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The Financial Benefit of Coal Power Generation for U.S. Consumers in 2025

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Executive Summary

In 2025, U.S. electricity and natural gas consumers faced mounting affordability pressures as higher natural gas prices, strong electricity demand growth, and infrastructure-related costs pushed utility bills higher across much of the country. Despite these challenges, increased coal generation played a critical role in moderating energy costs by displacing higher-cost natural gas generation and limiting upward pressure on wholesale power and fuel prices. Importantly, **states with continued access to coal generation not only realized the greatest cost-buffering benefits in 2025 but also tend to have some of the lowest retail electricity rates in the United States, reflecting the long-standing role of coal in providing stable, low-cost power.**

This report finds that higher coal utilization in 2025 resulted in total U.S. power-sector and natural gas system benefits of an estimated $30 to $40 billion and lowered average annual residential electricity and natural gas bills by roughly $100 to $150 per household compared with scenarios in which coal generation was constrained. These benefits were most pronounced in regions with significant coal capacity, particularly those exposed to winter peak demand and natural gas price volatility.

Electricity demand in the United States increased by 2.8 percent in 2025 compared with 2024, driven by colder winter conditions, continued electrification, and rapid growth in data center load. At the same time, average natural gas prices delivered to U.S. power plants rose by more than 26 percent year over year, reflecting higher winter demand, lower storage inventories at the end of the heating season, and expanding U.S. LNG exports. Delivered coal prices, by contrast, declined slightly. These market conditions improved the relative competitiveness of coal power plants, resulting in a 12 percent increase in coal generation, or approximately 80 terawatt-hours, compared with 2024 levels.

Energy Ventures Analysis evaluated two counterfactual scenarios in which coal generation in 2025 was constrained to 2024 utilization levels, either on an annual or monthly basis. In both scenarios, reduced coal generation was largely replaced by increased natural gas generation, which raised natural gas consumption, tightened supply-demand balances, and increased regional natural gas and wholesale power prices. These impacts were most acute during the winter months but persisted throughout the year, as higher early-season gas consumption kept prices elevated in the remaining months.

Under these scenarios, total U.S. electricity and natural gas system costs increased by approximately $30 billion to over $40 billion. For residential consumers, this translated into average annual increases in electricity and natural gas bills of approximately $98 under the annual coal-constraint scenario and more than $148 under the monthly-constraint scenario. **States that realized the largest benefits from increased coal generation in 2025**, including those in the Southwest Power Pool and PJM regions, **generally combine higher coal generation shares with some of the lowest retail electricity rates in the country.** Conversely, states without remaining coal capacity exhibited smaller modeled benefits not because they face lower energy costs, but because they lack the operational flexibility to offset rising natural gas prices through fuel switching.

The results underscore the value of coal power generation as a source of operational flexibility and cost containment during periods of elevated natural gas prices. As electricity demand continues to grow and natural gas markets become increasingly influenced by global LNG dynamics, continued coal plant retirements could materially reduce the power system's ability to buffer fuel price volatility, increasing costs and risk for U.S. consumers, particularly during extreme weather events.

