

The Cost of Constraining New Solar and Wind

Prepared for Corporate Energy Buyers Association (CEBA)

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Introduction

- NERA Economic Consulting (NERA) was engaged by the Corporate Energy Buyers Association (CEBA) to examine the impacts of placing restrictions on the permitting of solar and wind projects across all regional U.S. electricity markets. Permitting restrictions on solar and wind projects were modelled as constraints on new solar and wind resource deployment.
- In this study, NERA evaluated four different scenarios taking into consideration a constrained electricity market environment in which new solar and wind resources deployment was constrained, compared to an unconstrained electricity market environment that assumes permitting neutrality in which new solar and wind resources compete based on economics with no constraints on their deployment. The scenarios assumed two different electricity demand forecasts that differ based on future incremental load growth assumptions.
- The scenarios evaluated in this study were designed to study the economics of new solar and wind deployment and their impact on the U.S. electricity market. The scenarios were not intended to represent any actual policy.
- To evaluate the electricity market impacts, NERA used its N_{ew}ERA U.S. electricity dispatch model and an electricity rate model.
- The following slides detail key electricity market results, an in-depth description of the scenarios that were evaluated, the electricity market modeling approach, the key inputs to those scenarios, and additional information about the N_{ew}ERA model.

Study Limitations and Caveats

The resulting electricity market impacts depend on model inputs and assumptions.

- **Policy Modeling:** The scenarios presented are not designed to model any specific policies.
- **Transmission Capacity:** The study assumes transmission flow limits based on the existing transmission system, with no new transmission being built during the study period. The model selects existing generation capacity and adds new capacity to meet load on an economic basis, while optimizing the utilization of the existing transmission system, accounting for factors such as inter-regional electricity flows and congestion. This assumption increases electricity prices and limits the cost-effective flow of electricity in regions where transmission lines are congested.
- **Capacity Additions:** The modeling did not incorporate real-world siting or technology-specific constraints (e.g., the availability of natural gas turbine technology or the land constraints associated with building solar resources) that might exist with respect to building new generating capacity. The model built generating capacity in regions where it deems it to be economically feasible while satisfying electricity market constraints.
- **Fixed Demand and Fuel Prices:** The study did not model economic feedback of the changes in the electricity market under the various scenarios on electricity demand or on the fuel prices.
- **Tax Incentives:** The tax incentives for clean energy resources modeled for the future are based on U.S. Energy Information Administration (EIA) policy assumptions and assumed that they are realized in the future.

Key Insights from the Study

- **Regional electricity price impacts from constraining solar and wind vary:**
 - Electricity prices increase by as much as 22% across regions, with the largest increases observed in ERCOT (22%), NYISO (11%) and the West Region (9%) when solar and wind resource deployment is constrained.
 - For ERCOT, the annual average increase in electricity costs from 2027-2033 amount to about \$3 billion, with \$21 billion in total cumulative increase over the seven-year period. Household increase are on average \$1 billion per year or \$7 billion on a cumulative basis, while commercial and industrial (C&I) customers increase are on average \$2 billion per year or \$14 billion on a cumulative basis over the seven-year period.
 - When new solar and wind resources are constrained, average U.S. electricity prices are higher by as much as \$2.3/MWh (6%) from 2027–2033.
- **Constraining solar and wind resource deployment raises U.S. household natural gas and electricity costs:**
 - From 2027–2033, economy-wide household energy costs increase on average by \$11.6 billion annually from constraining solar and wind resource deployment; amounting to about \$81.2 billion in total incremental cumulative energy expenditure over the seven-year period.
 - The economy-wide natural gas and electricity price impacts for households from constraining solar and wind resource deployment translates to an estimated \$8.0 billion and \$3.6 billion (\$11.6 billion) increase in annual average household natural gas and electricity expenditures, respectively from 2027-2033.

Key Insights from the Study (2)

- **When new solar and wind are not constrained, there is significant economic deployment of lowest-cost new capacity**
 - From 2027-2033, across the modeled scenarios that incorporate permitting neutrality:
 - Cumulative solar and onshore wind capacity additions range from 135-143 GW and 274-297 GW, respectively.
 - Cumulative solar with storage and onshore wind with storage capacity additions are about 1 GW and 41–42 GW, respectively.
- **Increased reliance on natural gas capacity and generation raises reliability risks and increases exposure to price volatility:**
 - Constraining solar and wind deployment necessitates natural gas capacity additions that are 60% to 72% above EIA projections through 2033. Industry literature also highlights risks from constrained gas turbine supply and high costs, potentially limiting reliance on natural gas to meet projected load.
 - Constraining solar and wind deployment also heightens exposure to natural gas fuel price volatility and creates a less diverse electricity generation mix during peak hours raising reliability risks.
- **Electricity price increases from load growth could be reduced with permitting neutrality:**
 - Allowing deployment of low-cost solar and wind resources helps mitigate the pressure from electricity price increases arising from load growth.

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Overview of Scenarios, Regions and Results Analyzed

Scenarios Analyzed to Evaluate Electricity Market Impacts

Four scenarios were analyzed for the study to assess the impacts from the economic deployment of solar and wind resources and future incremental load growth assumptions.

- The study evaluated four scenarios with and without new solar and wind resource deployment and two different electricity demand forecasts to assess the electricity market impacts of placing restrictions on the permitting of solar and wind projects. Restrictions on the permitting of solar and wind projects are modelled as constraints placed on new solar and wind resource deployment.

Scenario	Scenario Name	Constrain Wind/Solar Deployment	Data Center Electricity Demand	Scenario Description
Scn1	Allow Wind/Solar	No	Business-as-usual (EIA AEO 2026)	Economic deployment of wind/solar resources*, business-as-usual electricity demand with no constraints on technology deployment (permitting neutrality).
Scn2	Allow Wind/Solar w/ High Demand	No	High (EPRI Medium Growth)	Economic deployment of wind/solar resources*, high electricity demand with no constraints on technology deployment (permitting neutrality).
Scn3	Constrain Wind/Solar	Yes	Business-as-usual (EIA AEO 2026)	Constrain wind/solar resource deployment and business-as-usual electricity demand.
Scn4	Constrain Wind/Solar w/ High Demand	Yes	High (EPRI Medium Growth)	Constrain wind/solar resource deployment and high electricity demand.

Note: The modeled scenarios do not incorporate state RPS and CES mandates.

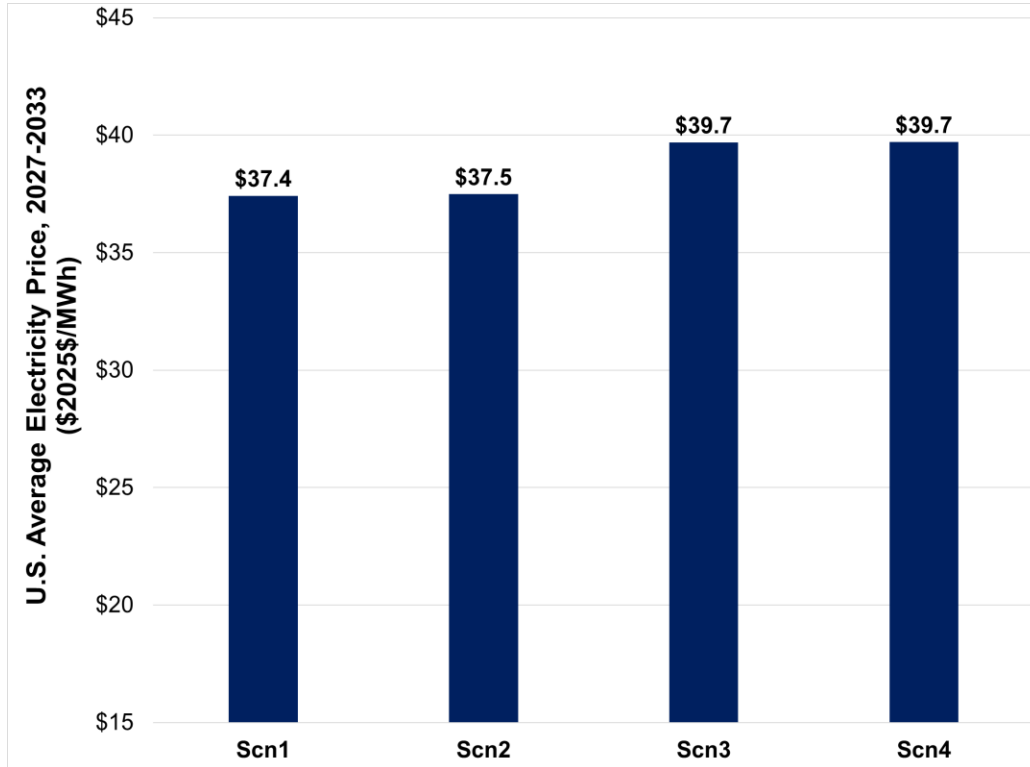
* Includes planned resource builds for solar and wind.

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Summary of National and Regional Electricity Market Impacts

National Average Electricity Prices Are Influenced by Supply and Demand Pressures

At the national level, constraining solar and wind raises average electricity prices.



Note: Scn1 - Allow Wind/Solar; Scn2 - Allow Wind/Solar w/ High Demand; Scn3 - Constrain Wind/Solar; Scn4 - Constrain Wind/Solar w/ High Demand.

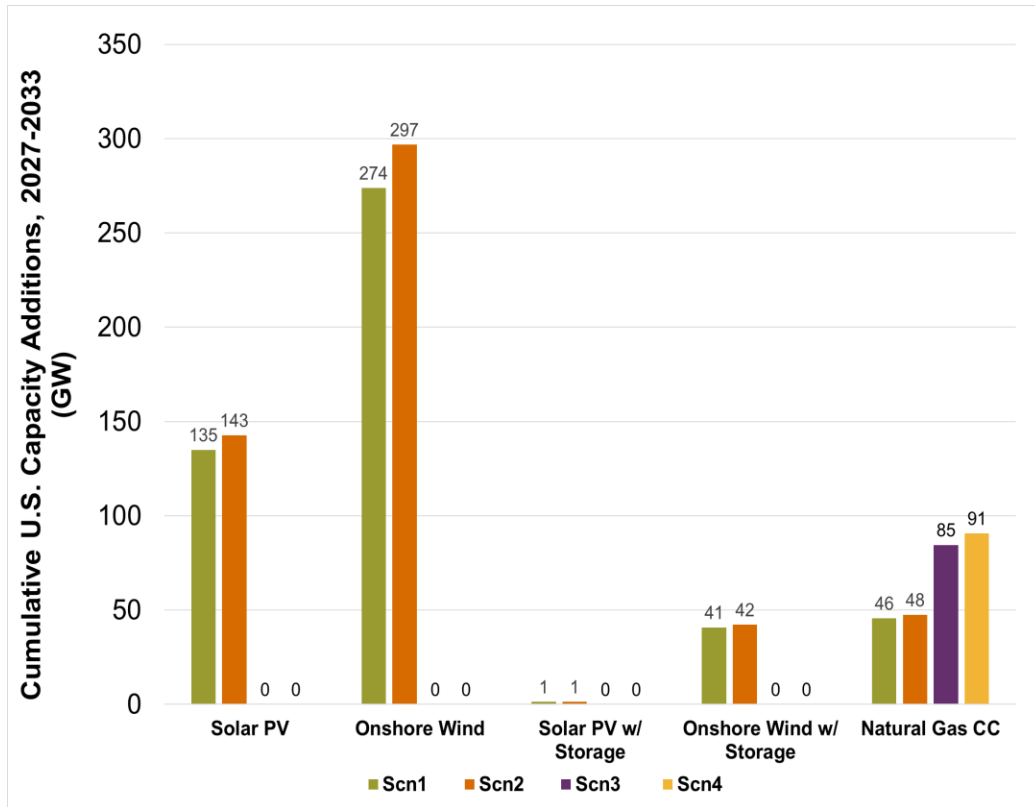
The electricity prices reported are delivered residential electricity prices that is net of the T&D margin.

Y-axis begins from \$15/MWh for ease of visual depiction.

- On average from 2027-2033 for the U.S., electricity prices are higher by 5.9-6.1% in Scn3 and Scn4 compared to Scn1 and Scn2, respectively.
- In competitive regions, electricity price changes are driven by the wholesale costs (which are higher when solar and wind deployment are constrained)
 - Across all competitive regions, electricity prices are higher by 10-11% in Scn3 and Scn 4 compared to Scn1 and Scn2, respectively.
- In cost-of-service (COS) regions, electricity price changes are driven by the incremental cost-of-service (fuel and operating costs, new build costs). The incremental cost of building solar and wind in cost-of-service regions raise prices, offset partially by lower fuel costs and new build costs from lower natural gas combined cycle (CC) builds.
 - Across all COS regions, electricity prices are higher by about 2.9-3.3% in Scn3 and Scn 4 compared to Scn1 and Scn2.
- A higher electricity demand forecast also induces more deployment of solar and wind when allowed, resulting in only a modest increase in electricity prices.
 - On average from 2027-2033, prices are greater by as much as 0.2% in scenarios with higher demand (Scn2, Scn4) compared to the scenarios with default business-as-usual electricity demand (Scn1, Scn3).
 - The demand pressure induces more wind and solar deployment, decreasing overall system wholesale costs in competitive regions leading to a 0.7-1.6% electricity price decrease while resulting in higher incremental cost-of-service in COS regions leading to a 0.6-0.9% electricity price increase.

National Solar and Wind Deployment Increase When Economic Uptake is Permitted

When solar and wind are constrained, their national deployment decreases, with natural gas capacity added across all scenarios.

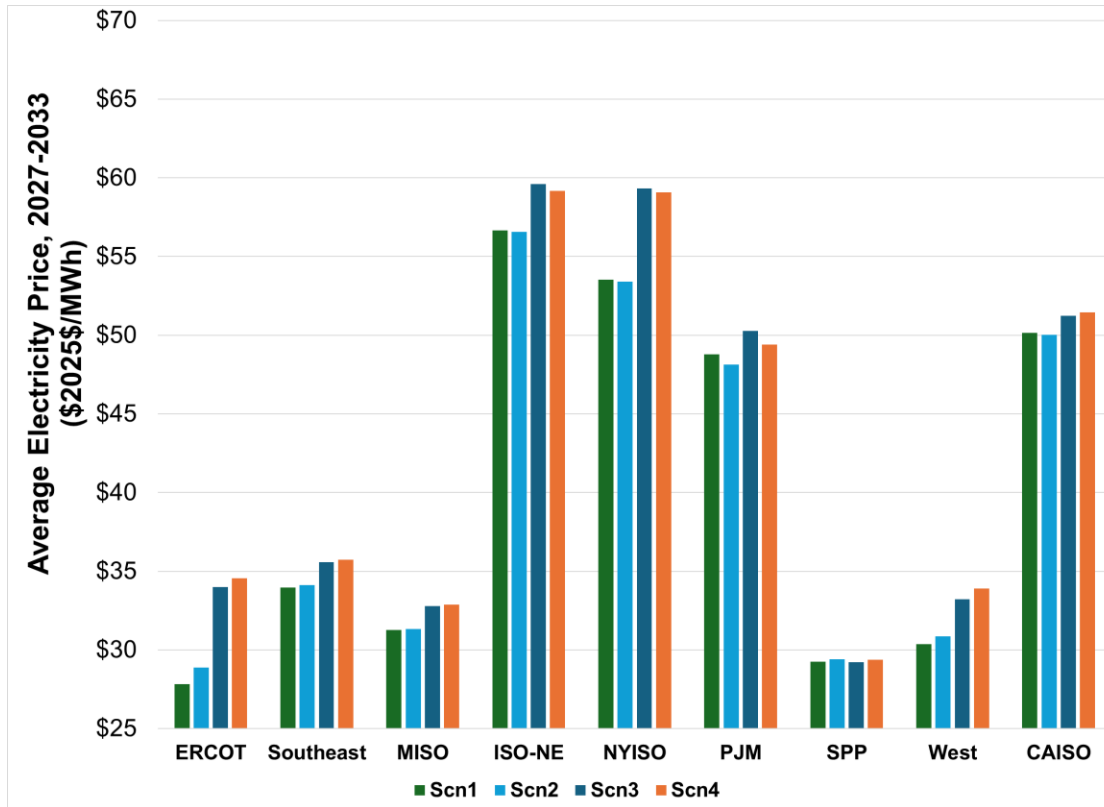


Note: Scn1 - Allow Wind/Solar; Scn2 - Allow Wind/Solar w/ High Demand; Scn3 - Constrain Wind/Solar; Scn4 - Constrain Wind/Solar w/ High Demand.

- From 2027-2033, when solar and wind resources are constrained,
 - Solar PV additions in the U.S. are lower as much as 143 GW.
 - Onshore wind additions in the U.S. are lower by as much as 297 GW.
 - Solar PV w/ storage additions in the U.S. are lower by as much as 1 GW.
 - Onshore wind w/ storage additions in the U.S. are lower by as much as 42 GW.
 - New natural gas CC capacity continues to be built under all scenarios.
 - Modest decreases in standalone storage (< 1 GW) are observed above the current planned additions.

Average Electricity Price Impacts Vary Across Regions

ERCOT and NYISO see the largest increase in average electricity prices when the economic deployment of solar and wind resources are constrained.



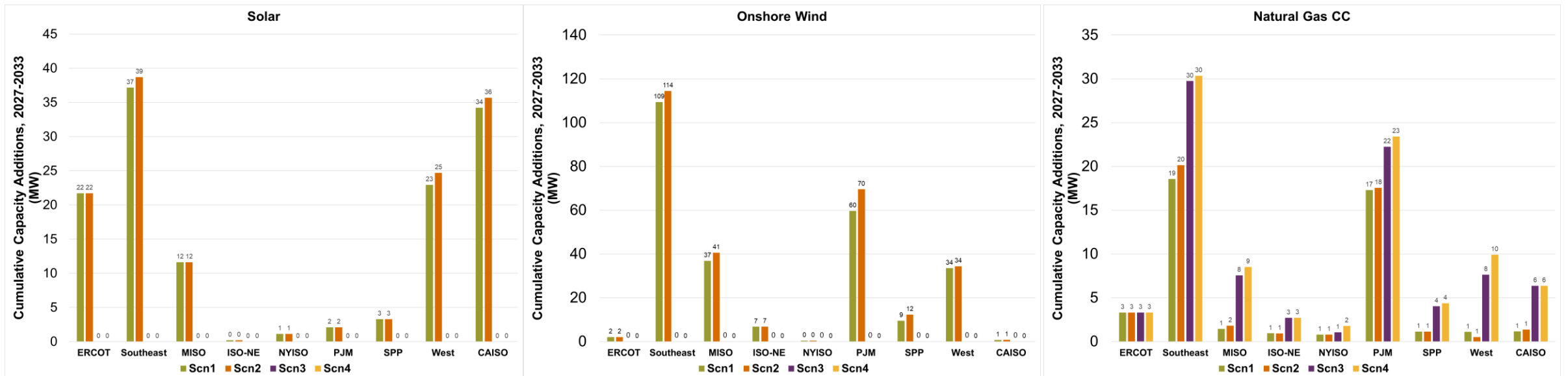
- On average from 2027-2033,
 - ERCOT and NYISO experience the largest increase in electricity prices in scenarios when solar and wind deployment is constrained (Scn3 and Scn4) compared to scenarios when solar and wind resource deployment is allowed (Scn1 and Scn2):
 - In, ERCOT and NYISO electricity prices increase by as much as 22% and 11%, respectively.
- The largest regional increase in electricity prices from demand pressures is observed in ERCOT (~4%) and the West (~2%) (Scn2 and Scn4 compared to Scn1 and Scn3).

Note: Scn1 - Allow Wind/Solar; Scn2 - Allow Wind/Solar w/ High Demand; Scn3 - Constrain Wind/Solar; Scn4 - Constrain Wind/Solar w/ High Demand.
The electricity prices reported are delivered residential electricity prices that is net of the T&D margin.
Y-axis begins from \$25/MWh for ease of visual depiction.

Solar, Wind, and Natural Gas CCs Are Cost-Effective Across All Scenarios and Regions

Constraining solar and wind decreases their deployment across all regions.

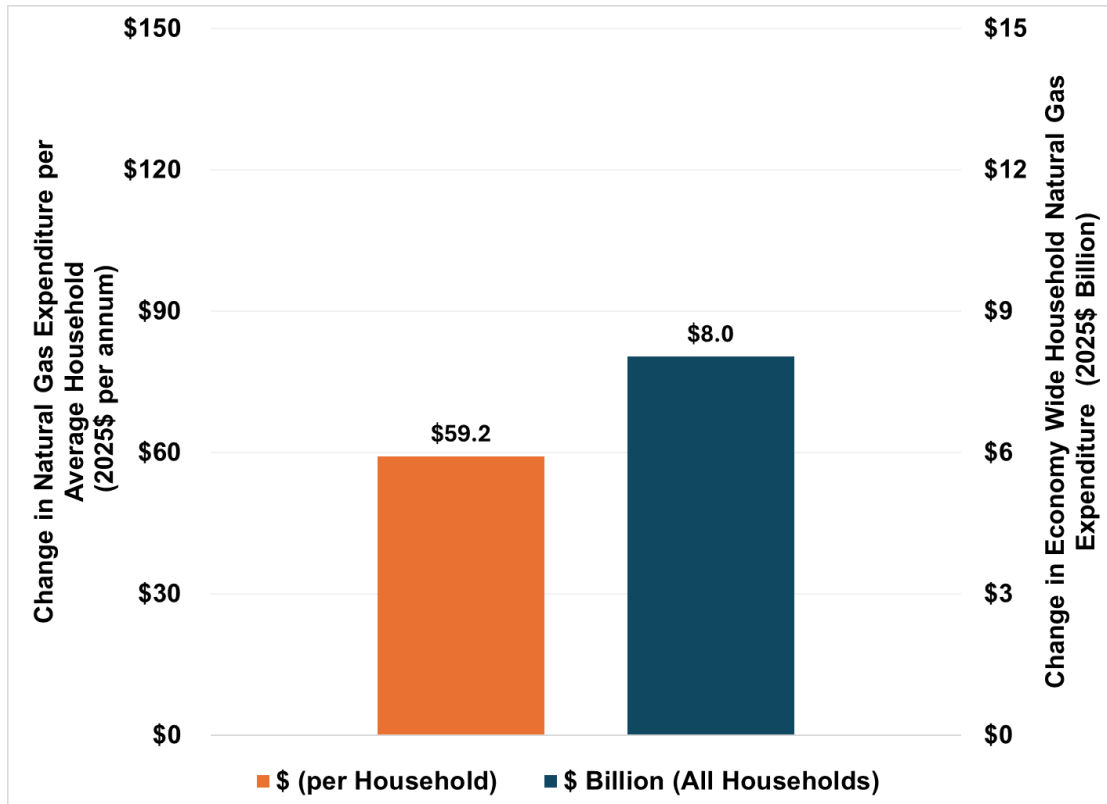
- Under scenarios that constrain the economic deployment of solar and wind:
 - Solar PV deployment is lowered by the most in CAISO, Southeast and the West.
 - Onshore wind deployment is lowered by most in the Southeast, MISO, and PJM.
 - Natural gas CC deployment increases by the most in PJM and the Southeast.



