Centers





Additional Results: Increase in Electricity Demand from Data Centers





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

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%

** Prices are denominated in nominal dollars.*
*** The rank of states are different under a percentage price change and absolute price change basis due to having different electricity prices, which is the base of percentage calculations.*

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

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%

** Prices are denominated in nominal dollars.*
*** The rank of states are different under a percentage price change and absolute price change basis due to having different electricity prices, which is the base of percentage calculations.*

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

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	10.3%
DC	3.1	17.8%	CA	3.2	2.1%
WY	2.6	29.5%	RI	2.8	29.2%
NM	2.6	24.4%	NJ	2.8	24.0%
IL	2.1	17.9%	NM	2.7	25.1%
NJ	2.0	10.9%	WY	2.7	15.9%
MD	1.9	12.7%	MD	2.7	16.6%
NC	1.8	17.0%	DE	2.1	18.1%
DE	1.8	13.5%	NC	2.0	15.4%
KS	1.8	15.1%	TN	1.9	10.5%
WA	1.6	17.1%	AZ	1.8	12.0%
AZ	1.6	12.4%	MN	1.7	13.4%
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	17.9%

** Prices are denominated in nominal dollars.*
*** The rank of states are different under a percentage price change and absolute price change basis due to having different electricity prices, which is the base of percentage calculations.*

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 Oi	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

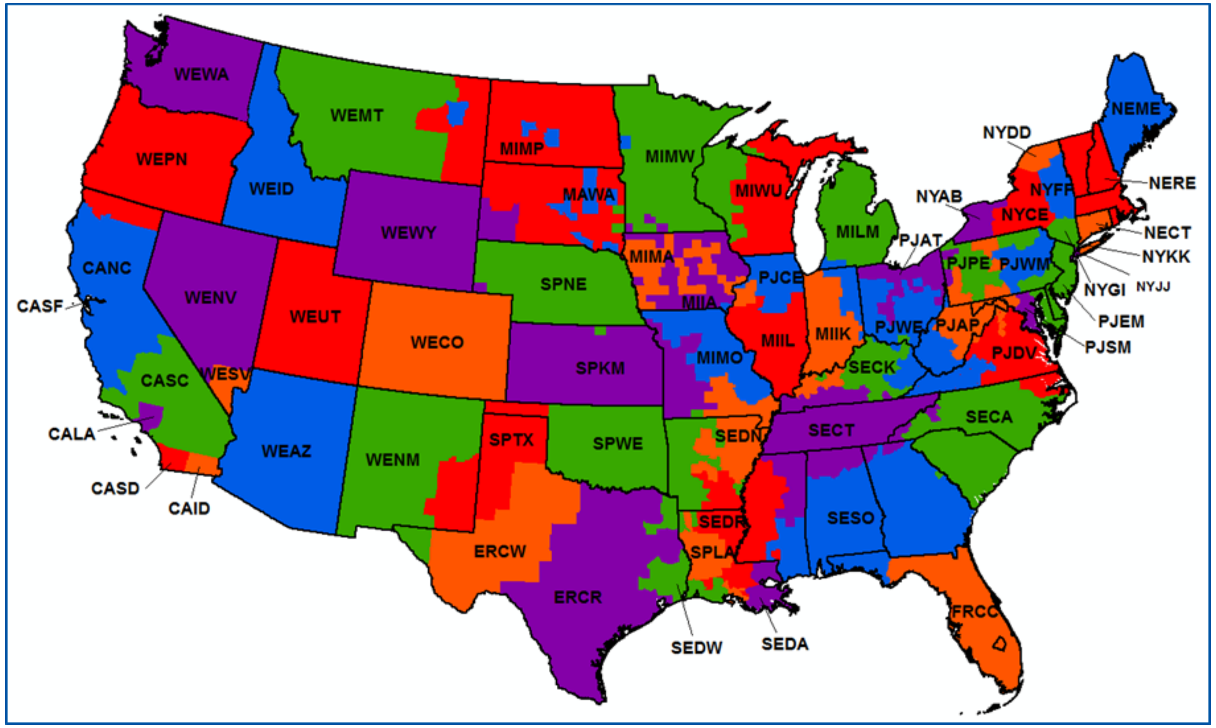
- Demand by region for 63 U.S. regions, including 11 Canadian regions (not shown in the chart). The U.S. regions include only lower-48 states.
- 25 electricity demand "load blocks"
- 10 in summer and 5 each in winter, spring, and fall
- Reflects peak vs. off-peak demand in each season
- Regional "reserve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

NewERA 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

§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.

§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.

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

About NERA

Since 1961, NERA has provided unparalleled guidance on the most important market, legal, and regulatory questions of the day. Our work has shaped industries and policy around the world. Our field-leading experts and deep experience allow us to provide rigorous analysis, reliable expert testimony, and data-powered policy recommendations for the world's leading law firms and corporations as well as regulators and governments. Our experience, integrity, and economic ingenuity mean you can depend on us in the face of your biggest economic and financial challenges.

QUALIFICATIONS, ASSUMPTIONS, AND LIMITING CONDITIONS

This report is for the exclusive use of the NERA client named herein. This report is not intended for general circulation or publication, nor is it to be reproduced, quoted, or distributed for any purpose without the prior written permission of NERA. There are no third-party beneficiaries with respect to this report, and NERA does not accept any liability to any third party.

Information furnished by others, upon which all or portions of this report are based, is believed to be reliable but has not been independently verified, unless otherwise expressly indicated. Public information and industry and statistical data are from sources we deem to be reliable; however, we make no representation as to the accuracy or completeness of such information. The findings contained in this report may contain predictions based on current data and historical trends. Any such predictions are subject to inherent risks and uncertainties. NERA accepts no responsibility for actual results or future events.

The opinions expressed in this report are valid only for the purpose stated herein and as of the date of this report. No obligation is assumed to revise this report to reflect changes, events, or conditions, which occur subsequent to the date hereof.

All decisions in connection with the implementation or use of advice or recommendations contained in this report are the sole responsibility of the client. This report does not represent investment advice nor does it provide an opinion regarding the fairness of any transaction to any and all parties. In addition, this report does not represent legal, medical, accounting, safety, or other specialized advice. For any such advice, NERA recommends seeking and obtaining advice from a qualified professional.

NERA

ECONOMICS. EXPERTS. EXPERIENCE.