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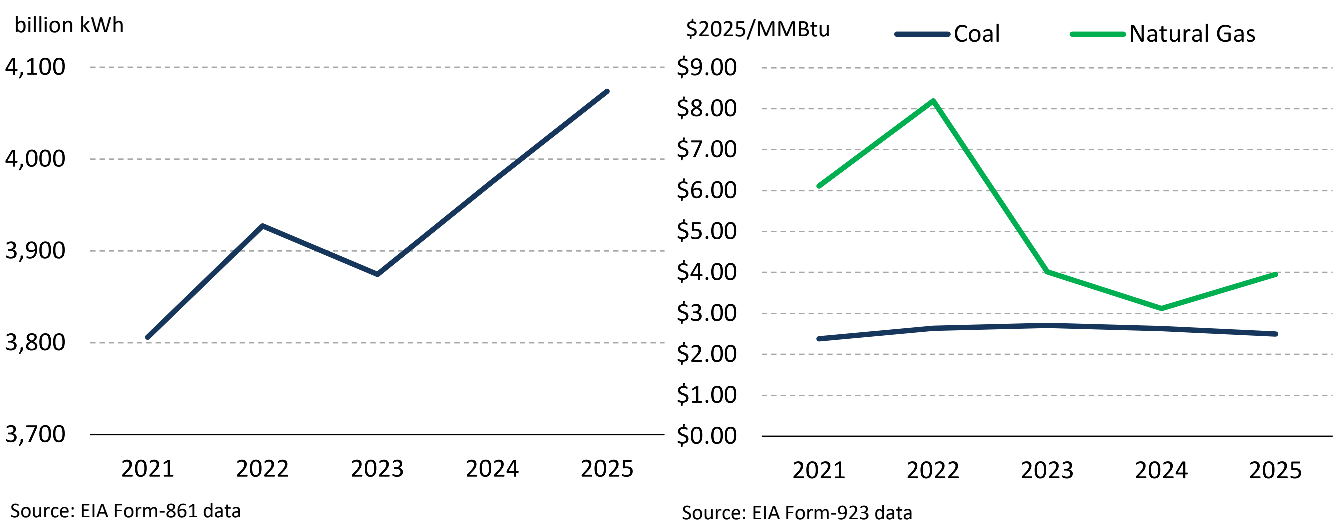
Introduction

In 2025, the United States faced a deepening affordability crisis that affected millions of households nationwide, as persistent high costs for housing, food, healthcare, childcare, and utilities outpaced wage growth, eroding real purchasing power. Over the first 10 months of 2025, the average U.S. residential electric and natural gas bills increased by 6.6 percent and 12.3 percent, respectively, driven by rising electricity demand from data centers and transportation-sector electrification, higher natural gas prices, and transmission and distribution upgrades. However, thanks to increased output from U.S. coal power plants in 2025, both electric and natural gas bills across the country rose at a much lower rate than they would have without the increase in coal power generation. This report aims to estimate the financial benefits of increased coal power generation in 2025 to the U.S. power and natural gas industry and to the average residential electric and natural gas consumer.

In 2025, electricity demand across the United States grew by 2.8 percent over 2024 levels, according to the U.S. Energy Information Administration's (EIA) Hourly Electric Grid Monitor,[1] supported by significant growth in the residential and commercial end-use sectors. A "normal" winter with temperatures near the 10-year average, which supported higher electricity demand for residential and commercial heating during the first quarter of 2025, and increased electricity consumption from electric vehicles and data centers, were the primary reasons for the notable increase in electricity consumption in 2025.

In addition to rising electricity demand, another major factor affecting the U.S. power sector in 2025 was higher natural gas prices. After falling from highs of $8/MMBtu during the 2022 global energy crisis to a low of just over $3/MMBtu in 2024, the average annual cost for natural gas delivered to U.S. power plants rose by over 26% to just under $4/MMBtu, driven by higher demand during the early winter months, resulting in lower natural gas inventories at the end of the traditional natural gas withdrawal season, and growing U.S. LNG exports. Delivered coal prices, on the other hand, declined slightly in 2025 from the previous year.

EXHIBIT 1 - U.S. ELECTRIC RETAIL SALES (LEFT) AND COAL & NATURAL GAS COST DELIVERED TO U.S. POWER PLANTS (RIGHT)



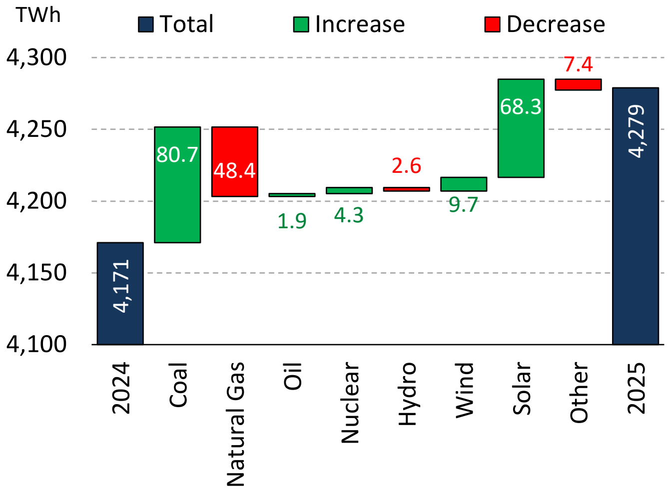
Driven by higher electricity demand and increased competitiveness from higher natural gas prices, coal electricity generation in 2025 rose 12% or 80 TWh year-over-year to about 754 TWh, accounting for about 17.5% of total U.S. electricity generation. Conversely, natural gas power generation declined by almost 50 TWh, or 2.8%, despite overall demand growth. The other resource with significant year-over-year growth was solar power plants, which grew by almost