Note: Scn1 - Allow Wind/Solar; Scn2 - Allow Wind/Solar w/ High Demand; Scn3 - Constrain Wind/Solar; Scn4 - Constrain Wind/Solar w/ High Demand.

Constraining Deployment of Solar and Wind Resources Increases Natural Gas Expenditures for Households

From 2027–2033, constraining solar and wind deployment increases national average household natural gas costs by about \$59 annually and raises economy-wide natural gas household costs by approximately \$8 billion annually.



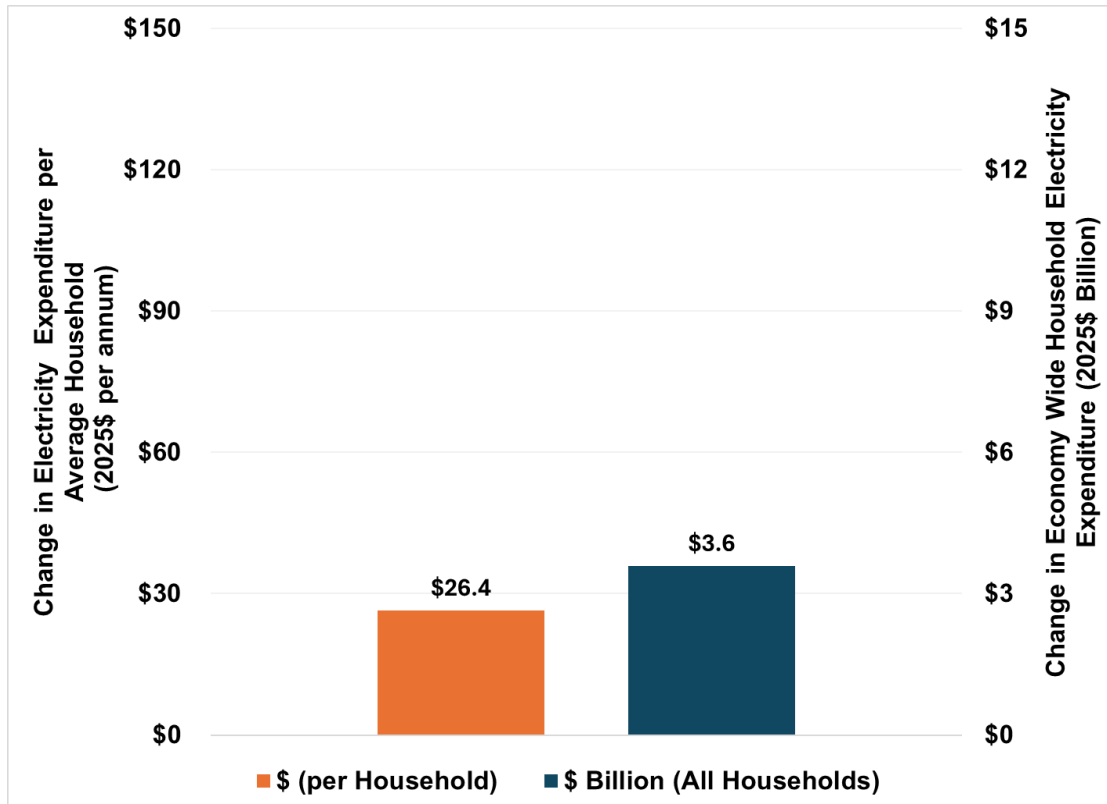
- Based on the 2024 CEX, the natural gas expenditure for a representative U.S. household is assumed to be \$508 per annum.^[1]
- The natural gas price impacts are estimated using a natural gas price elasticity estimate calculated using natural gas price and electric sector natural gas demand changes from AEO 2026.
 - The natural gas price increase is estimated by first calculating changes in the total economy-wide natural gas demand (for Scn3 and Scn 4 compared to Scn1 and Scn2).
 - The natural gas demand elasticity is then applied to these changes to calculate the natural gas price impacts.
 - These impacts are then applied to natural gas expenditure estimate (drawn from the CEX) to estimate the cost impacts for natural gas.
- If solar and wind resource deployment is constrained, each household is estimated to experience a \$59 increase per year in natural gas expenditure with the economy-wide increase in household natural gas expenditure estimated to be about \$8.0 billion.
- Over the next seven years (2027-2033), assuming 2024 natural gas expenditure levels, the total economy-wide incremental cumulative natural gas expenditure for households is estimated to be about \$48 billion.

[1] Table 1101. Quintiles of income before taxes: Annual expenditure means, shares, standard errors, and relative standard errors, Consumer Expenditure Surveys, 2024.

Note: NERA's estimates of the natural gas expenditure impacts assume that full natural gas price changes are passed through to consumers. Based on the 2024 CEX, the total number of households for NERA's calculations are assumed to be 135.76 million to estimate economy-wide impacts. The impacts estimated are relative to 2024 base year expenditure.

Constraining Deployment of Solar and Wind Resources Increases Electricity Expenditure for Households

From 2027–2033, constraining solar and wind deployment raises national average household electricity costs by about \$26 annually and increases economy-wide electricity household costs by approximately \$3.6 billion annually.



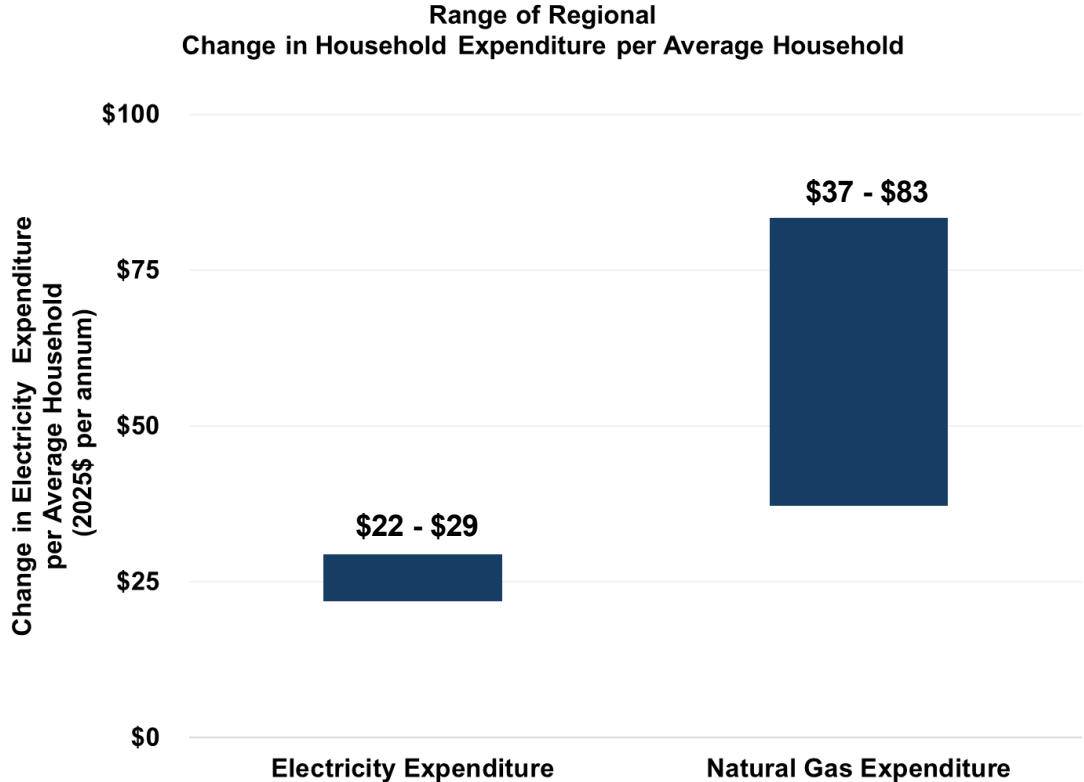
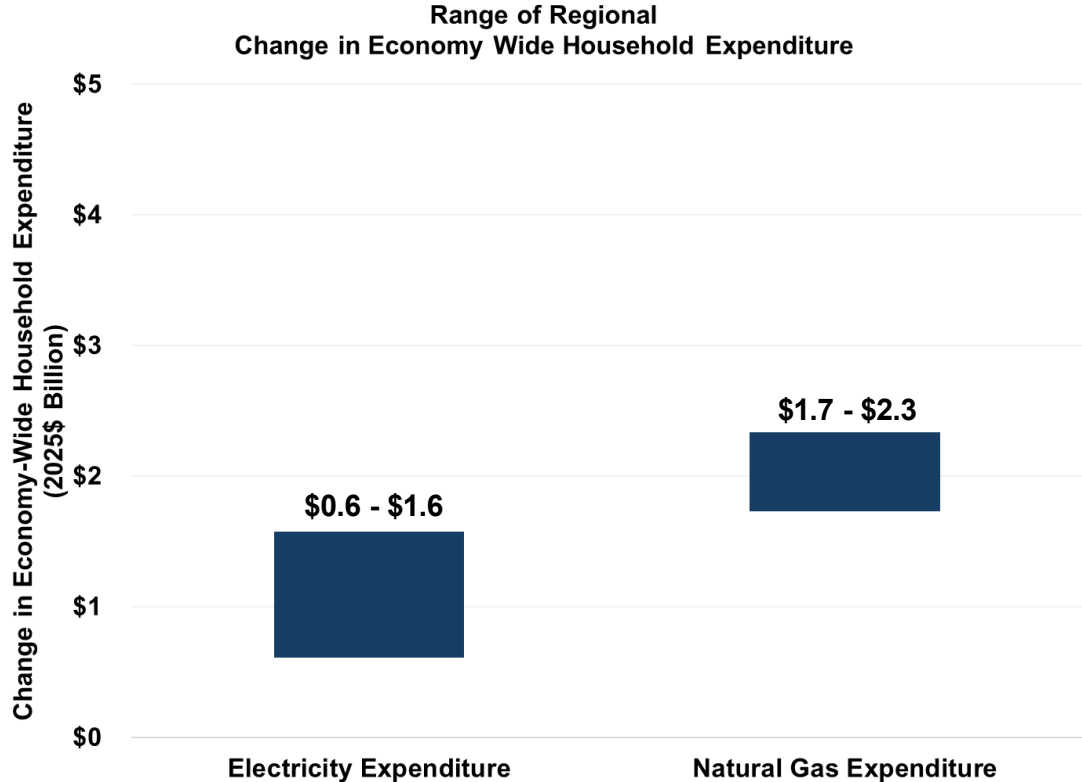
- Based on the 2024 CEX, the electricity expenditure for a representative U.S. household is assumed to be \$1,888 per annum.^[1]
- The electricity price impacts are estimated using the U.S. average residential delivered electricity prices produced from NERA’s rate model (for Scn3 and Scn 4 compared to Scn1 and Scn2).
- These price impacts are then applied to the 2024 CEX estimate for electricity expenditure for a representative U.S. household to estimate the electricity expenditure impacts per household and for the economy.
- If solar and wind resource deployment is constrained, each household is estimated to experience an increase of about \$26 per year in electricity expenditure with the economy-wide increase in household electricity expenditure estimated to be about \$3.6 billion.
- Over the next seven years (2027-2033), assuming 2024 electricity expenditure levels, the total economy-wide incremental cumulative electricity expenditure for households is estimated to be about \$21.6 billion.

[1] Table 1101. Quintiles of income before taxes: Annual expenditure means, shares, standard errors, and relative standard errors, Consumer Expenditure Surveys, 2024. <https://www.bls.gov/cex/tables.htm>

Note: NERA’s estimates of the electricity expenditure impacts assume that full electricity price changes are passed through to consumers holding electricity demand constant. Based on the 2024 CEX, the total number of households for NERA’s calculations are assumed to be 135.76 million to estimate economy-wide impacts.

Household Electricity and Natural Gas Expenditure Impacts Vary Across the U.S.

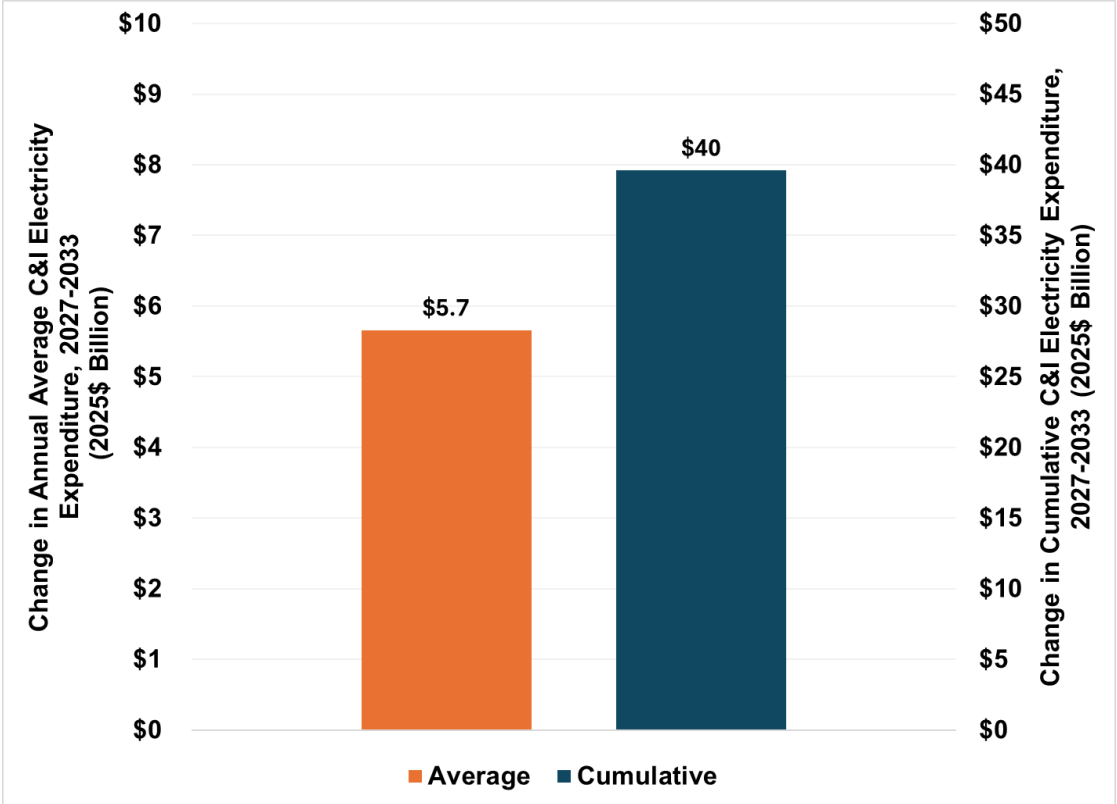
Total annual household electricity and natural gas expenditures impacts depend upon the price changes and base year expenditures. As shown in subsequent slides, the South region faces the highest annual electricity impact and the lowest annual natural gas impact because of its expenditure pattern.



Note : Natural gas expenditure impacts are based on national natural gas price changes. The regional range is presented across 4 Census regions – Northeast, Midwest, South, and West. Regional annual expenditure on electricity and natural gas varies between \$1,560-\$2,100 and \$320-\$720, respectively. (Table 1800. Region of residence: Annual expenditure means, shares, standard errors, and relative standard errors, Consumer Expenditure Surveys, 2024, available at <https://www.bls.gov/cex/tables/calendar-year/mean-item-share-average-standard-error/cu-region-1-year-average-2024.xlsx>)

Constraining Deployment of Solar and Wind Resources Increases Electricity Expenditures for C&I Consumers

From 2027-2033, economy-wide Commercial and Industrial (C&I) customers' electricity costs increase on average by about \$5.7 billion annually by constraining solar and wind resource deployment; amounting to about \$40 billion in total incremental cumulative electricity expenditure over the seven-year period.

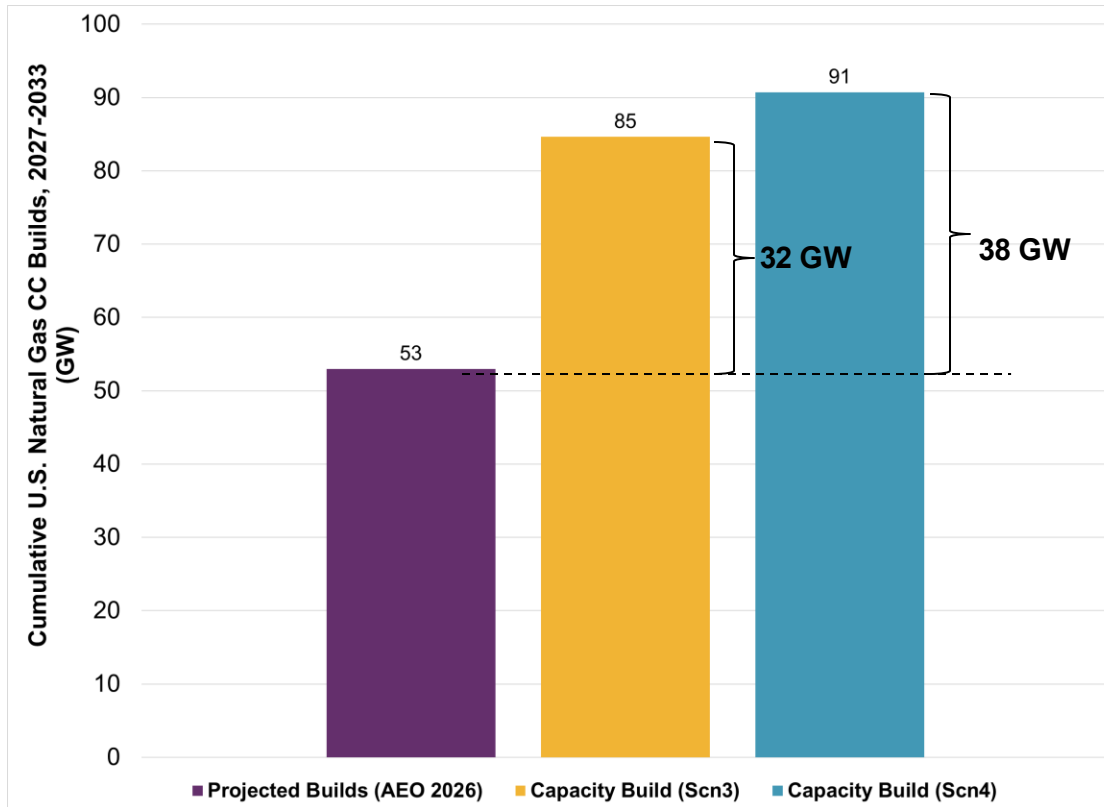


- The electricity cost impacts are estimated using the U.S. average C&I delivered electricity prices produced from NERA's rate model for the different model scenarios.
- The electricity prices from 2027-2033 are multiplied with the C&I sales for each of the corresponding years to estimate the electricity costs for C&I customers.
- The electricity costs estimated for Scn1 and Scn2 are subtracted from the electricity costs for Scn3 and Scn4, respectively to determine the increase in costs from constraining solar and wind deployment.
 - On average across Scn3 and Scn4 (compared to Scn1 and Scn2), electricity costs for C&I customers are higher by about \$5.7 billion on average from 2027-2033 and \$40 billion on a cumulative basis over the seven-year period.

Note: Scn1 - Allow Wind/Solar; Scn2 - Allow Wind/Solar w/ High Demand; Scn3 - Constrain Wind/Solar; Scn4 - Constrain Wind/Solar w/ High Demand.

Constraining Solar and Wind Deployment Leads to an Increased Reliance on Natural Gas CC Builds Raising Potential Near-term Reliability Risks

Constraining solar and wind deployment drives national natural gas CC build-outs well above EIA AEO 2026 projections.



Note: Scn3 - Constrain Wind/Solar; Scn4 - Constrain Wind/Solar w/ High Demand.

- Cumulative natural gas CC builds from 2027-2033 exceed EIA's AEO 2026 projections by 32 GW (60%) and 38 GW (72%) in Scn3 and Scn4, respectively.
- Significant supply chain issues exist for natural gas CC turbine procurement resulting from data center expansion fueled by AI and cloud computing workloads^[1] ~ 58 GW from 2025 through 2030.^[2]
- Many advanced turbines are effectively sold-out years in advance, with manufacturing slots booked into the late 2020s.^{[3], [5]}
- The costs of gas turbines are significantly higher than their costs estimated during planning ~ 36% higher than expected.^[4]

[1] Kansas Municipal Energy Agency, "Data Center Growth Strains Gas Turbine Supply as Prices Surge Through 2027", April 2, 2026. Available at: <https://kmea.com/data-center-growth-strains-gas-turbine-supply-as-prices-surge-through-2027/>.

[2] Wood Mackenzie, "Coal and gas generation can accommodate 40 to 75% of expected US peak demand growth through 2030", November 20, 2025, available at <https://www.woodmac.com/press-releases/coal-and-gas-generation-can-accommodate-40-to-75-of-expected-us-peak-demand-growth-through-2030/>.

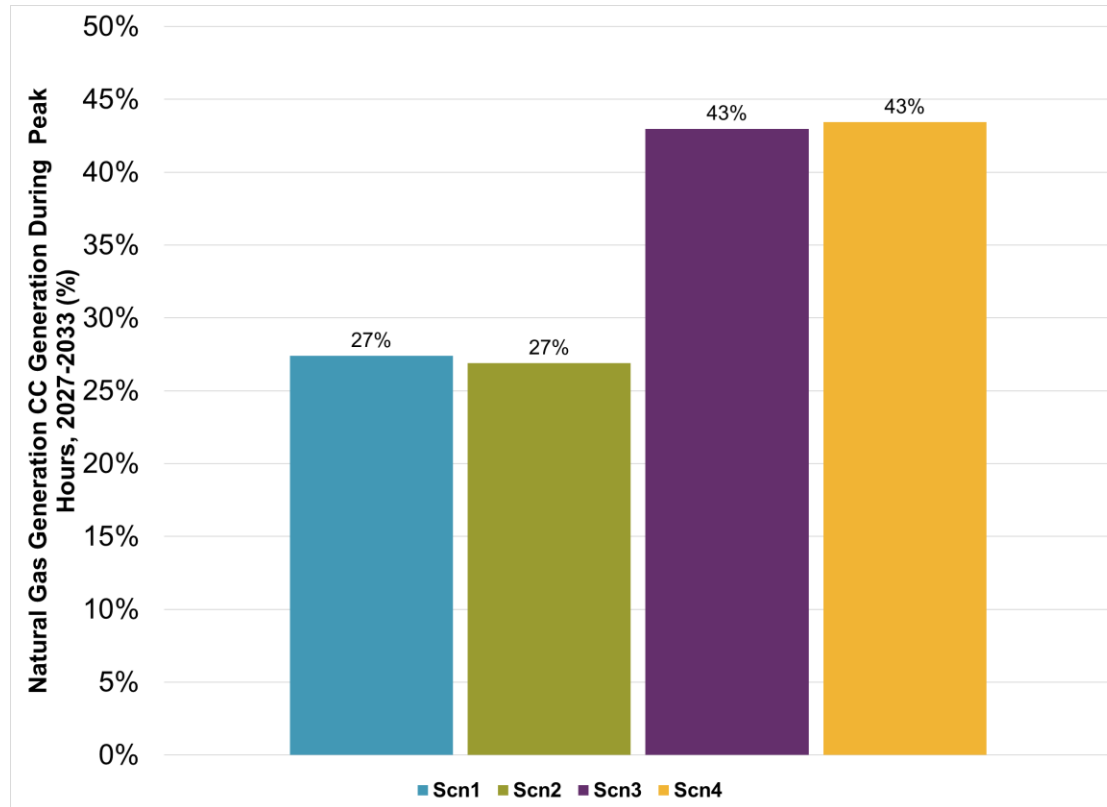
[3] PennState Institute of Energy and the Environment, "Why gas turbines are in short supply — just as the grid needs them most", February 18, 2026. Available at: <https://iee.psu.edu/news/blog/why-gas-turbines-are-short-supply-just-grid-needs-them-most>.