[1] https://www.eia.gov/electricity/gridmonitor/

70 TWh, or 33%, over 2024 levels, following the estimated connection of 29 GW of new solar power plants to the U.S. electric grid in 2025.

EXHIBIT 2 - YEAR-OVER-YEAR CHANGES IN U.S. ELECTRICITY GENERATION BY FUEL TYPE

			Change	
Category	2025	2024	TWh	%
Coal	754.2	673.5	80.7	12.0%
Natural Gas	1,689.4	1,737.8	-48.4	-2.8%
Oil	7.8	5.9	1.9	32.3%
Nuclear	787.7	783.3	4.3	0.6%
Hydro	248.4	251.0	-2.6	-1.0%
Wind	463.1	453.4	9.7	2.1%
Solar	273.8	205.5	68.3	33.2%
Other	52.1	59.5	-7.4	-12.5%
Total	**4,278.9**	**4,171.0**	**107.9**	**2.6%**



Source: EIA Hourly Electric Grid Monitor

Due to their similar operating characteristics, utilities have traditionally dispatched their coal- and natural gas power plants primarily based on the cost to generate electricity. As the price of natural gas increased, the primary cost factor for electricity generation in natural gas power plants, coal power plants became more cost-competitive and operated at higher utilization rates, displacing their natural gas counterparts. The increased coal consumption was made possible by coal plants maintaining substantial on-site coal inventories, often allowing multi-week operations without resupply, and by the U.S. coal mining industry increasing production. Based on industry estimates, the approximately 43 million tons of increased coal consumption at U.S. coal power plants was met by about 16 million tons from on-site coal inventories and 27 million tons from increased coal deliveries.

Therefore, increased coal generation, supported by on-site coal inventories at coal plants and higher coal production at U.S. coal mines, buffered U.S. electric power and natural gas customers from cost increases driven by rising natural gas prices. This analysis aims to quantify the financial benefits realized by the U.S. power and natural gas sectors from substituting natural gas for coal. Quantifying the financial benefits of electric generation flexibility for U.S. consumers provides insight into the costs and benefits of the existing U.S. coal fleet as electric utilities and state and federal policymakers evaluate possible delays or extensions of coal plant retirements.

Methodology

To quantify the financial benefits realized by U.S. power and natural gas consumers from substituting natural gas for coal, Energy Ventures Analysis (EVA) prepared two alternative scenarios for 2025. Scenario 1 limited each coal power plant's annual electric generation to the level achieved at that plant in 2024, without imposing monthly limits. Scenario 2 limited each coal power plant's monthly generation to the level of the corresponding month in 2024. The two scenarios represent annual and monthly constraints on U.S. coal consumption at power plants due to limited availability of on-site coal inventories, coal deliveries from U.S. coal mines, or both, and represent approximate lower and upper bounds for the financial impacts on U.S. consumers.

EVA used the resulting generation constraints for U.S. coal plants in its hourly economic dispatch model to reanalyze 2025 power-sector operations under each of the two alternative scenarios. EVA maintained the same capacity mix across the Lower-48, including all realized capacity additions and retirements as they occurred in 2025. EVA also included the actual

2025 hourly electricity demand and hourly wind and solar generation by balancing authority. As a result, the only changing factor between the actual 2025 data and the two alternative scenarios is the generation and utilization of existing U.S. dispatchable power plants, including natural gas, coal, oil, and energy storage.[2]

During the first modeling step, EVA estimated the hourly dispatch (i.e., electricity generation) by electric generating units across the Lower-48 in Scenarios 1 and 2. After establishing the new dispatch order and the resulting change in natural gas consumption by power plant, EVA used its Natural Gas Market Model to estimate the change in natural gas price at each regional price point across the Lower-48. Lastly, EVA reinserted the calculated, higher natural gas price into its hourly power dispatch model to determine the resulting change in wholesale power prices by region across the Lower-48.