[4] RMI, "Gas Turbine Supply Constraints Threaten Grid Reliability; More Affordable Near-Term Solutions Can Help", June 18, 2025. Available at: <https://rmi.org/gas-turbine-supply-constraints-threaten-grid-reliability-more-affordable-near-term-solutions-can-help/>.

[5] Dive Brief, "Gas turbine supply crunch set to raise prices 195% by 2027: WoodMac" April 9, 2026. Available at: <https://www.utilitydive.com/news/gas-turbine-supply-crunch-set-to-raise-prices-195-by-2027-woodmac/816904/>.

Constraining Solar and Wind Deployment Leads to Less Diverse Electricity Generation Mix During Peak Hours

Constraining solar and wind deployment increases the share of peak-hour generation supplied by natural gas CC units, resulting in a less diversified generation mix.



- Under the scenarios when solar and wind deployment is constrained (Scn3 and Scn4), nearly half (about 43%) of total generation during the peak hours is being met by natural gas CC generation.^[1]
- The generation share decreases to about 27% in the scenarios where the economic deployment of solar and wind resources is allowed (Scn1 and Scn2).
- Allowing solar and wind resource deployment results in greater diversification of generating resources to meet the demand compared to scenarios that constrain the economic deployment of solar and wind.

Note: Scn1 - Allow Wind/Solar; Scn2 - Allow Wind/Solar w/ High Demand; Scn3 - Constrain Wind/Solar; Scn4 - Constrain Wind/Solar w/ High Demand.

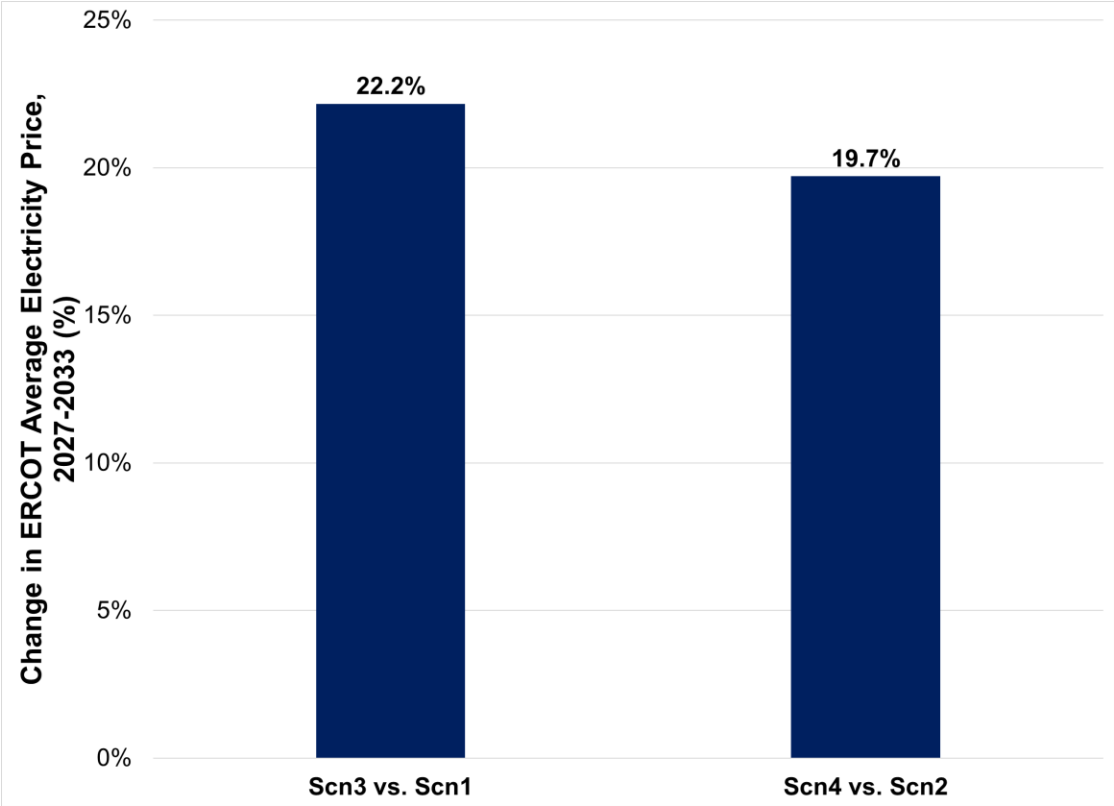
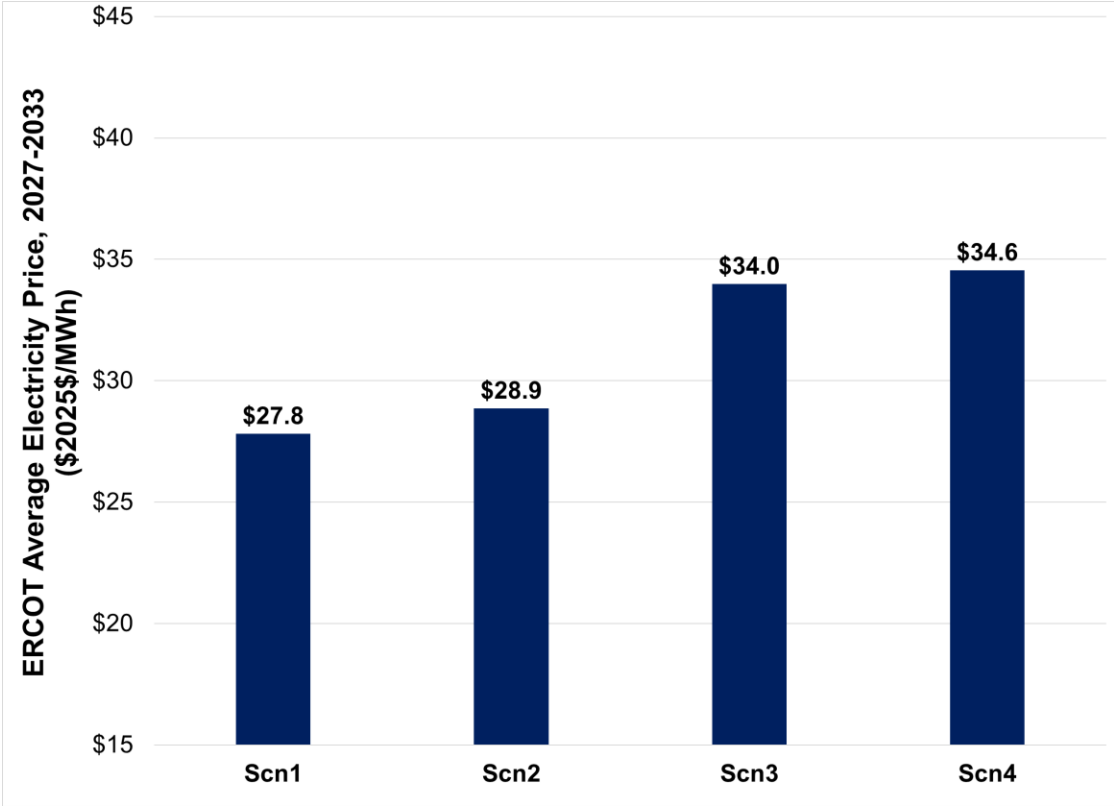
^[1] Annual Electricity demand in the model is aggregated into 25 load blocks. The seasonal peak hours in the model are represented in four of these load blocks, one for each of the seasons with a total of 170 hours across these four blocks or about 2% of the total number of hours in a year.

3

Summary of Electricity Market Impacts: Additional Regional Results

ERCOT Region: Key Results

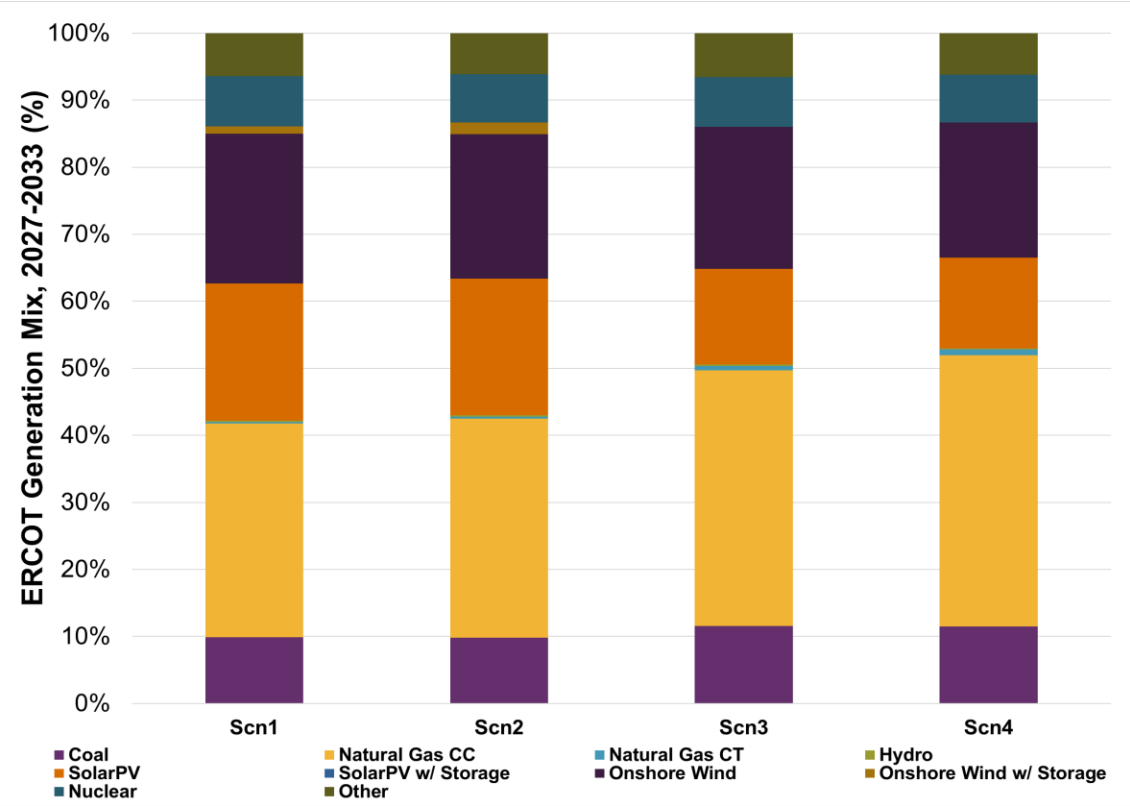
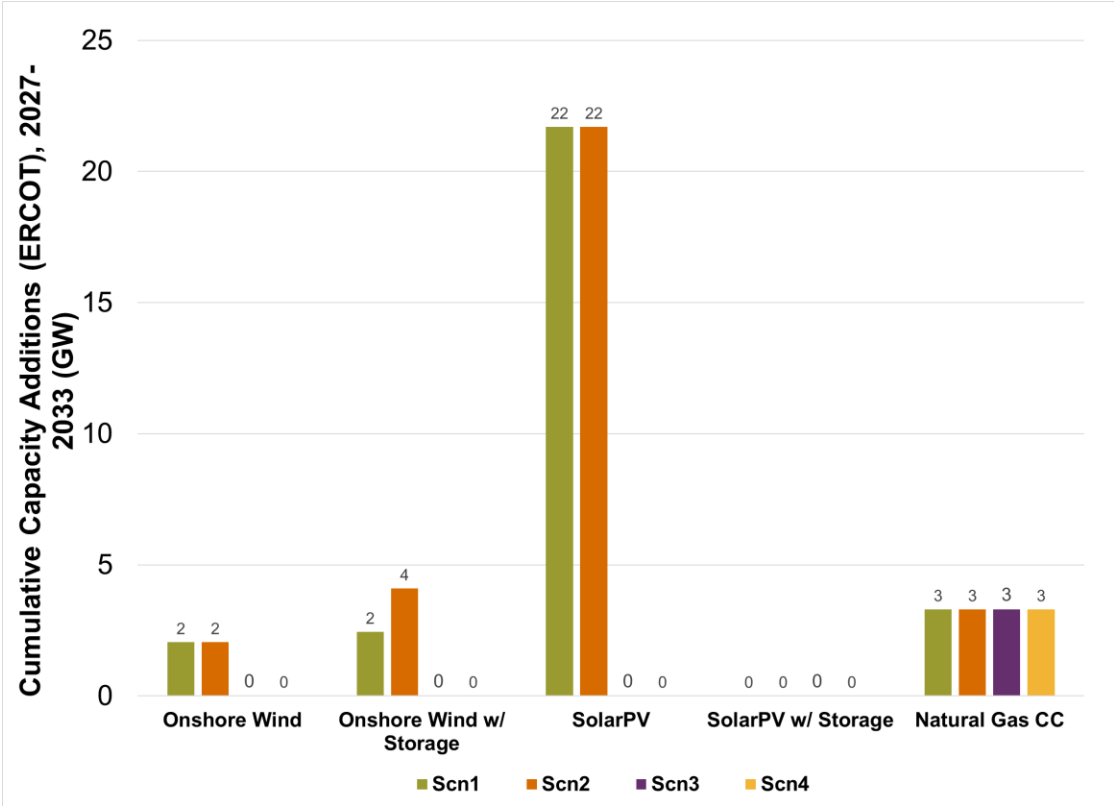
Electricity prices in ERCOT are 20–22% higher when solar and wind deployment is constrained driven primarily by the absence of solar deployment, with the additional demand pressure from the higher electricity demand in Scn2 and Scn4 leading to a modest increase in electricity prices compared to the corresponding scenarios without the higher electricity demand.



Note: Scn1 - Allow Wind/Solar; Scn2 - Allow Wind/Solar w/ High Demand; Scn3 - Constrain Wind/Solar; Scn4 - Constrain Wind/Solar w/ High Demand. The electricity prices reported are delivered residential electricity prices that is net of the T&D margin.
The Y-axis for the chart on the left begins from \$15/MWh for ease of visual depiction.

ERCOT Region: Key Results

In ERCOT, solar and wind deployment remain relatively unchanged across scenarios that allow their economic deployment (Scn1 and Scn2) with a modest increase in wind with storage builds observed in Scn2 (with higher electricity demand). Natural gas CC capacity additions also remain constant across all scenarios to meet demand, though the generation share for natural gas CCs is seen to decline when solar and wind are allowed to compete on economics.

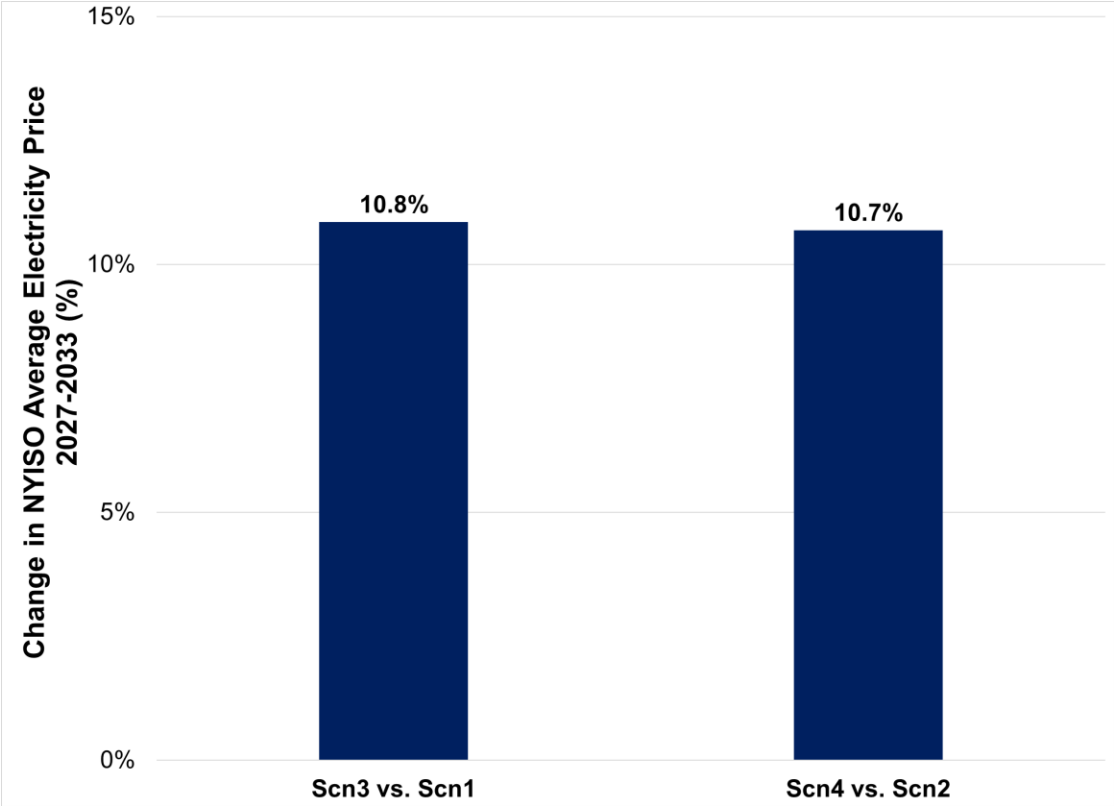
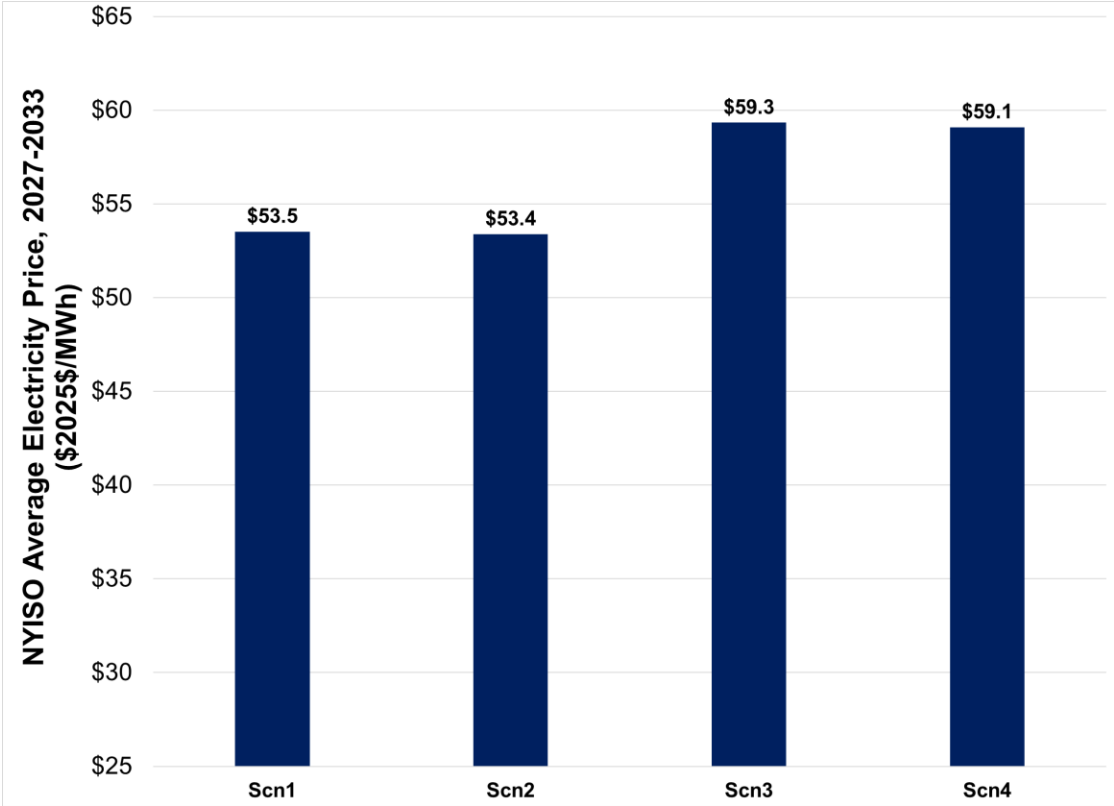


Note: Scn1 - Allow Wind/Solar; Scn2 - Allow Wind/Solar w/ High Demand, Scn3 - Constrain Wind/Solar; Scn4 - Constrain Wind/Solar w/ High Demand.

Note: Other" includes Oil CT, LFG, Battery Storage, Natural Gas CC w/ CCS, Biomass, Geothermal, Solar Thermal, Pumped Storage, MSW, Offshore Wind, and Coal w/ CC.