Once the increased regional natural gas and power prices for 2025 under the two scenarios were calculated, EVA used actual realized electricity and natural gas sales by state to estimate the total increase in revenue requirement for both electricity and natural gas due to the rise in underlying wholesale prices, as well as the impact on the average 2025 residential natural gas and electric power bill by state.

Results

EXHIBIT *3* provides a comparison of actual and modeled 2025 generation levels by fuel type for the U.S. electric power sector. Since EVA maintained actual 2025 load, wind, solar, hydro, and nuclear generation levels, the only changes in generation between actual 2025 data and the two modeled scenarios are limited to fossil-fuel power plants and energy storage resources.

EXHIBIT 3 - ANNUAL LOWER-48 2025 ELECTRIC GENERATION BY FUEL TYPE & SCENARIO (TWH)

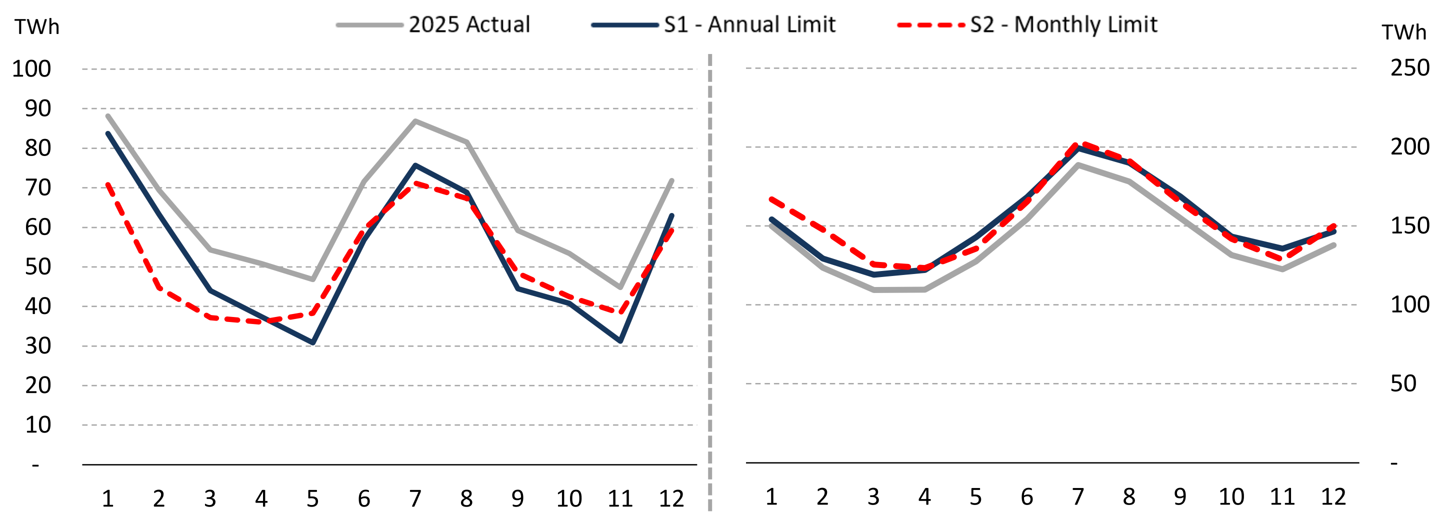
	Actual	Scenario 1 (Annual Limit)			Scenario 2 (Monthly Limit)		
Category	2025	2025	Δ	% Δ	2025	Δ	% Δ
Coal	754.2	619.8	-134.4	-17.8%	594.0	-160.2	-21.2%
Natural Gas	1,689.4	1,821.0	131.6	7.8%	1,846.0	156.6	9.3%
Oil	7.8	11.0	3.2	41.0%	11.8	4.0	51.3%
Nuclear	787.7	787.7	-	-	787.7	-	-
Hydro	248.4	248.4	-	-	248.4	-	-
Wind	463.1	463.1	-	-	463.1	-	-
Solar	273.8	273.8	-	-	273.8	-	-
Other	52.1	54.1	2.0	3.8%	54.1	2.0	3.8%
Total	**4,278.9**	**4,278.8**	**-**	**-**	**4,278.9**	**-**	**-**