NYISO Region: Key Results

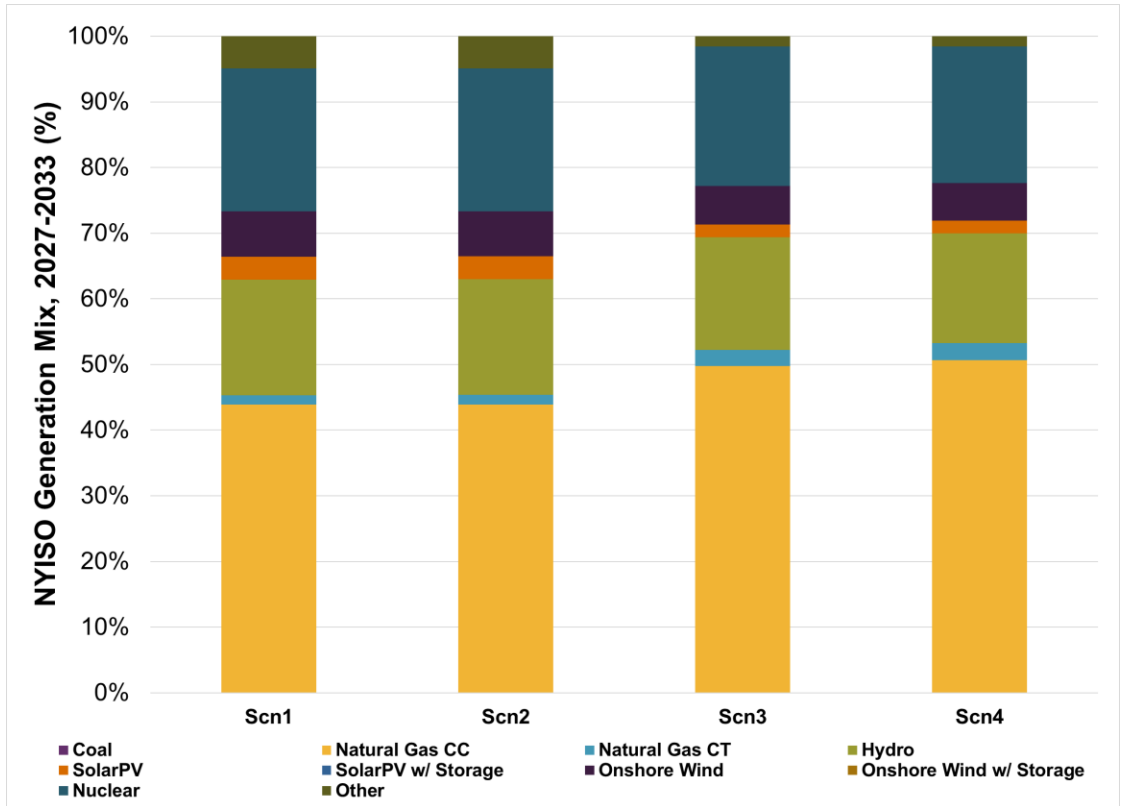
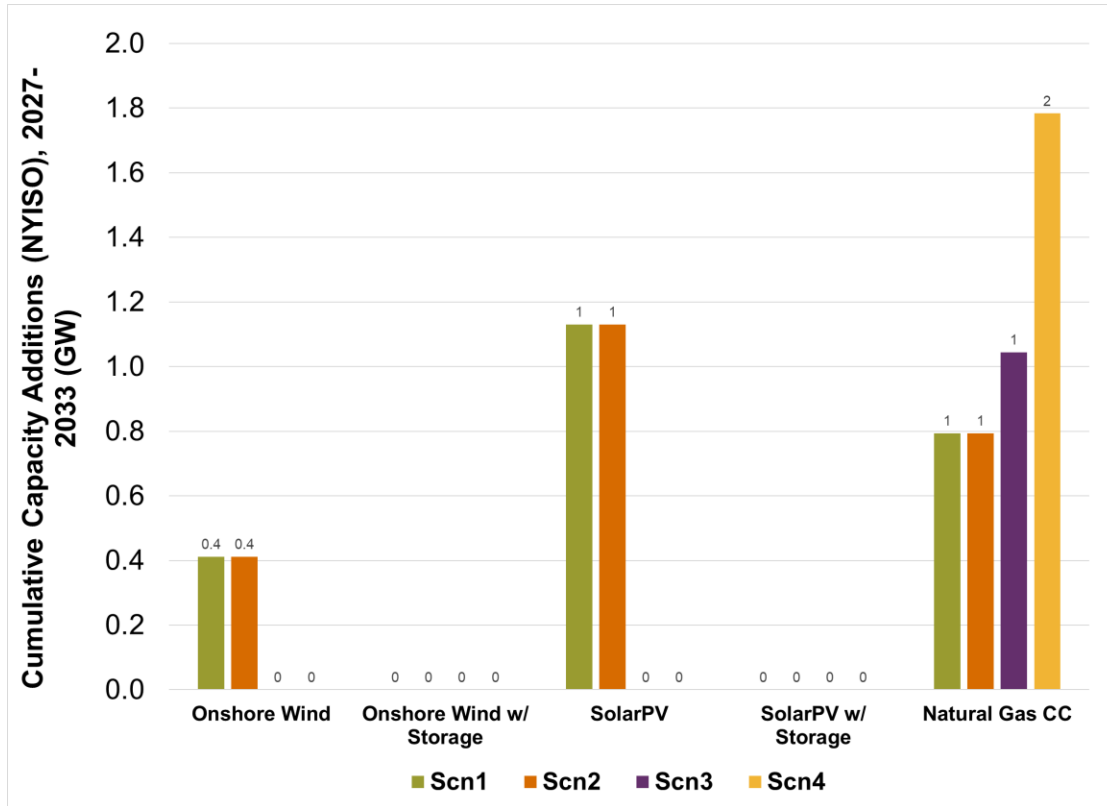
In NYISO, constraining solar and wind to compete on economics increases electricity prices by about 11%, primarily driven by a modest reduction of solar and wind resources and a modest increase in natural gas CC generation.



Note: Scn1 - Allow Wind/Solar; Scn2 - Allow Wind/Solar w/ High Demand; Scn3 - Constrain Wind/Solar; Scn4 - Constrain Wind/Solar w/ High Demand. The electricity prices reported are delivered residential electricity prices that is net of the T&D margin.
The Y-axis for the chart on the left begins from \$25/MWh for ease of visual depiction.

NYISO Region: Key Results

In NYISO, constraining solar and wind to compete on economics results in only a negligible level of solar and wind resource deployment, as existing clean firm resources (hydropower and nuclear) and natural gas CC generation continue to supply a significant share of total generation.

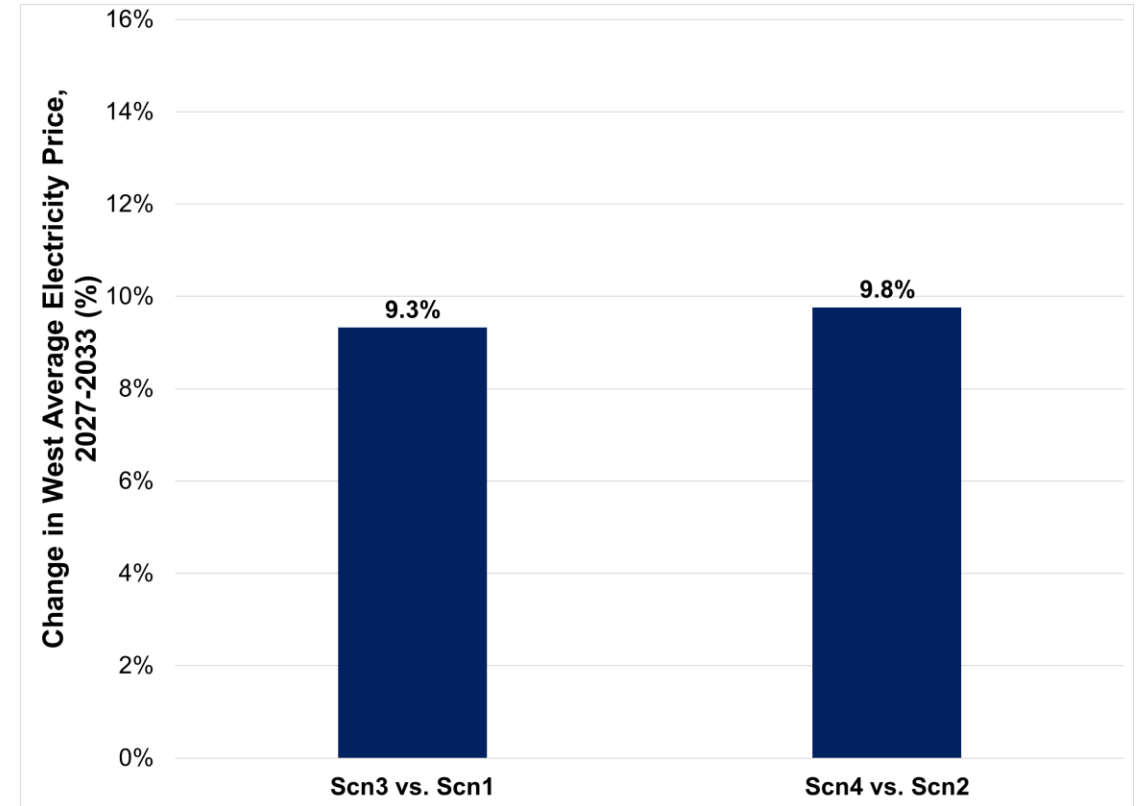
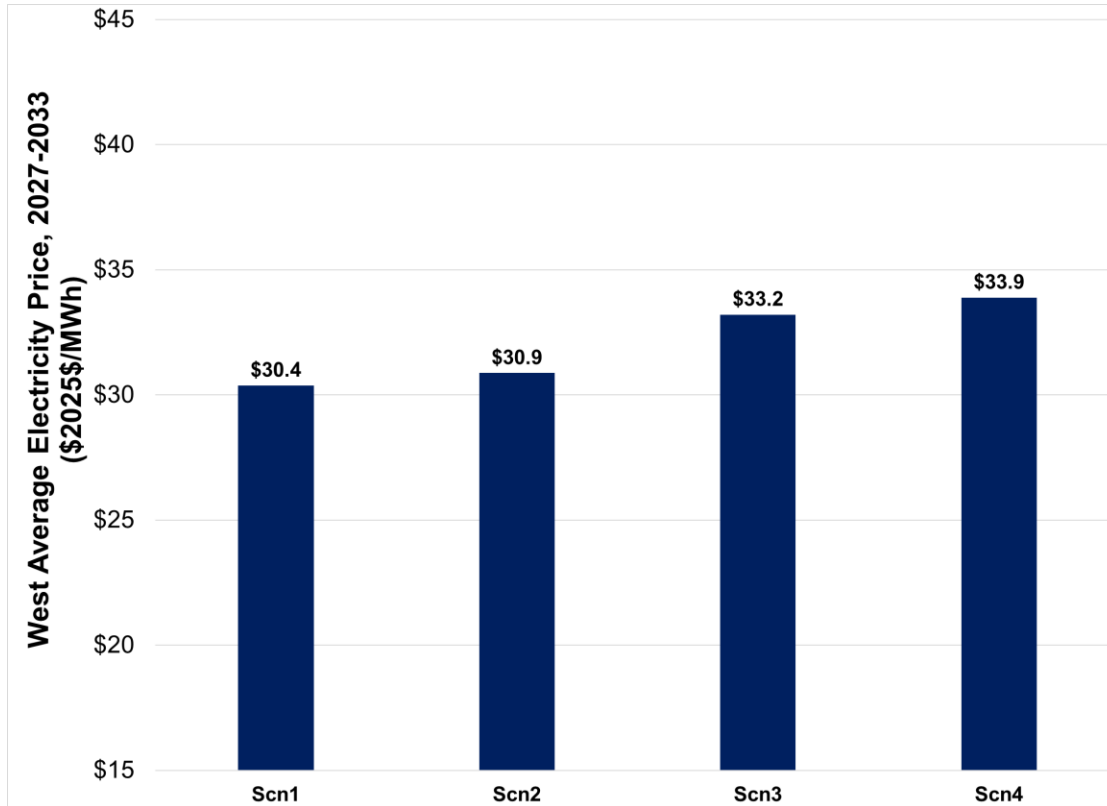


Note: Scn1 - Allow Wind/Solar; Scn2 - Allow Wind/Solar w/ High Demand, Scn3 - Constrain Wind/Solar; Scn4 - Constrain Wind/Solar w/ High Demand.

Note: Other" includes Oil CT, LFG, Battery Storage, Natural Gas CC w/ CCS, Biomass, Geothermal, Solar Thermal, Pumped Storage, MSW, Offshore Wind, and Coal w/ CC.

West Region: Key Results

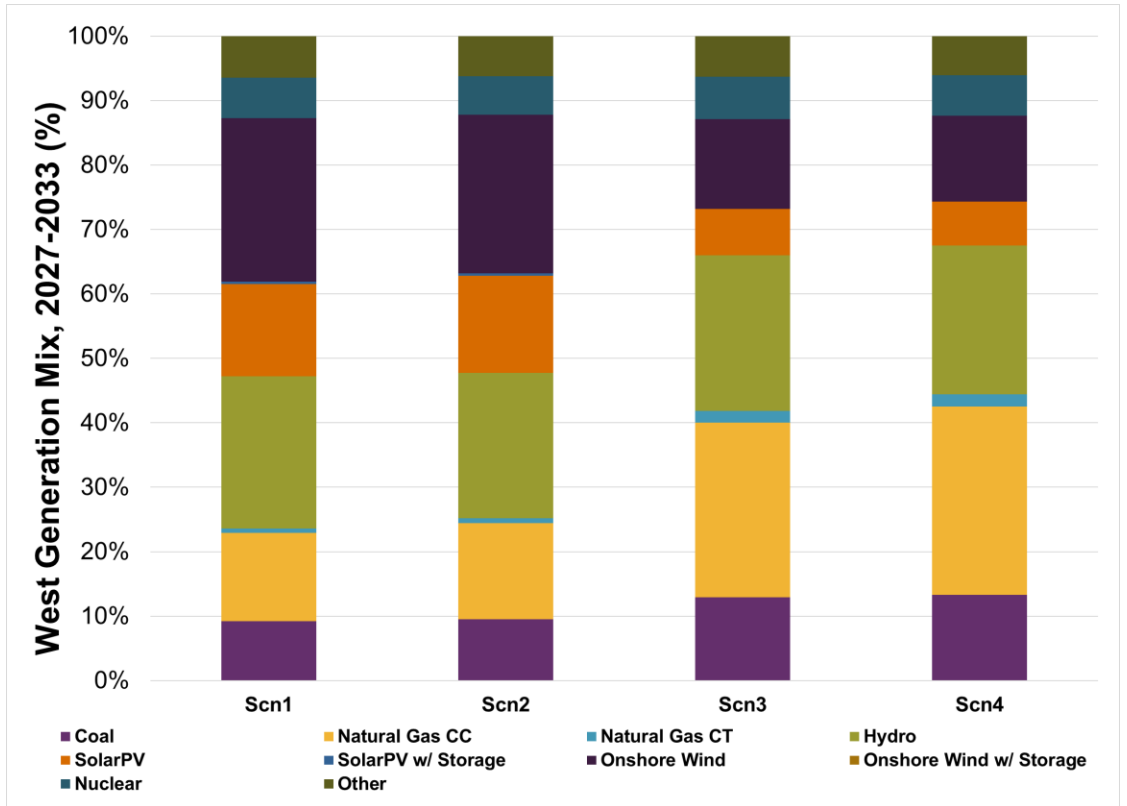
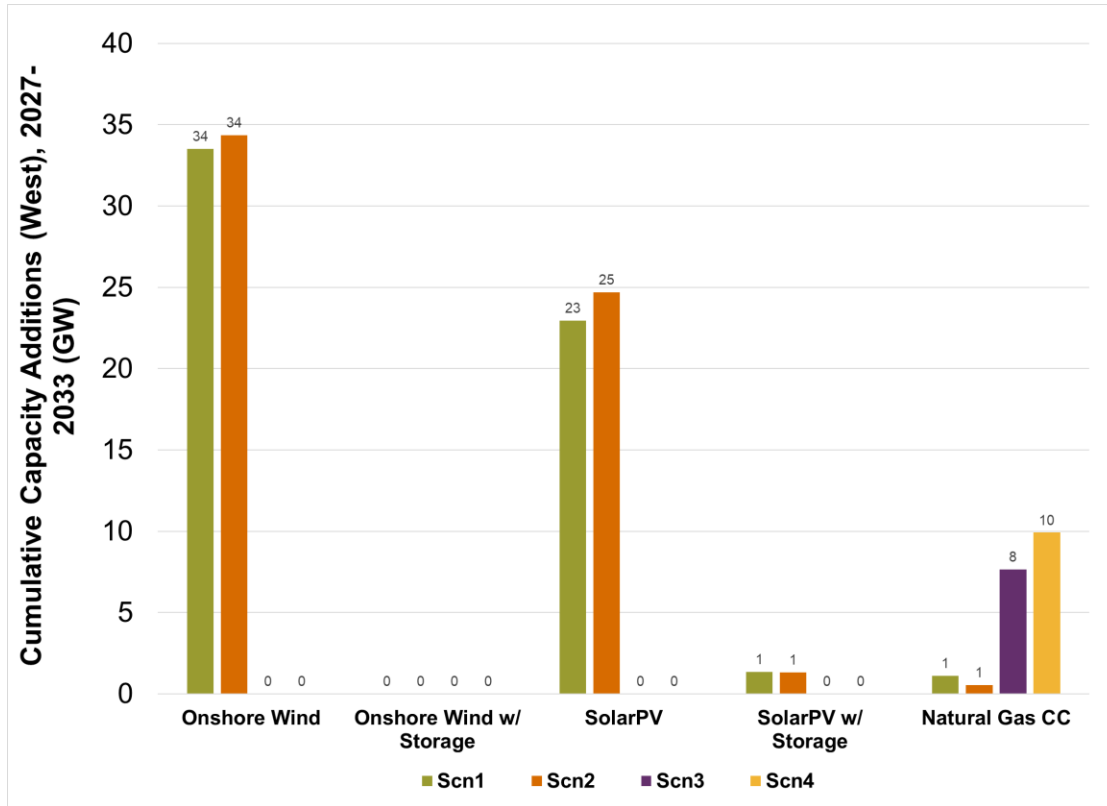
In the West, constraining solar and wind to compete on economics raises electricity prices by about 9-10%, driven by the absence of both solar and wind resources.



Note: Scn1 - Allow Wind/Solar; Scn2 - Allow Wind/Solar w/ High Demand; Scn3 - Constrain Wind/Solar; Scn4 - Constrain Wind/Solar w/ High Demand. The electricity prices reported are delivered residential electricity prices that is net of the T&D margin.
The Y-axis for the chart on the left begins from \$15/MWh for ease of visual depiction.

West Region: Key Results

In the West, constraining solar and wind to compete on economics leads to decreased deployment of both resources, along with a sharp increase in natural gas CC capacity additions.

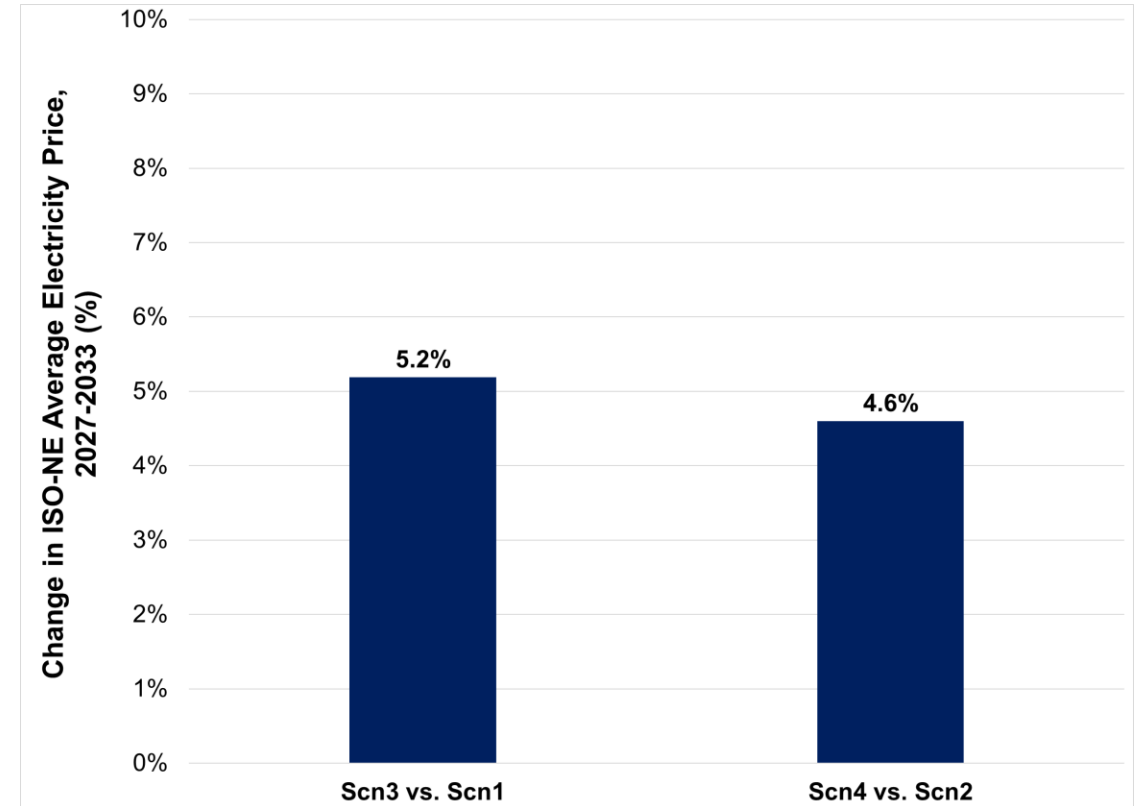
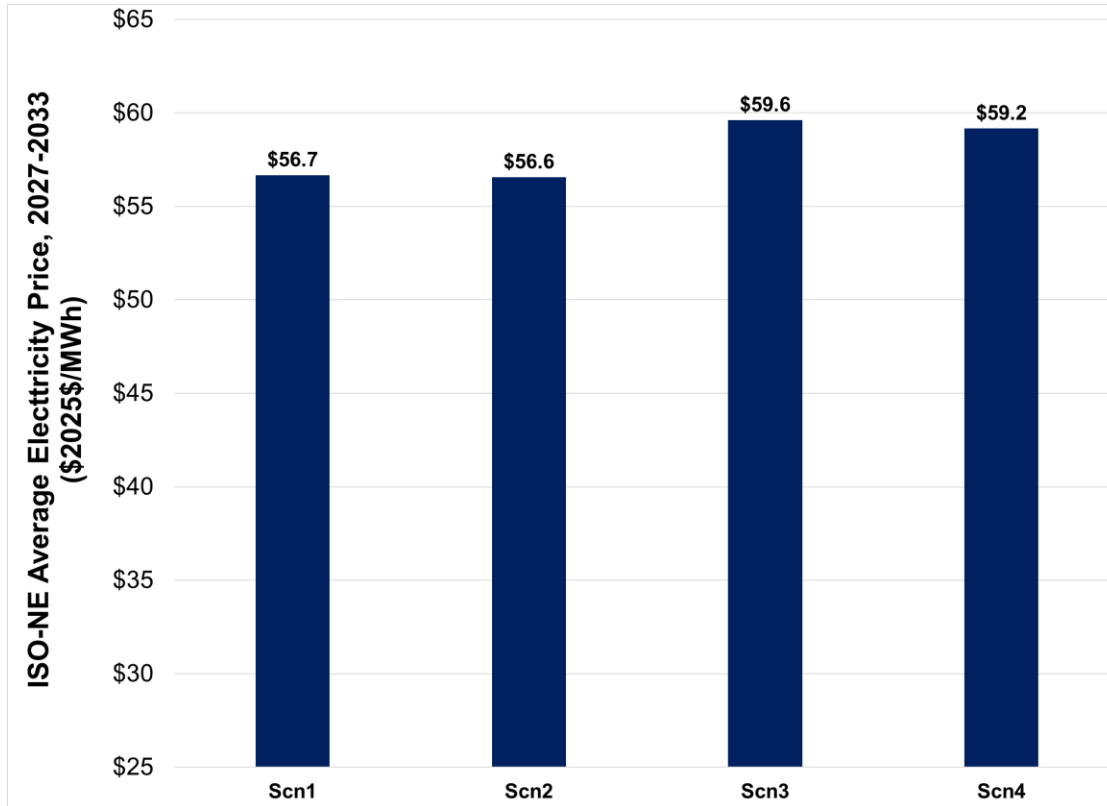


Note: Scn1 - Allow Wind/Solar; Scn2 - Allow Wind/Solar w/ High Demand, Scn3 - Constrain Wind/Solar; Scn4 - Constrain Wind/Solar w/ High Demand.

Note: Other" includes Oil CT, LFG, Battery Storage, Natural Gas CC w/ CCS, Biomass, Geothermal, Solar Thermal, Pumped Storage, MSW, Offshore Wind, and Coal w/ CC.

ISO-NE Region: Key Results

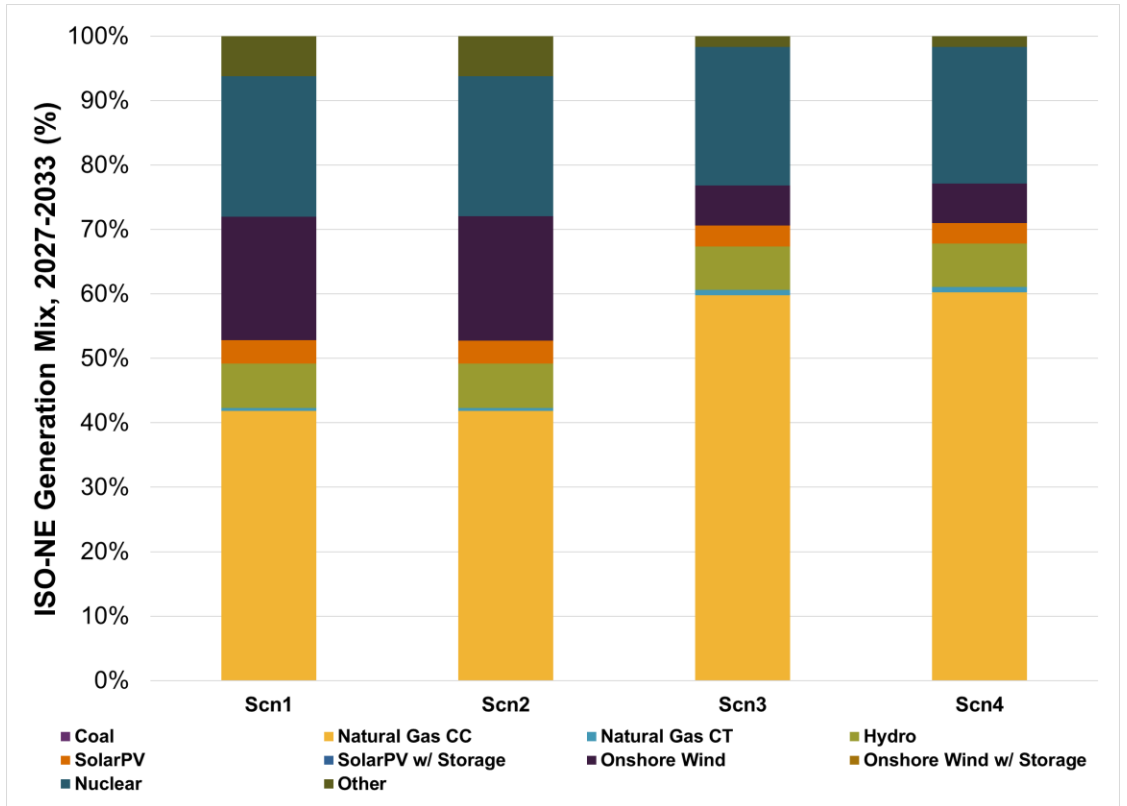
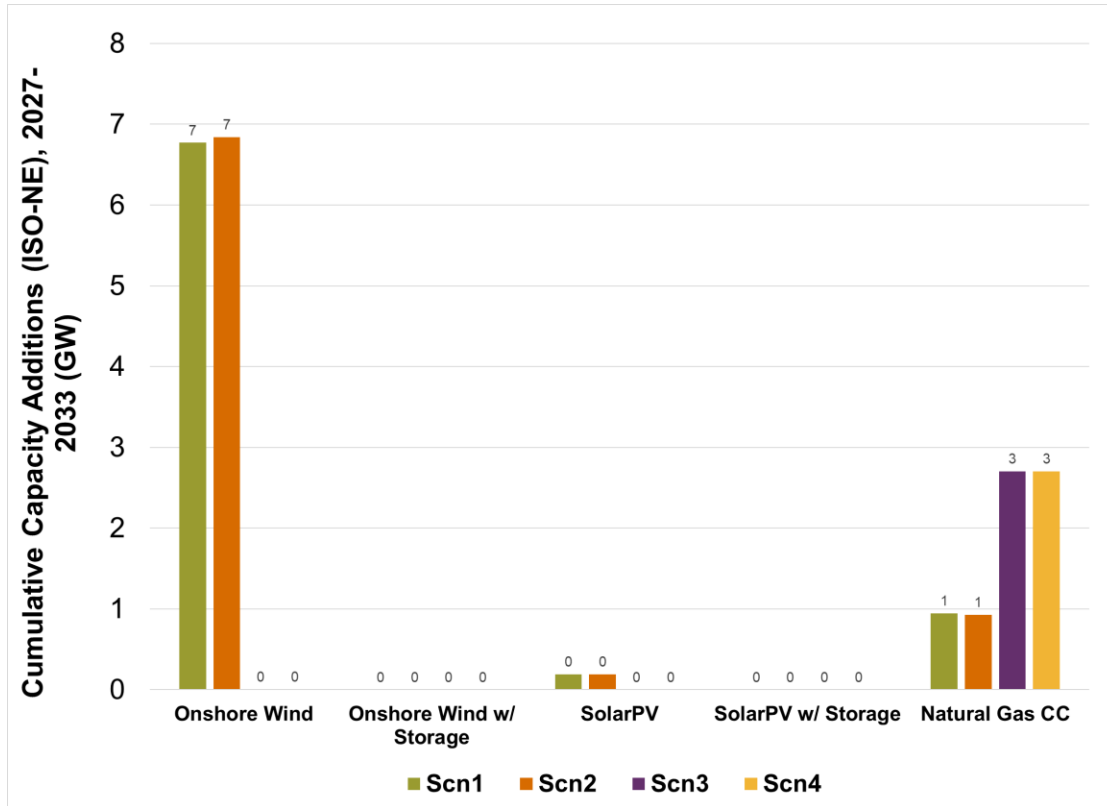
In ISO-NE, constraining solar and wind increases electricity prices by about 5% driven primarily by a decrease in wind resource deployment.



Note: Scn1 - Allow Wind/Solar; Scn2 - Allow Wind/Solar w/ High Demand; Scn3 - Constrain Wind/Solar; Scn4 - Constrain Wind/Solar w/ High Demand. The electricity prices reported are delivered residential electricity prices that is net of the T&D margin.
The Y-axis for the chart on the left begins from \$25/MWh for ease of visual depiction.

ISO-NE Region: Key Results

In ISO-NE, constraining solar and wind to compete on economics primarily decreases wind deployment. The decreased deployment of wind resources also lead to higher natural gas CC capacity additions.

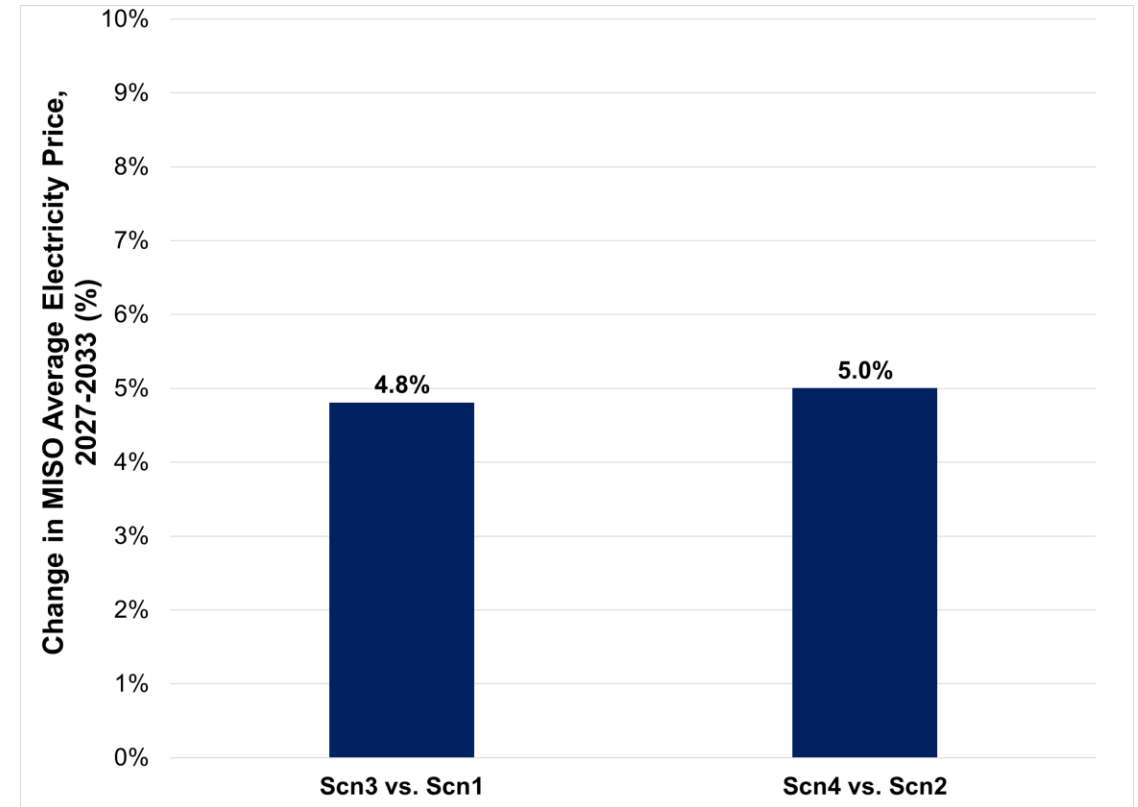
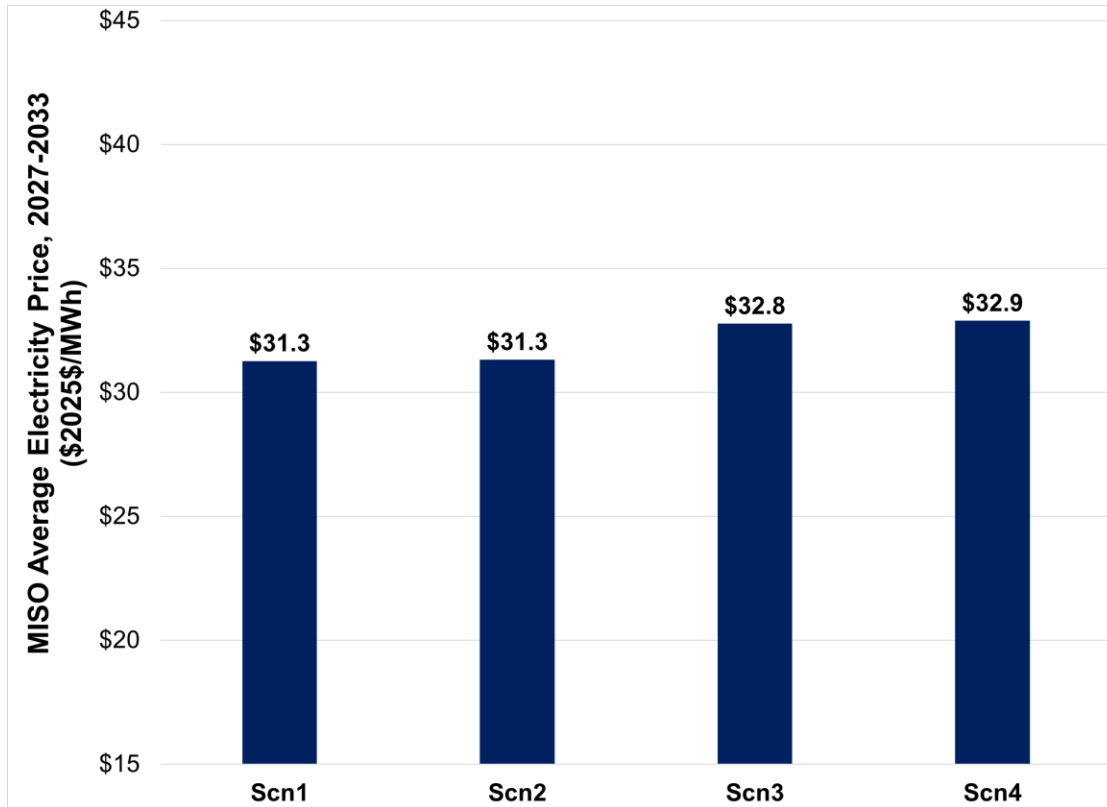


Note: Scn1 - Allow Wind/Solar; Scn2 - Allow Wind/Solar w/ High Demand, Scn3 - Constrain Wind/Solar; Scn4 - Constrain Wind/Solar w/ High Demand.

Note: Other" includes Oil CT, LFG, Battery Storage, Natural Gas CC w/ CCS, Biomass, Geothermal, Solar Thermal, Pumped Storage, MSW, Offshore Wind, and Coal w/ CC.

MISO Region: Key Results

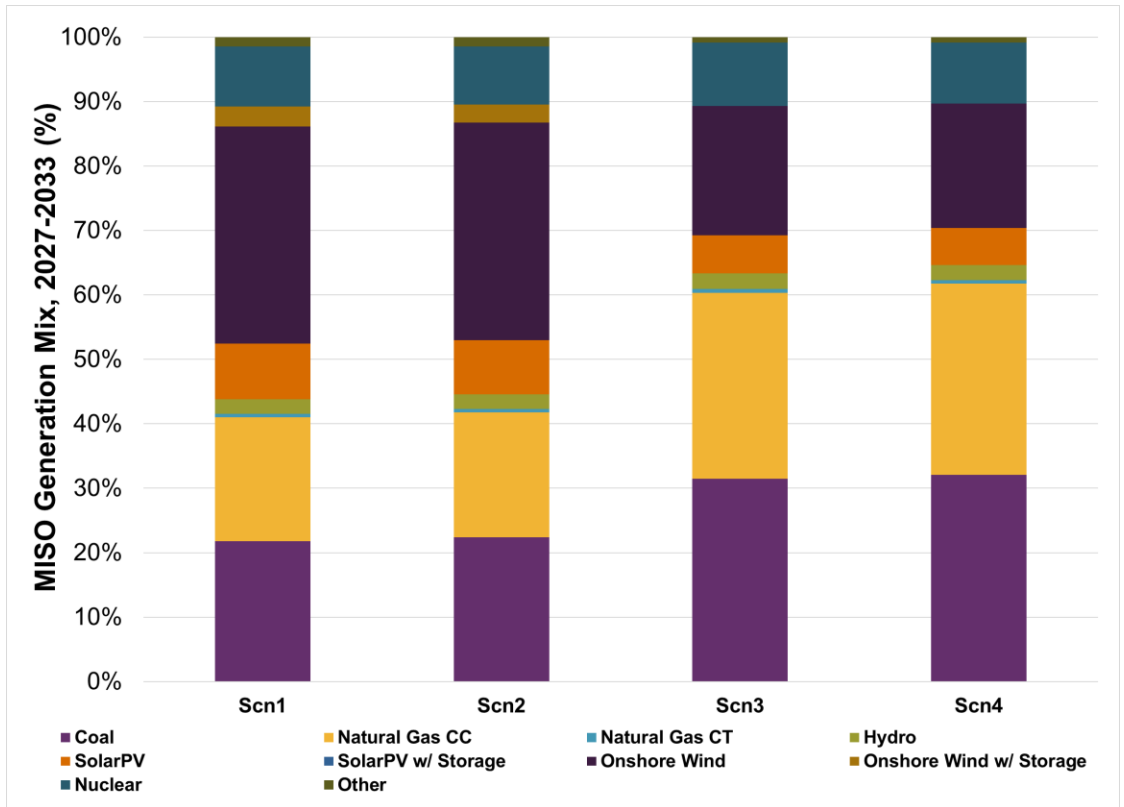
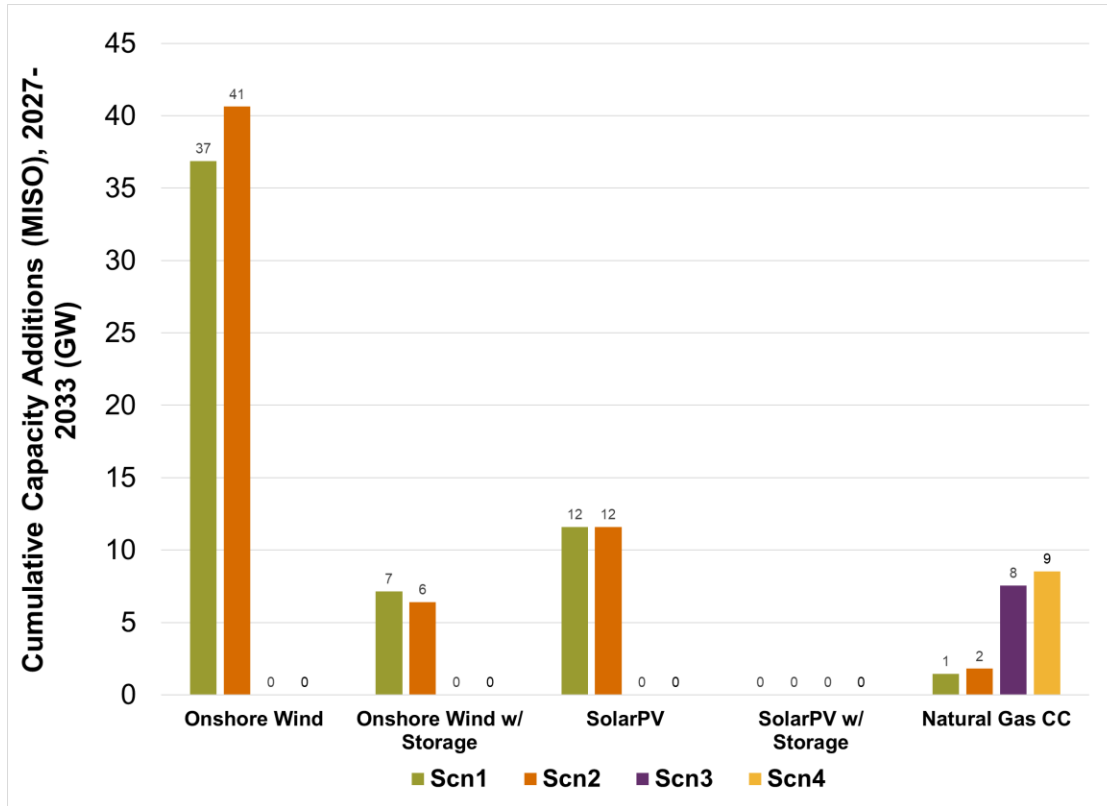
In MISO, constraining solar and wind increases electricity prices by about 5%, driven primarily by decrease in wind resource deployment.



Note: Scn1 - Allow Wind/Solar; Scn2 - Allow Wind/Solar w/ High Demand; Scn3 - Constrain Wind/Solar; Scn4 - Constrain Wind/Solar w/ High Demand. The electricity prices reported are delivered residential electricity prices that is net of the T&D margin.
The Y-axis for the chart on the left begins from \$15/MWh for ease of visual depiction.

MISO Region: Key Results

In MISO, constraining economic deployment of solar and wind results in a substantial change in wind deployment, complemented by modest wind with storage and solar additions driven by resource economics. As solar and wind deployment increases, natural gas CC capacity additions decline to nearly zero.