In both modeled scenarios, coal generation falls below the 2024 actual level of 673 TWh due to the retirement of coal plants in 2024 and 2025. Notably, coal generation in Scenario 2 fell below 600 TWh because coal plants were limited during high-demand periods in January and February but did not reach their constraints during low-demand periods in the Spring and Fall, resulting in overall lower annual utilization rates than in Scenario 1.

EXHIBIT 4 shows the monthly generation pattern of U.S. coal (left) and natural gas (right) power plants in 2025 and in the two modeled scenarios.

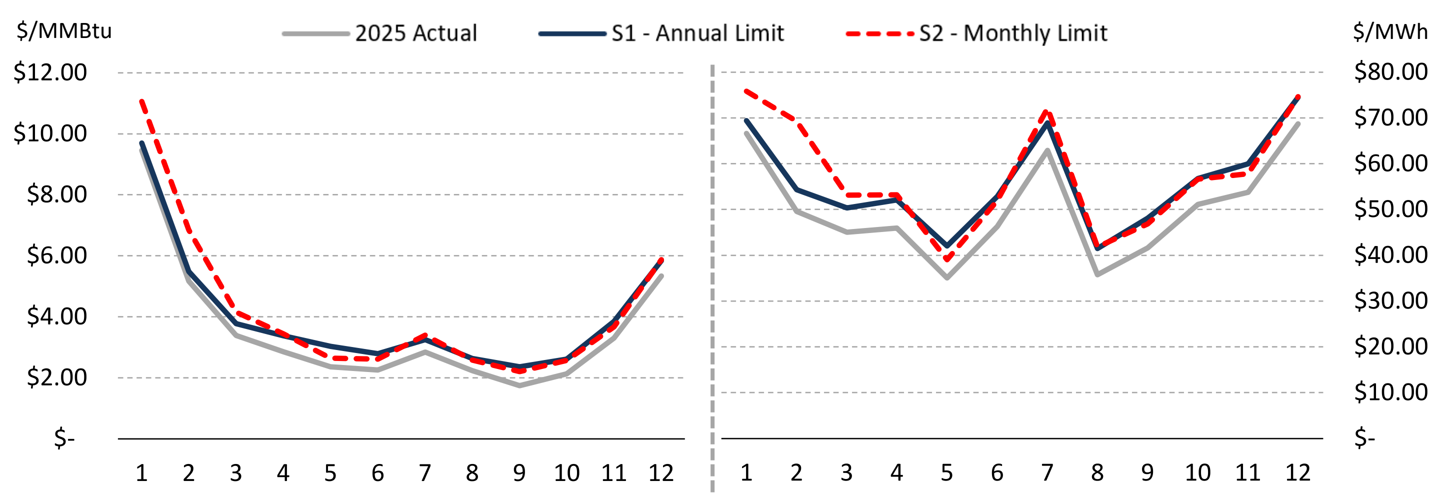
[2] Although generation from hydroelectric dams if often considered "dispatchable," EVA maintained 2025 hydro generation levels as it is often dictated or limited by precipitation, snow melt, and river water levels, among others.