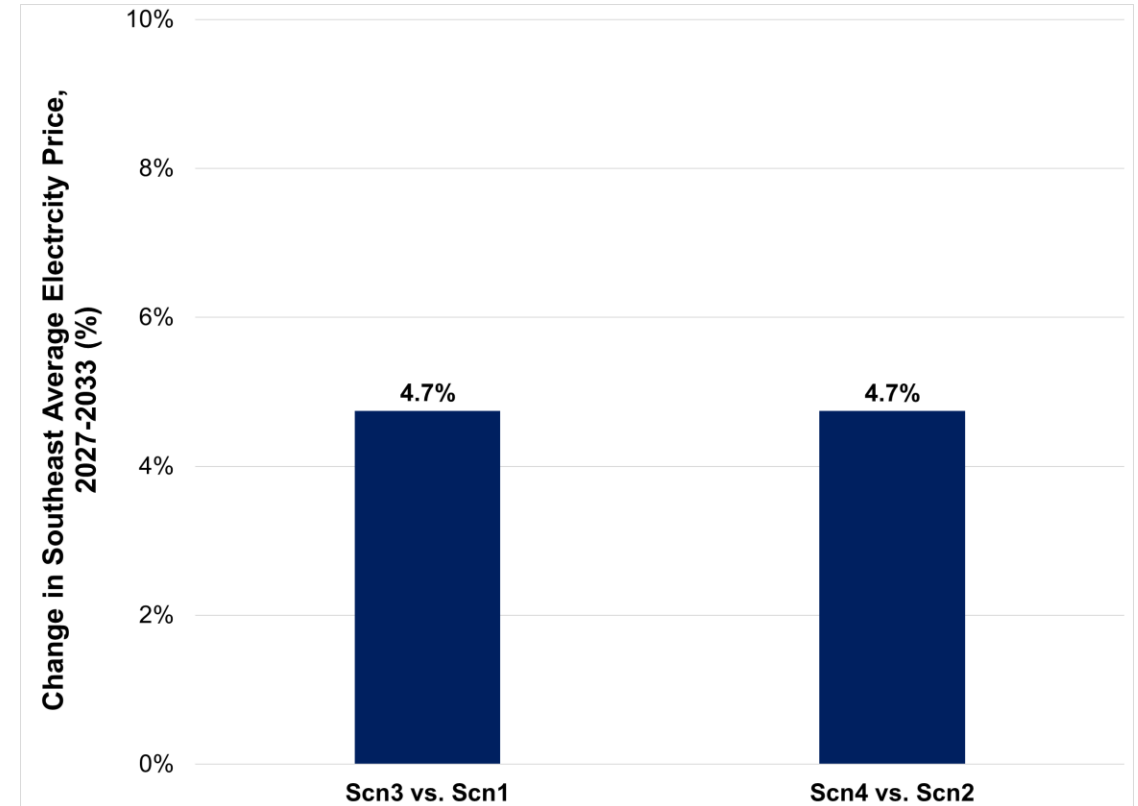
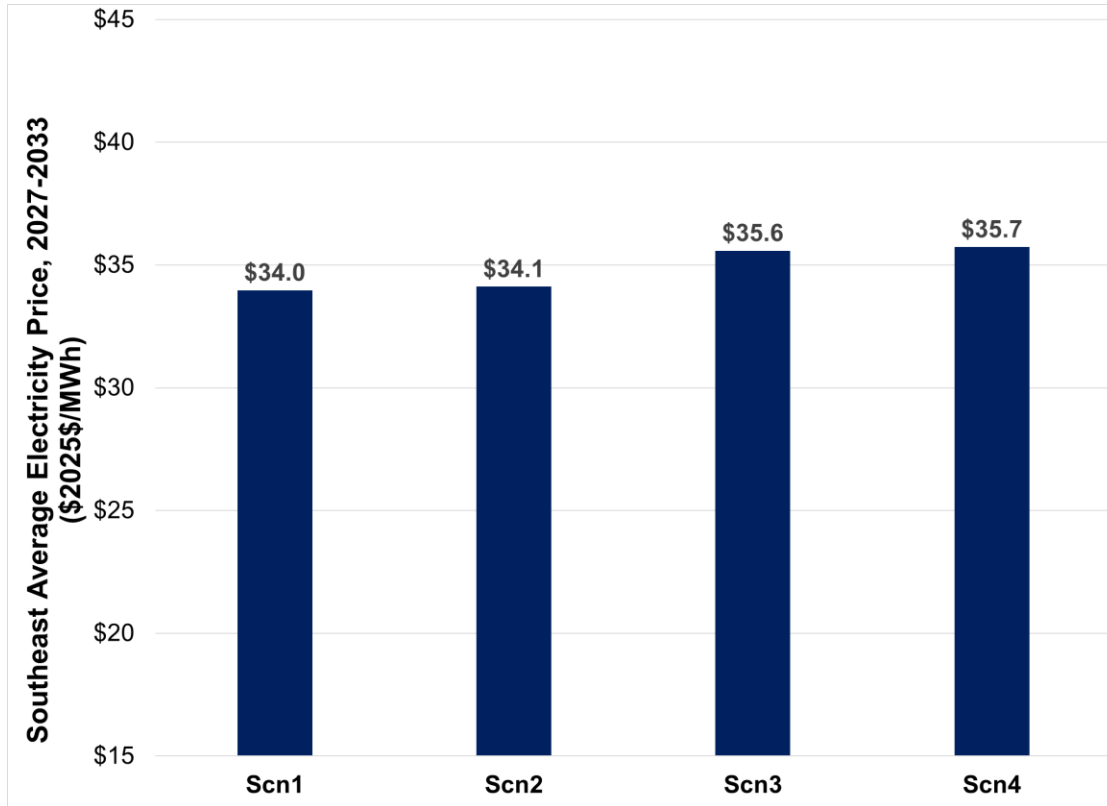


Note: Scn1 - Allow Wind/Solar; Scn2 - Allow Wind/Solar w/ High Demand, Scn3 - Constrain Wind/Solar; Scn4 - Constrain Wind/Solar w/ High Demand.

Note: "Other" includes Oil CT, LFG, Battery Storage, Natural Gas CC w/ CCS, Biomass, Geothermal, Solar Thermal, Pumped Storage, MSW, Offshore Wind, and Coal w/ CC.

Southeast Region: Key Results

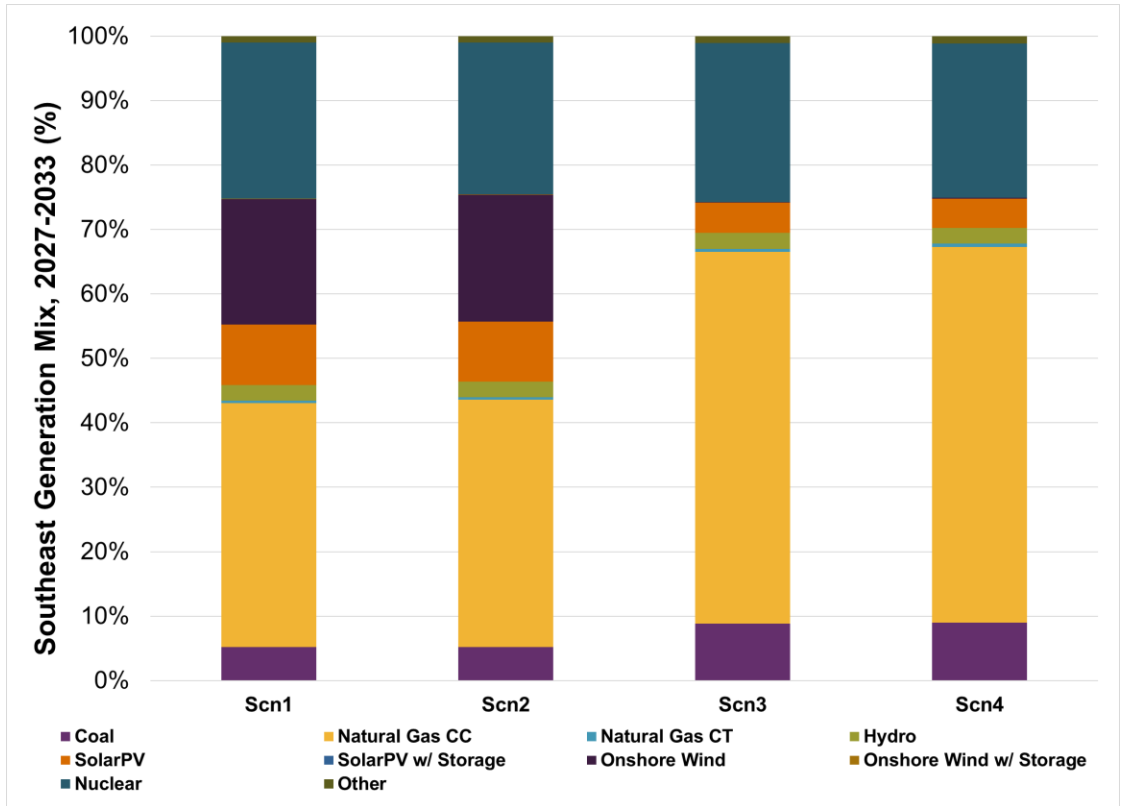
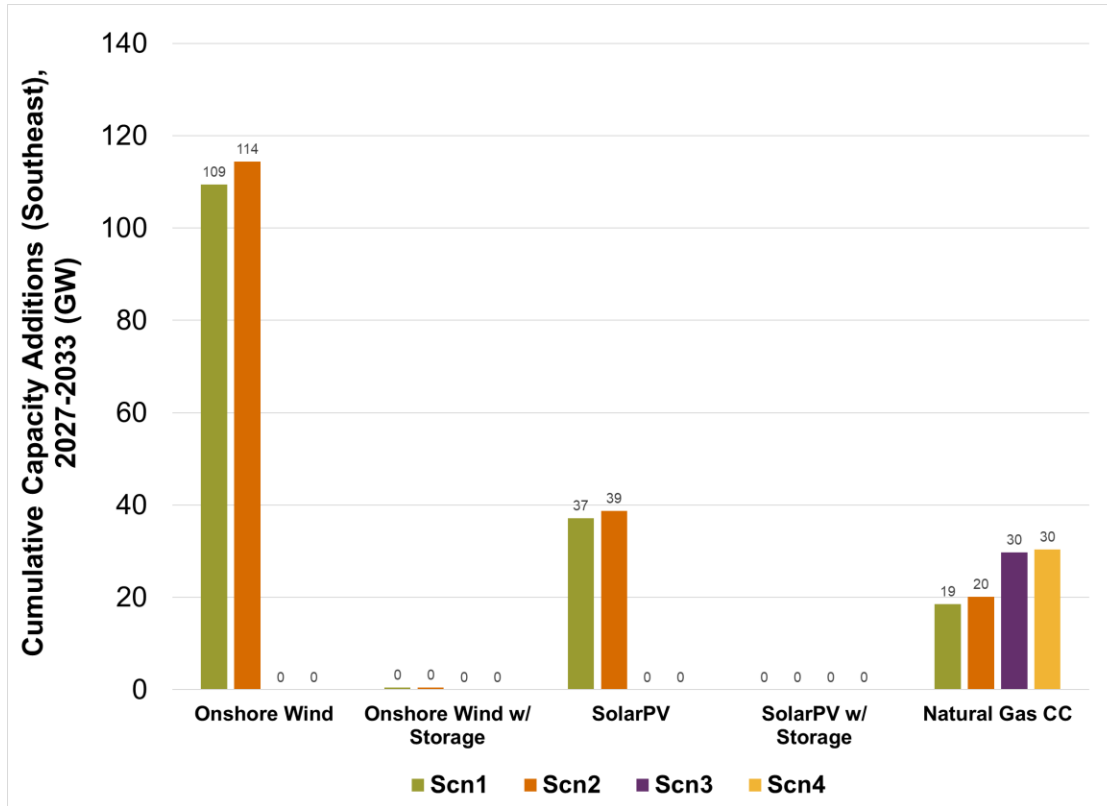
In the Southeast, constraining solar and wind increases electricity prices by about 5% driven primarily by a decrease in wind resource deployment.



Note: Scn1 - Allow Wind/Solar; Scn2 - Allow Wind/Solar w/ High Demand; Scn3 - Constrain Wind/Solar; Scn4 - Constrain Wind/Solar w/ High Demand. The electricity prices reported are delivered residential electricity prices that is net of the T&D margin. The Y-axis for the chart on the left begins from \$15/MWh for ease of visual depiction.

Southeast Region: Key Results

In the Southeast, lower electricity prices under the scenarios with economic solar and wind deployment (Scn1 and Scn2) are driven primarily by increased wind deployment, which exceeds solar builds by several times due to the region's strong wind resource potential. This wind build-out leads to modest reductions in natural gas CC capacity additions and a decline in natural gas CC generation share.

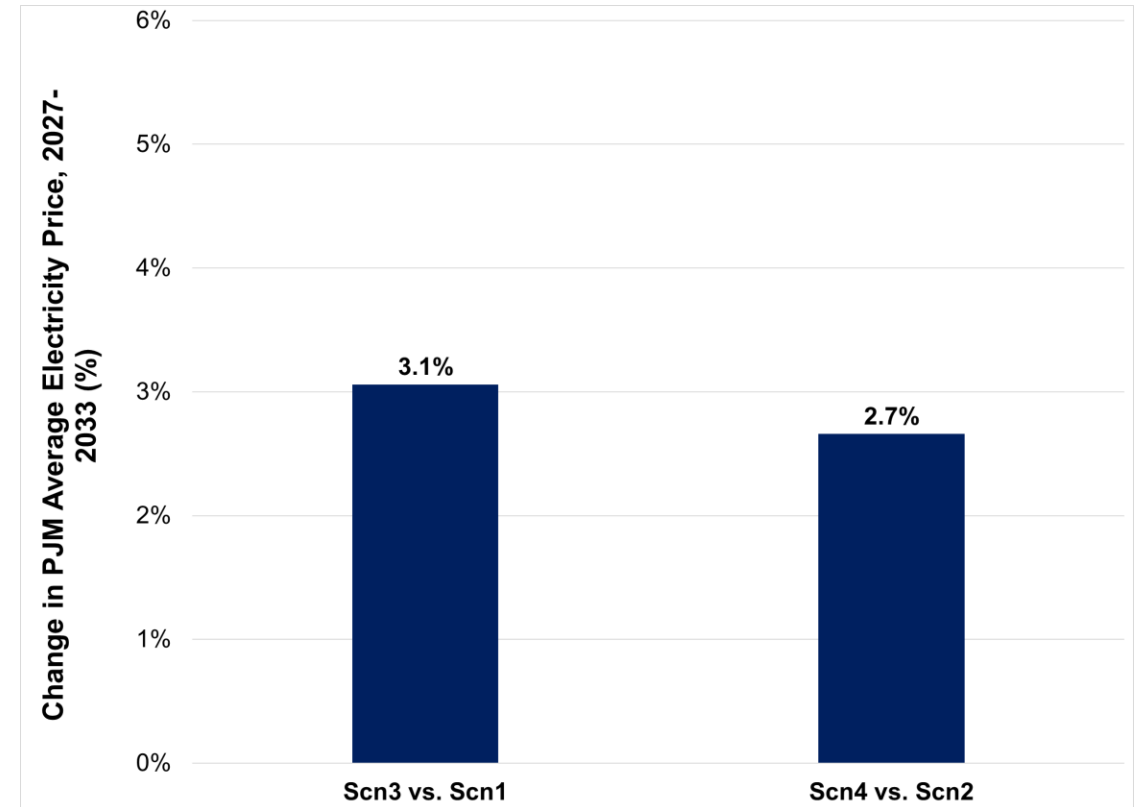
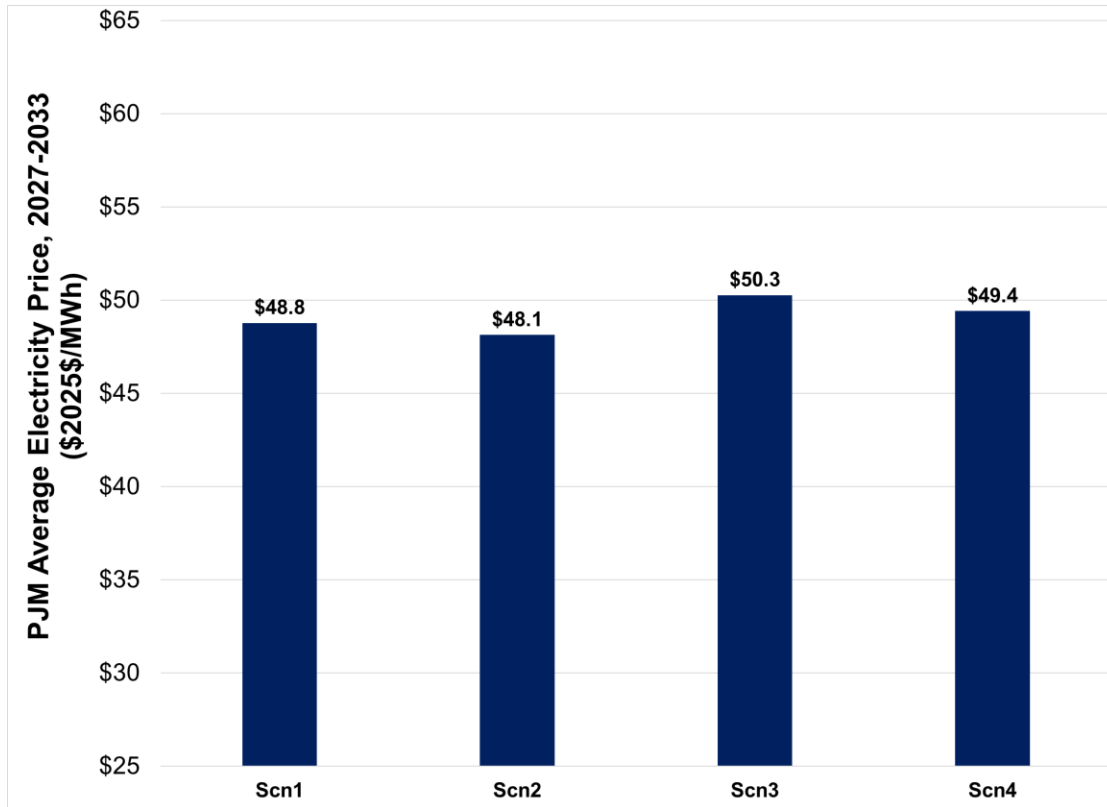


Note: Scn1 - Allow Wind/Solar; Scn2 - Allow Wind/Solar w/ High Demand, Scn3 - Constrain Wind/Solar; Scn4 - Constrain Wind/Solar w/ High Demand.

Note: Other" includes Oil CT, LFG, Battery Storage, Natural Gas CC w/ CCS, Biomass, Geothermal, Solar Thermal, Pumped Storage, MSW, Offshore Wind, and Coal w/ CC.

PJM Region: Key Results

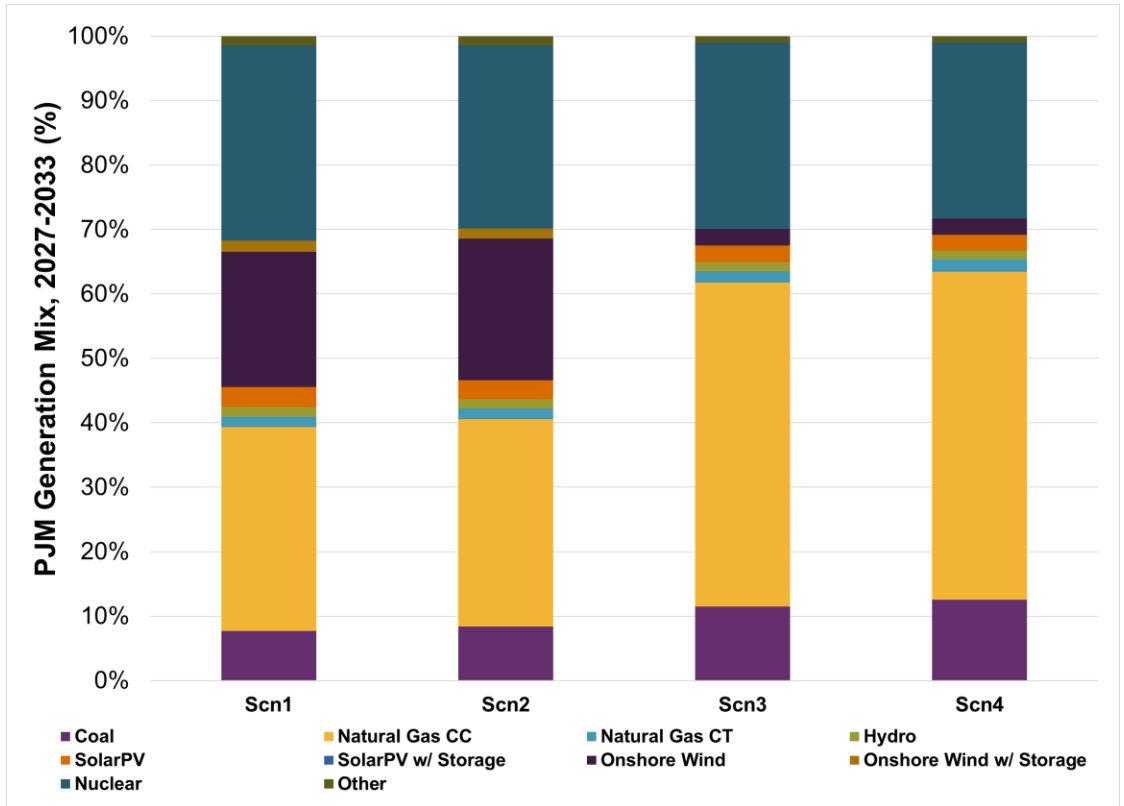
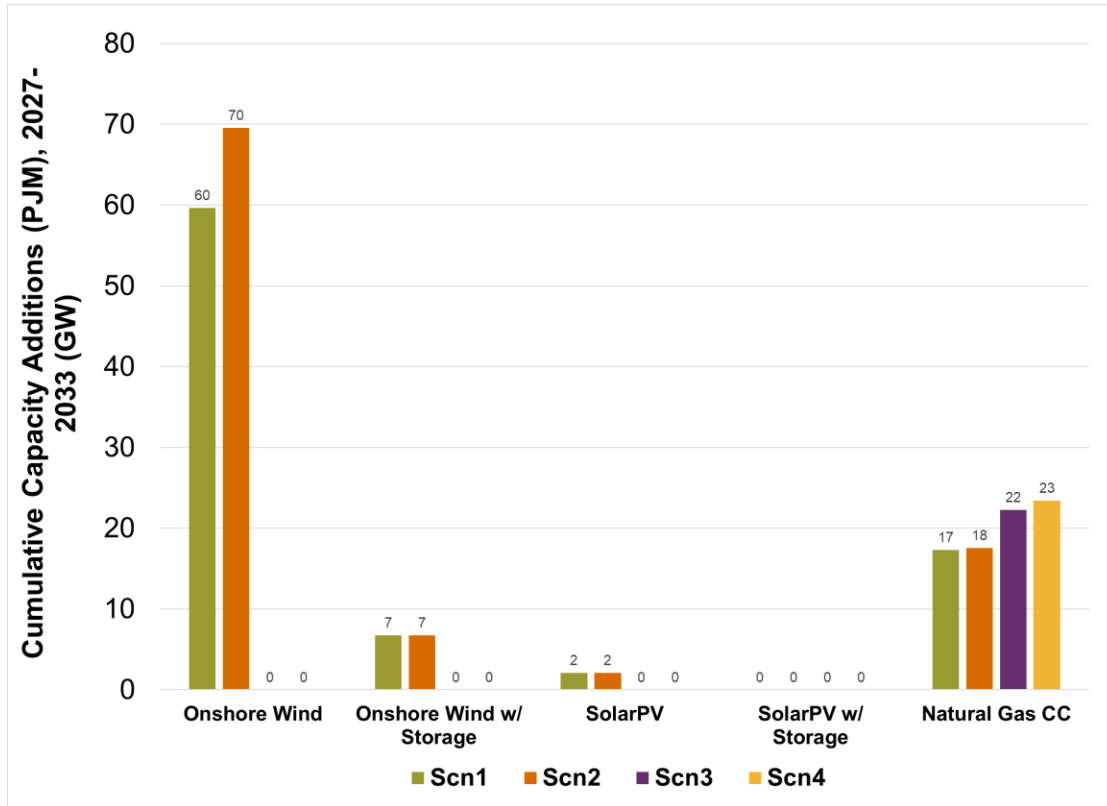
In PJM, constraining solar and wind to compete on economics increases electricity prices by about 3%, driven primarily by decrease in wind resource deployment.



Note: Scn1 - Allow Wind/Solar; Scn2 - Allow Wind/Solar w/ High Demand; Scn3 - Constrain Wind/Solar; Scn4 - Constrain Wind/Solar w/ High Demand. The electricity prices reported are delivered residential electricity prices that is net of the T&D margin.
The Y-axis for the chart on the left begins from \$25/MWh for ease of visual depiction.

PJM Region: Key Results

In PJM, allowing solar and wind to compete on economics increases wind deployment, and modestly reduces natural gas CC capacity additions.

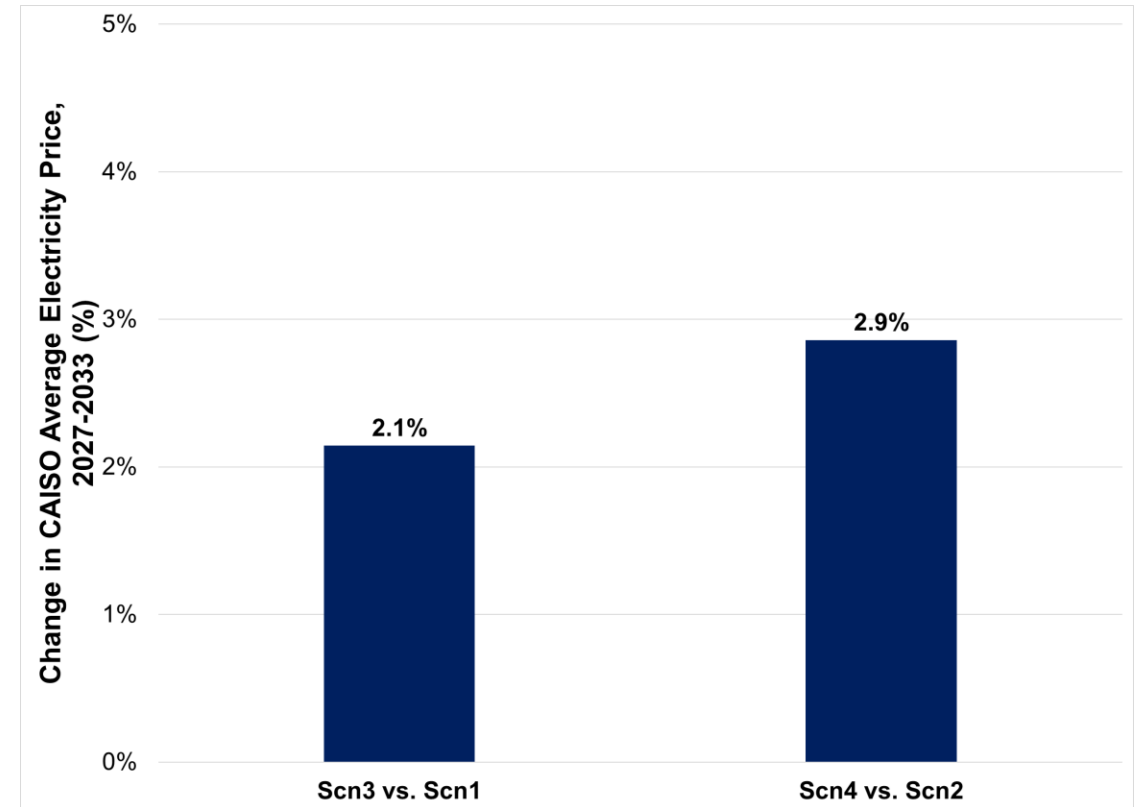
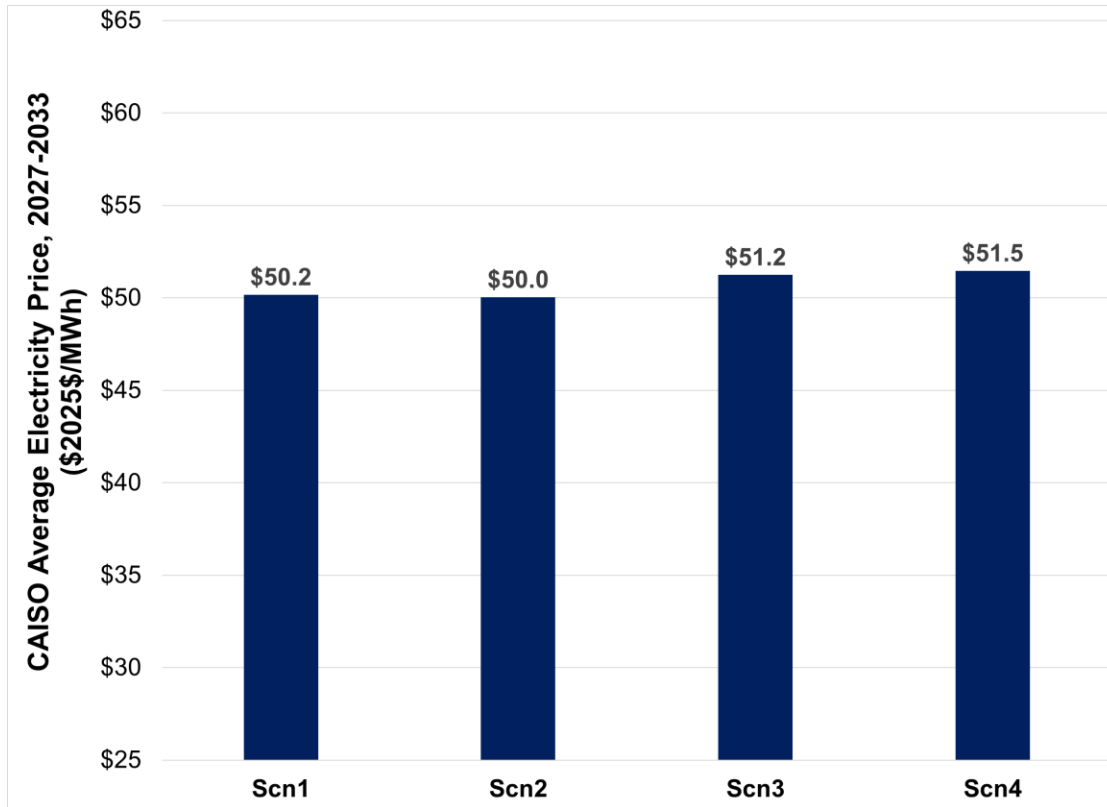


Note: Scn1 - Allow Wind/Solar; Scn2 - Allow Wind/Solar w/ High Demand, Scn3 - Constrain Wind/Solar; Scn4 - Constrain Wind/Solar w/ High Demand.

Note: Other" includes Oil CT, LFG, Battery Storage, Natural Gas CC w/ CCS, Biomass, Geothermal, Solar Thermal, Pumped Storage, MSW, Offshore Wind, and Coal w/ CC.

CAISO Region: Key Results

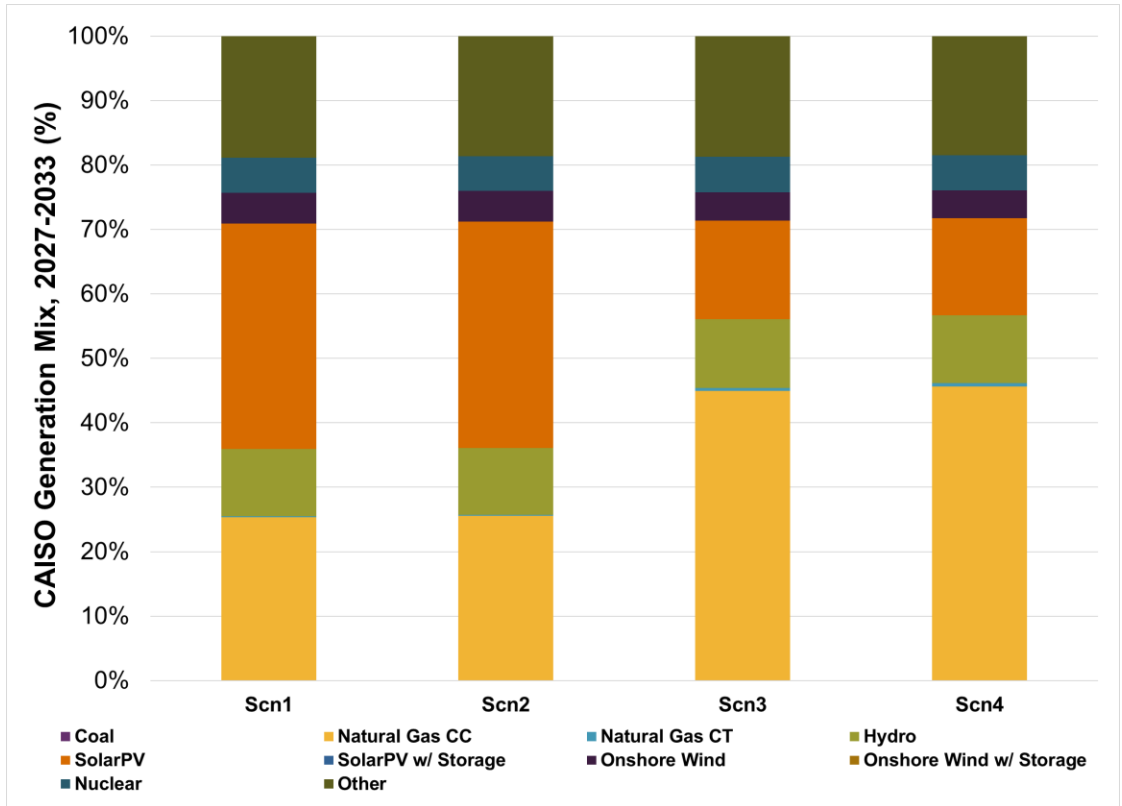
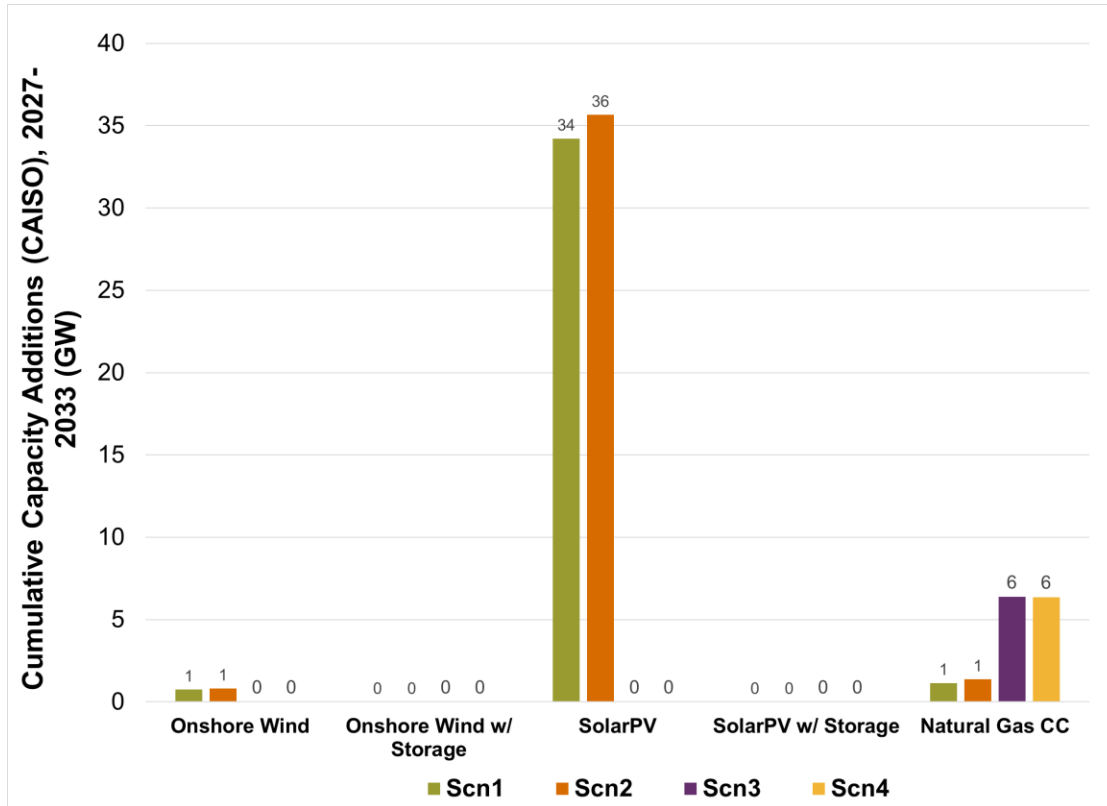
Electricity prices in CAISO are 2–3% higher when constraining solar and wind, driven primarily by decrease in solar deployment.



Note: Scn1 - Allow Wind/Solar; Scn2 - Allow Wind/Solar w/ High Demand; Scn3 - Constrain Wind/Solar; Scn4 - Constrain Wind/Solar w/ High Demand. The electricity prices reported are delivered residential electricity prices that is net of the T&D margin.
The Y-axis for the chart on the left begins from \$25/MWh for ease of visual depiction.

CAISO Region: Key Results

Allowing solar and wind deployment in CAISO primarily results in higher solar capacity additions. This increased solar build-out leads to modest reductions in natural gas CC capacity additions, a higher share of solar generation, and a lower share of natural gas CC generation.

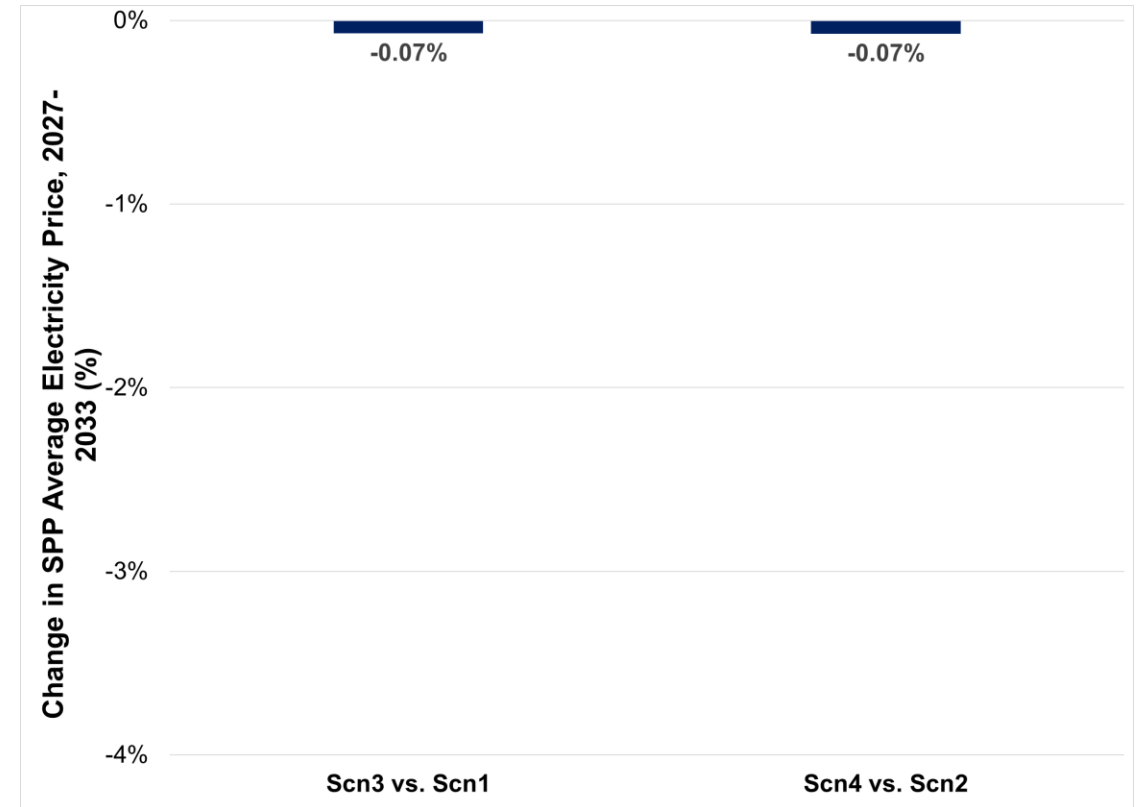
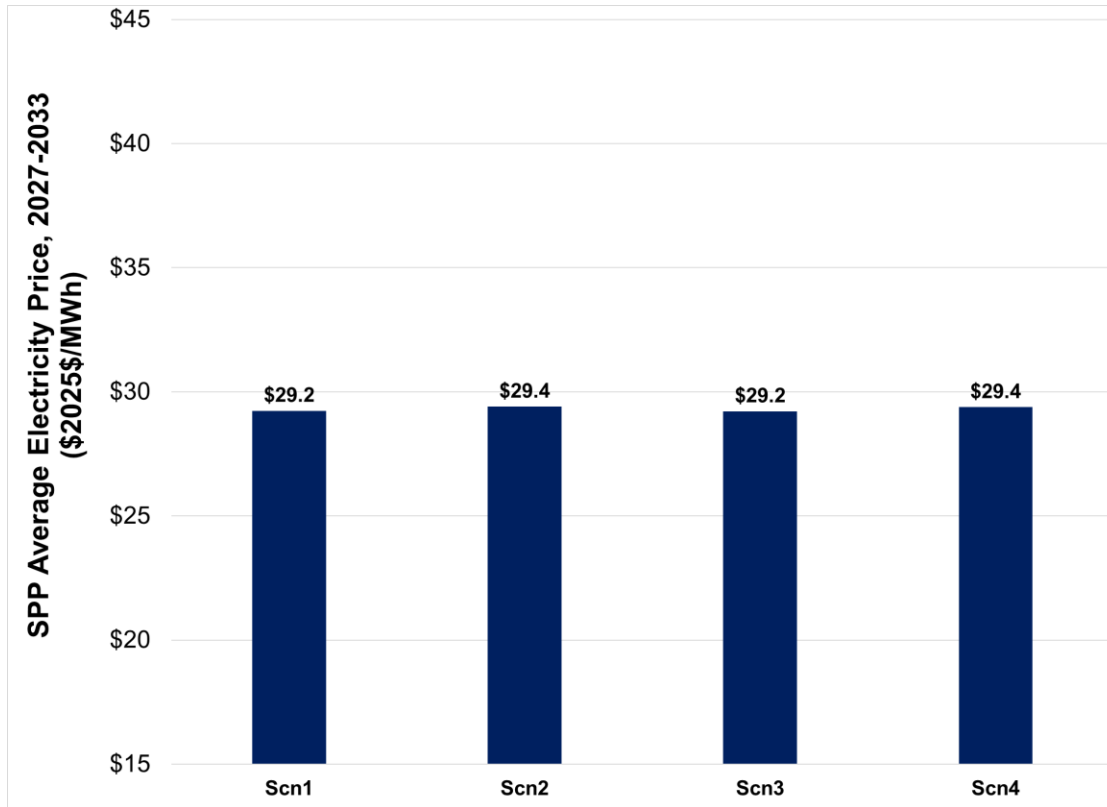


Note: Scn1 - Allow Wind/Solar; Scn2 - Allow Wind/Solar w/ High Demand, Scn3 - Constrain Wind/Solar; Scn4 - Constrain Wind/Solar w/ High Demand.

Note: Other" includes Oil CT, LFG, Battery Storage, Natural Gas CC w/ CCS, Biomass, Geothermal, Solar Thermal, Pumped Storage, MSW, Offshore Wind, and Coal w/ CC.

SPP Region: Key Results

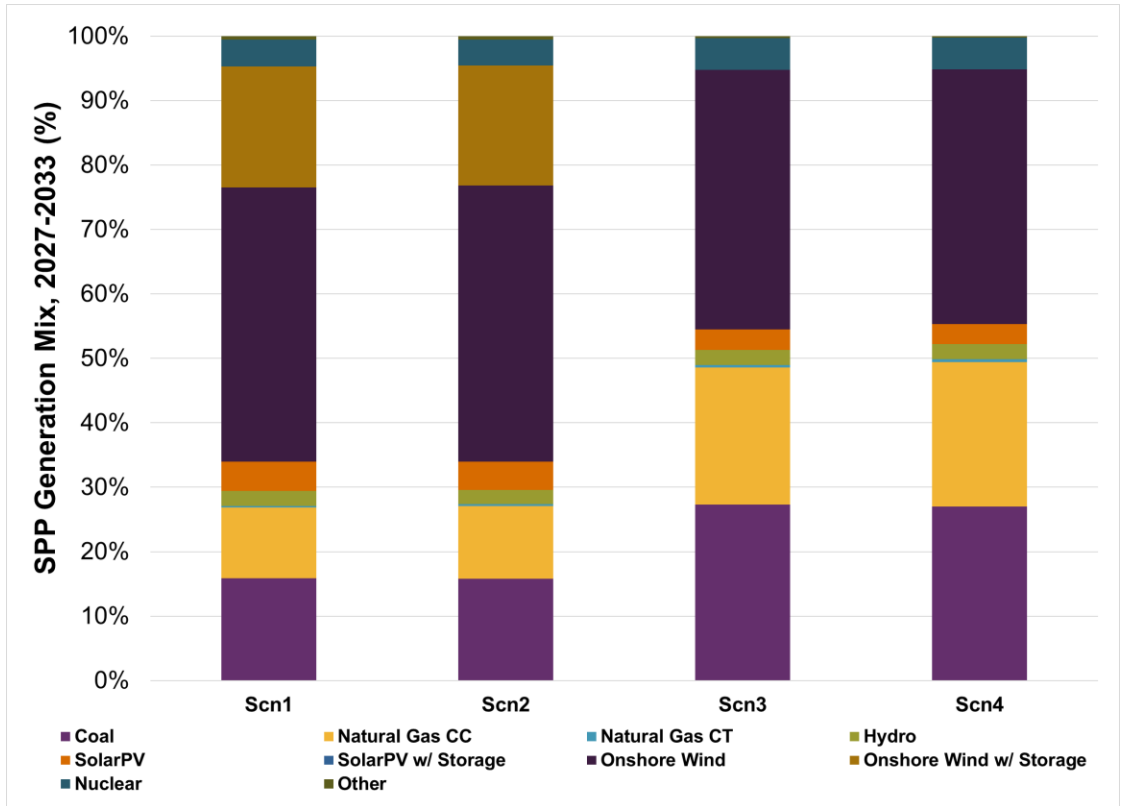
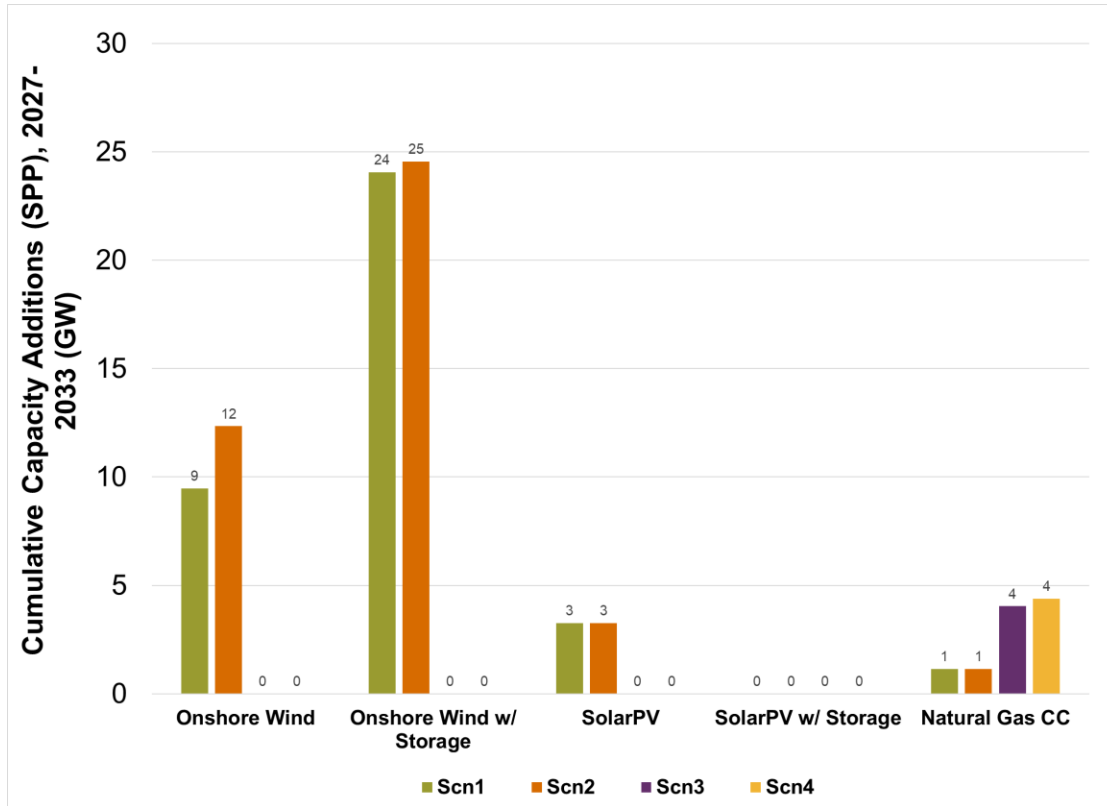
In SPP, constraining solar and wind to compete on economics has negligible impact on electricity prices. As a primarily cost-of-service region, constraining solar and wind deployment results in decrease in new build capital costs that is offset proportionally by an increase in natural gas CC new build capacity costs, fuel costs and electricity import costs.