EXHIBIT 4 – MONTHLY LOWER-48 ACTUAL & MODELED 2025 COAL (LEFT) AND NATURAL GAS (RIGHT) GENERATION



Since coal plants' only constraint in Scenario 1 is their annual generation limit, the plants "chose" to operate in the most profitable months (i.e., months with the highest power prices due to supply-demand constraints), namely January and February, when numerous cold spells drove up electricity demand and, in turn, power prices. In Scenario 2, coal plants' generation was limited on a monthly basis, so coal generation during these high-demand periods was significantly reduced. As a result, natural gas generation in Q1 was notably higher than 2025 actuals in Scenario 2, yet similar in Scenario 1. However, the largest shift in natural gas-to-coal generation in both scenarios occurred over the remaining months of the year, as the higher natural gas consumption in Q1 further lowered natural gas inventories exiting the 2024/25 winter period, supporting higher natural gas prices for the remainder of the year. For example, **EXHIBIT 5** shows the monthly shifts in natural gas and power prices at TETCO M-3 (left) and PJM Western Hub (right) in Scenarios 1 and 2 compared to 2025 actual pricing. As stated, the primary price difference between Scenarios 1 and 2 occurred in Q1, with similar elevated pricing levels for the remainder of the year.

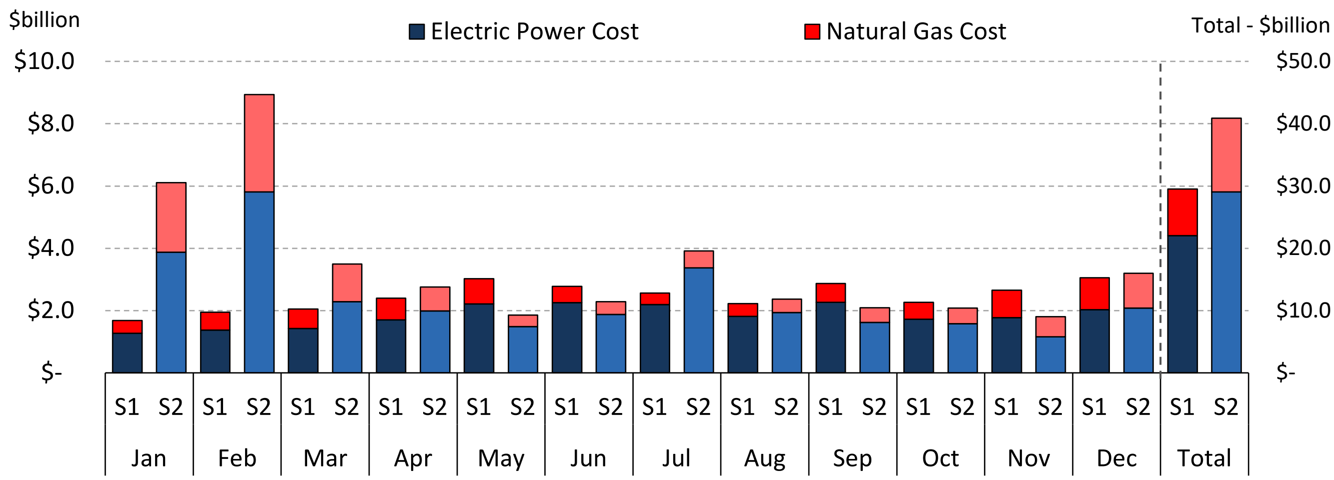
EXHIBIT 5 - AVERAGE MONTHLY SHIFTS IN TETCO M-3 (LEFT) NATURAL GAS & PJM WESTERN HUB (RIGHT) POWER PRICES



Source: S&P Global Platts & EVA Analysis

EVA estimated the overall cost increase by sector by multiplying the resulting shifts in wholesale regional natural gas and power prices by regional natural gas and electric power demand. **EXHIBIT 6** shows the monthly increases in electric power and natural gas costs, as well as the total annual increase in both, anchored to the right-hand axis.

EXHIBIT 6 - ESTIMATED LOWER-48 POWER AND NATURAL GAS COST INCREASE BY SCENARIO



Note: S1 - Annual Limit; S2 - Monthly Limit

Unsurprisingly, the largest monthly increases in electric power and natural gas costs in Scenario 2 occurred in January and February, when coal generation was constrained by 2024 monthly utilization rates, while natural gas demand was at its highest. As a result, any increase in natural gas generation would produce the greatest rise in natural gas prices. In particular, electric power and natural gas costs rose by over $6 billion in January and nearly $9 billion in February in Scenario 2. For the remainder of the year, power and natural gas cost increases averaged around $2 billion per month in both scenarios. The total cost increase in Scenario 1 was estimated at approximately $30 billion, while costs in Scenario 2 totaled over $40 billion for the Lower-48 states.