Note: Scn1 - Allow Wind/Solar; Scn2 - Allow Wind/Solar w/ High Demand; Scn3 - Constrain Wind/Solar; Scn4 - Constrain Wind/Solar w/ High Demand. The electricity prices reported for this study are delivered residential electricity prices that is net of the T&D margin.
The Y-axis for the chart on the left begins from \$15/MWh for ease of visual depiction.

SPP Region: Key Results

In SPP, allowing solar and wind to compete on economics drives wind and wind with storage deployment, reflecting the region's strong wind resource potential, along with a modest reduction in natural gas CC capacity additions. Placing constraints on solar and wind deployment is seen to increase both coal and natural gas CC generation shares.



Note: Scn1 - Allow Wind/Solar; Scn2 - Allow Wind/Solar w/ High Demand, Scn3 - Constrain Wind/Solar; Scn4 - Constrain Wind/Solar w/ High Demand.

Note: Other" includes Oil CT, LFG, Battery Storage, Natural Gas CC w/ CCS, Biomass, Geothermal, Solar Thermal, Pumped Storage, MSW, Offshore Wind, and Coal w/ CC.

4 | Overview of the Modeling Approach

NERA's Electricity Market Impact Assessment Approach

A detailed electricity dispatch model and a state-level rate model is used using the latest data.

- NERA employed its 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 2026 publication released on April 8, 2026.^[1]
- The incremental demand from deployment of data centers were based on an EPRI study from 2026^[2] net of the projected electricity demand from data centers from EIA's AEO 2026 publication.
- 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 ratepayer class (residential, commercial, industrial) based on electricity market type in the state (competitive vs. cost-of-service).

^[1] U.S. EIA, Annual Energy Outlook 2026, available at <https://www.eia.gov/outlooks/aeo/assumptions/>.

^[2] EPRI, Powering Intelligence 2026: Updated Scenarios of U.S. Data Center Electricity Use and Power Strategies, available at <https://powering-intelligence.epri.com/>.

N_{ew}ERA Electricity Sector Model

The N_{ew}ERA 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 2027 to 2051 in 3-year time steps, with the results reported for the 2027-2033 time period.
- The Appendix provides more detail on the N_{ew}ERA 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 N_{ew}ERA 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.
- The Appendix provides more detail on the NERA rate model.

Electricity Prices Reported for this Study Represent Delivered Residential Electricity Prices that is Net of the Transmission and Distribution (T&D) Margin

The delivered residential electricity prices (net of the T&D margin) are estimated considering each region's electricity market structure.

- In the U.S., either a competitive or a cost-of-service market structure applies to the different states.^[1]
- The delivered electricity price in a competitive market (net of the T&D margin) is based on the wholesale energy, capacity and renewable energy credit (REC) costs.
 - 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 and CES requirements of the state(s) that are in the electricity market region.^[2]
- The delivered electricity price in a cost-of-service market (net of the T&D margin) is based on the cost of service (operating and investment costs of the generating resources in the market region). 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 and CES requirements of the state(s) that are in the electricity market region.^[2]

^[1] See Appendix for details on the NERA rate model and applicable market structure by state.

^[2] RPS and CES policies are not modeled in the scenarios analyzed in this study and thus no credit costs are accounted for in the electricity prices in the modeled scenarios.

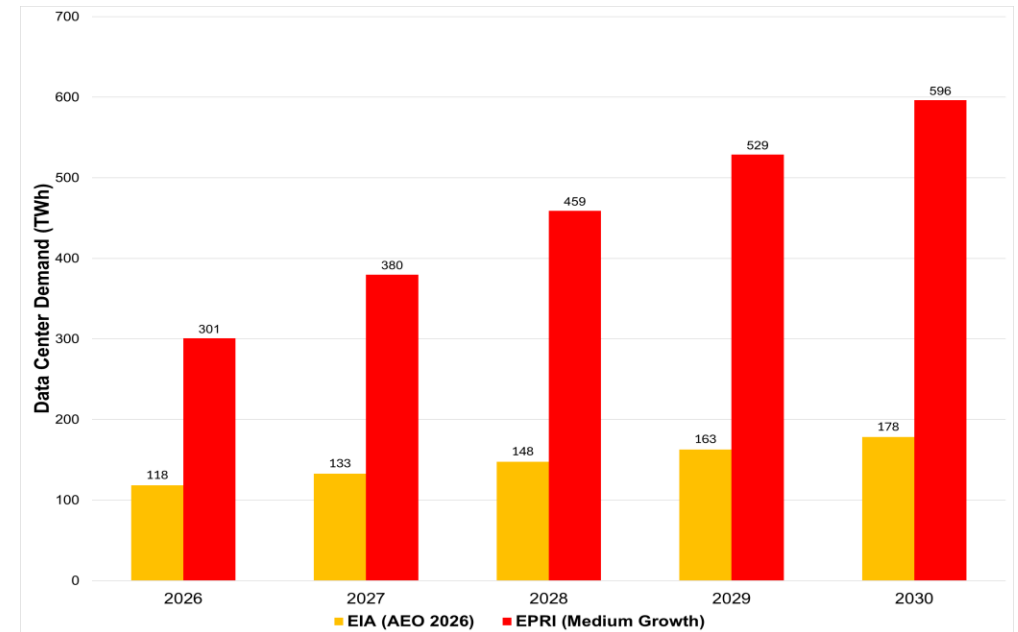
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Overview of the Key Modeling Assumptions

Key Modeling Assumptions: Electricity Demand

The incremental electricity demand from data center growth assumed for this study equals 184 TWh in 2026 increasing to 419 TWh in 2030.

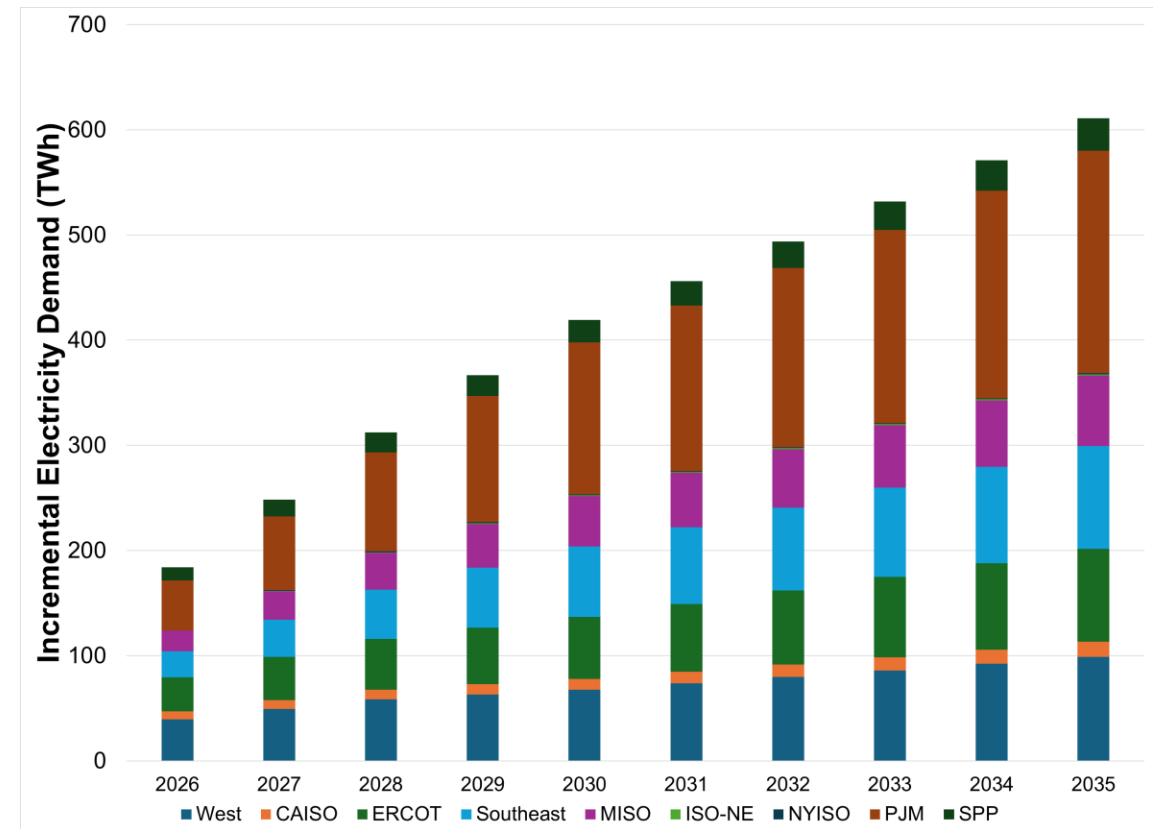
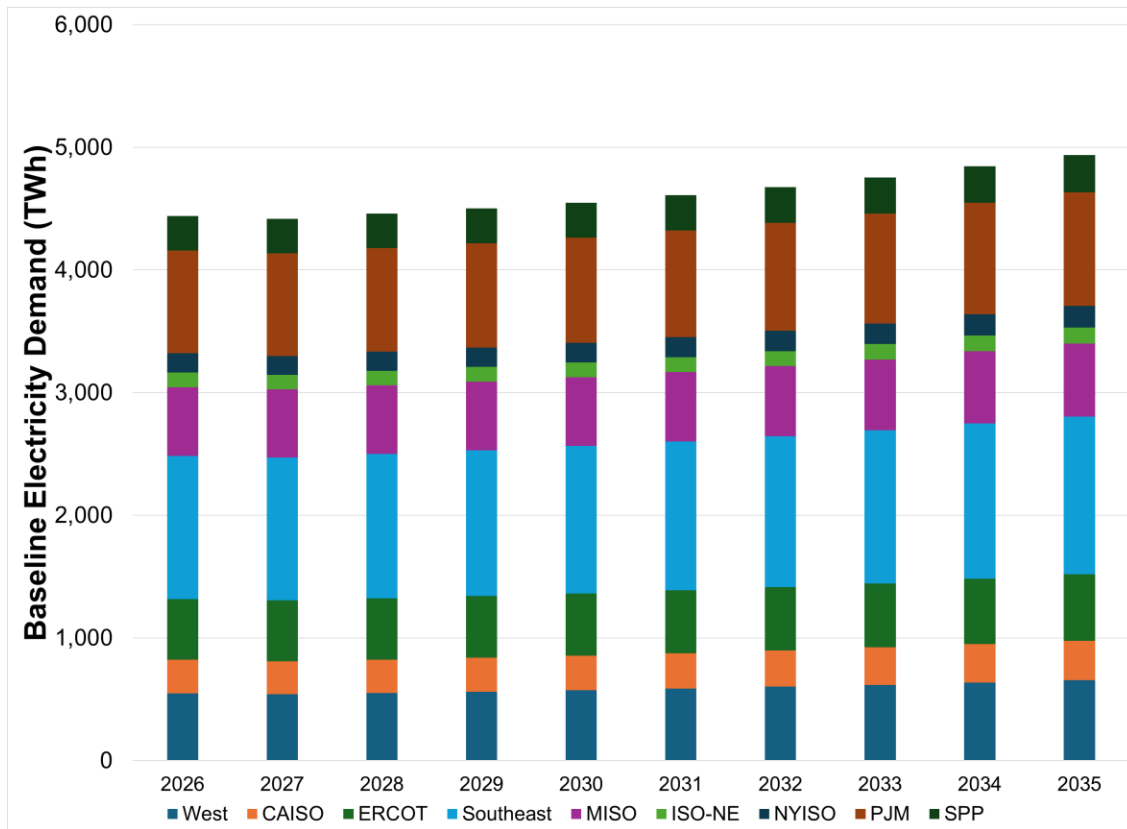
- NERA's assumption for the incremental demand from data center growth for this study are based on the Medium Growth scenario in the 2026 EPRI study ^[1] net of the electricity demand from data centers from the EIA's AEO 2026 projections.
 - The Medium Growth scenario assumes that all projects under construction, 75% of those in advanced planning, and 10% in early planning are fully operational by 2030.
 - Under this scenario, the incremental electricity demand from data centers are projected to increase from 301 TWh in 2026 to 596 TWh by 2030.
 - The EIA's AEO 2026 projects incremental electricity demand from data centers to increase from 118 TWh in 2026 to 178 TWh by 2030.
- The incremental electricity demand from data centers is assumed to be equal to 184 TWh in 2026 increasing to 419 TWh by 2030. Beyond 2030, the incremental electricity demand was assumed to increase at the growth rate underlying EIA's AEO 2026 data center demand projections.
- 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.



^[1] EPRI, Powering Intelligence 2026: Updated Scenarios of U.S. Data Center Electricity Use and Power Strategies, available at <https://powering-intelligence.epri.com/>.

Key Modeling Assumptions: Electricity Demand

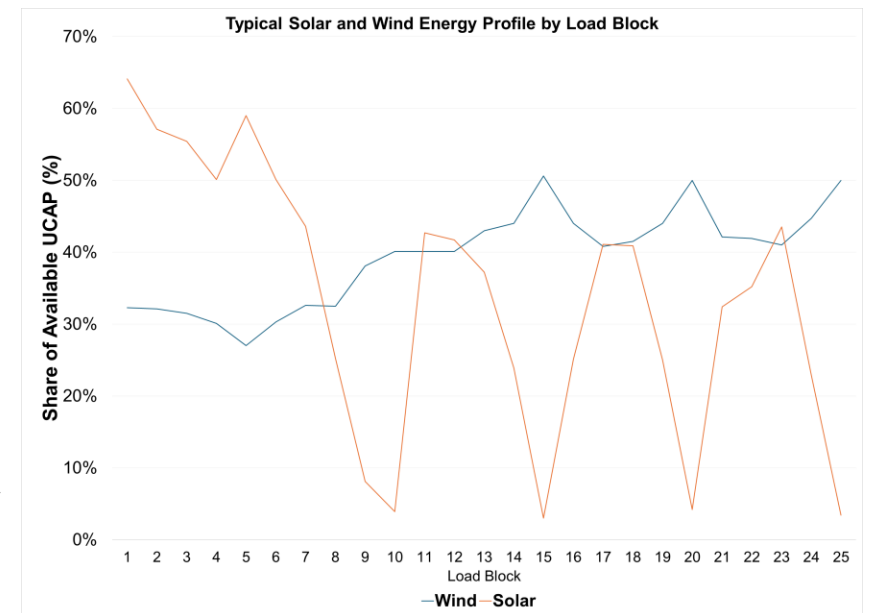
Across the regions, the largest incremental electricity demand from data centers is observed in the PJM region – 47 TWh in 2026 rising to 212 TWh by 2035. PJM accounts for a significant share of the total incremental demand from data center growth (26% in 2026 rising to 35% by 2035). The total electricity demand in PJM (inclusive of incremental data center demand) is 6% above baseline demand in 2026 increasing to 23% by 2035.



Key Modeling Assumptions: Intermittency Limits and Transmission

The N_{ew} ERA model addresses the challenges of overgeneration and curtailment from large-scale deployment of solar and wind.

- Two different modeling constraints in the N_{ew} ERA model are imposed to address large-scale deployment of intermittent resources in the model – intermittency limits and energy profiles.
- The total generation from intermittent resources is constrained to a maximum limit. These maximum limits are set for each model region and load block.
 - This limits the share of intermittent generation in total generation. The range of generation share from intermittent resources varies from 50% to 85% in the model depending upon the region.
- Each intermittent resource is associated with its own energy profile that limits its unforced capacity (UCAP) availability.
 - This limit represents the maximum capacity factor for intermittent resources in each load block with the energy profile is based on intermittent resource's maximum energy potential in each hour.
- Beyond this limit, the model chooses other types of resources (thermal resources such as natural gas and clean firm resources such as nuclear, hydro, geothermal etc.) to meet the demand in the load block in a least cost manner.
- The model also does not build new transmission to support additional solar and wind resources; instead, it selects a mix of resources (both existing and new) on a least cost basis that optimizes the use of existing transmission capacity to meet demand.



Key Modeling Assumptions: Federal Tax Incentives

The tax incentives modeled in the NERA Study are consistent with the U.S. EIA's assumptions that relate to applicability of the incentives to specific technologies under the Inflation Reduction Act (IRA) and the revised timeline for tax credit expiry under the One Big Beautiful Bill (OBBBA) Act.

- For this study, two types of tax incentives are incorporated: the §45Y production tax credit (PTC) and the §48E investment tax credit (ITC) based on U.S. EIA's assumptions. ^[1]
 - The PTC was applied to new onshore wind, onshore wind with storage, solar, and solar with storage and assumed to apply to projects that are placed in service no later than 2030 because of Treasury's 4-year "begin construction" safe harbor guidance.
 - 1.65 cents/kWh (1992\$) for new onshore wind, onshore wind with storage; 1.5 cents/kWh (1992\$) for new solar and solar with storage.
 - The PTC was also applied to new biomass and nuclear projects with the credits assumed to expire at the end of 2027.
 - 1.5 cents/kWh (1992\$) for new biomass and 1.65 cents/kWh (1992\$) for new nuclear.
 - The ITC was applied to new storage, hydropower, geothermal and offshore wind projects
 - For new storage, hydropower and geothermal projects, a 30% ITC was assumed to apply with a more gradual phase-out – 100% until 2033, 75% in 2034, 50% in 2035 and zero thereafter.
 - For new offshore wind projects, a 30% ITC was assumed to apply – 100% until 2028 and zero thereafter.
 - All technologies were assumed to be eligible for the base credit plus the bonus credits for prevailing wage and apprenticeship requirements.
 - Except for new nuclear and onshore wind, none of the other technologies assumed to be eligible for the bonus credits from meeting domestic content requirements.
 - None of the technologies were assumed to meet the bonus credits for location in energy communities.
- Additionally, the §45U zero-emission nuclear PTC (\$15/MWh in 1992\$) was applied to existing nuclear resources with the full value of the credit assumed to apply until 2032 and zero thereafter.

^[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

7

Appendix:
About the N_{ew}ERA Model

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 meet 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 and CES requirements of the state(s) that are in the electricity market region.

State-Level Delivered Electricity Rate Model (2)

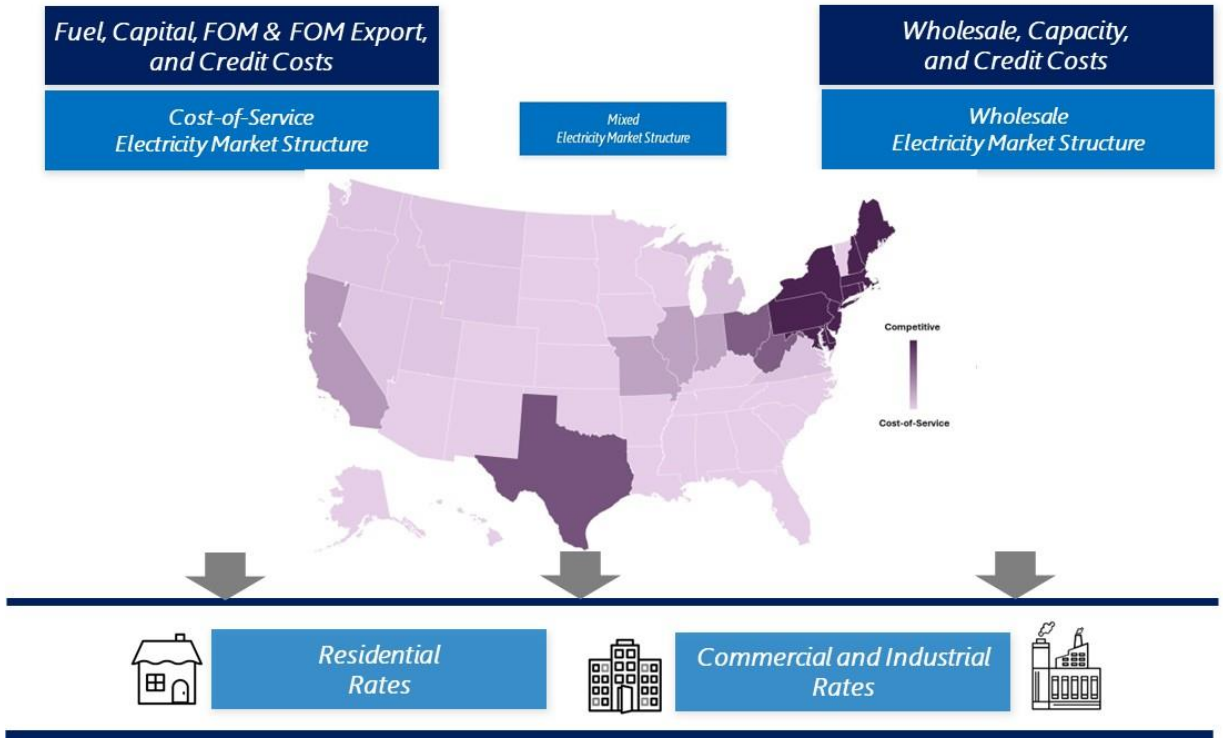
- In a **cost-of-service (COS)** market, electricity prices are set based on the total costs to serve load.
 - The delivered electricity price is based on the cost of service (operating and investment costs of the generating resources in the market region) plus a T&D margin. The cost-of-service components 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 and CES 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 2025 delivered price and the electricity price in 2025 projected by its electricity model. The T&D margin for each ratepayer class is assumed to remain unchanged across the scenarios.
 - The T&D margin in addition to transmission and distribution costs includes non-energy costs such as administration costs, policy program taxes and fees and the utility return.
- 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.

Rate Estimation Methodology



Electricity Model

Rate Model



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