To estimate the average annual cost increase for residential electric and natural gas customers in the Lower-48 states, EVA calculated the monthly cost increases for electric and natural gas utilities that would need to be recouped through rate increases. EVA applied the same rate increase to each customer class (i.e., residential, commercial, industrial, transportation). Using EIA data on electricity and natural gas costs and consumption levels by state, EVA calculated the average annual cost of natural gas and electricity service for the average U.S. residential consumer and the increase in cost under Scenarios 1 and 2. **EXHIBIT *7*** provides an overview of the average annual cost increase for the average U.S. residential consumer in the Lower-48 states.

EXHIBIT 7 - AVERAGE ANNUAL COST INCREASE IN U.S. RESIDENTIAL ELECTRIC & NATURAL GAS BILLS BY SCENARIO

	2025 Avg. Annual Cost	Scenario 1		Scenario 2	
		$	%	$	%
Power	$ 1,816.08	$ 71.73	3.9%	$ 97.12	5.3%
Natural Gas	$ 1,075.02	$ 25.76	2.4%	$ 50.96	4.7%
Total	**$ 2,891.10**	**$ 97.49**	**3.4%**	**$ 148.08**	**5.1%**

The average annual cost for electricity and natural gas service for the average U.S. residential customer is estimated at approximately $72 and $26 in Scenario 1, and $97 and $51 in Scenario 2, respectively. In Scenario 1, the total cost increase of $98 represents about 40% of one month's electricity and natural gas service. In contrast, in Scenario 2, the cost increase of over $148 represents over 60% of one month's electricity and natural gas service.

However, significant regional differences in cost increases exist. **EXHIBIT 8** and **EXHIBIT 9** show the average annual benefit to residential electric and natural gas customers by state under Scenarios 1 and 2, respectively.

EXHIBIT 8 - AVERAGE ANNUAL BENEFIT TO RESIDENTIAL ELECTRIC & NATURAL GAS CUSTOMERS BY STATE UNDER SCENARIO 1[3]

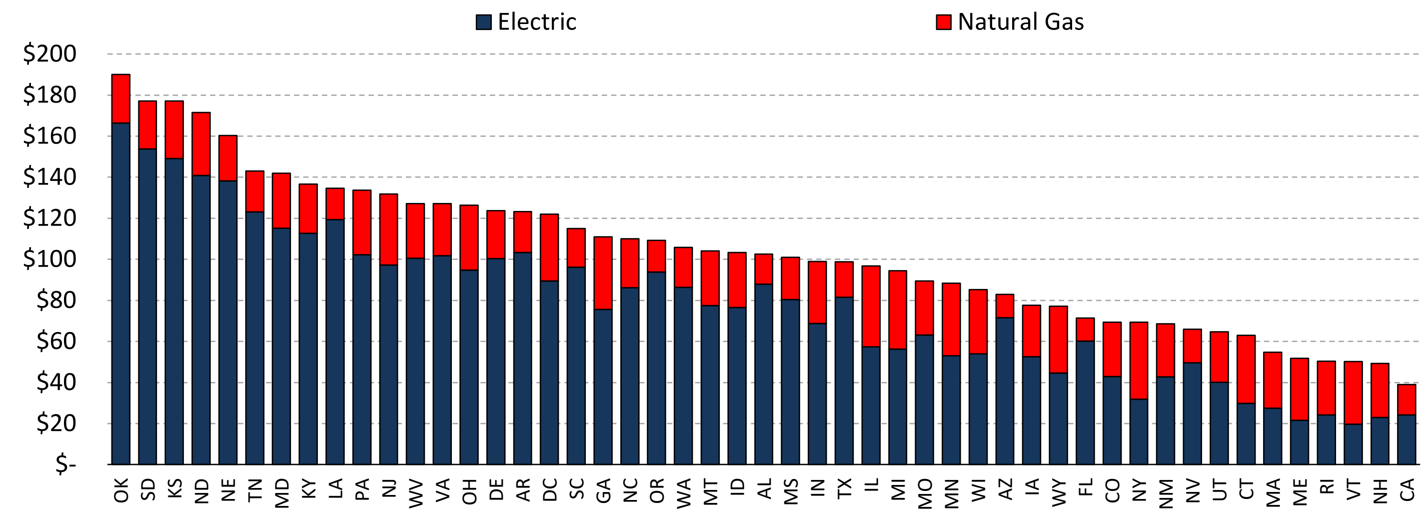
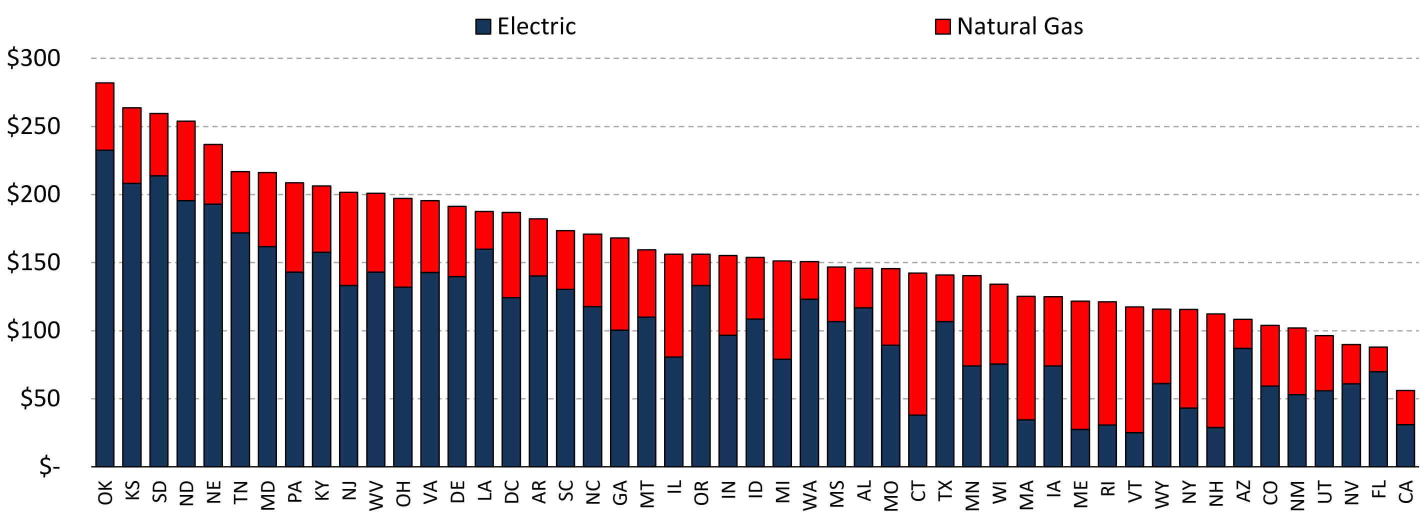


EXHIBIT 9 - AVERAGE ANNUAL BENEFIT TO RESIDENTIAL ELECTRIC & NATURAL GAS CUSTOMERS BY STATE UNDER SCENARIO 2[3]



Unsurprisingly, the largest benefits to residential electricity and natural gas customers occurred in states that participate in wholesale power markets with significant coal and natural gas generation, and that saw a significant shift from natural gas to coal power plants in 2025 as natural gas prices rose. For example, the vast majority of utilities in Oklahoma, Kansas, South Dakota, North Dakota, and Nebraska participate in the Southwest Power Pool (SPP) power market, which saw coal generation increase by over 21% from 2024 to 2025, the highest in the country. Therefore, these states benefited the most in 2025 from the increase in coal generation, which shielded consumers from some of the rise in regional natural gas prices. PJM, which covers most of the states of Maryland, Pennsylvania, New Jersey, West Virginia, Ohio, Virginia, Delaware, and Washington, DC, showed the second-highest increase in coal generation at 19% year over year and

[3] Benefits reflect avoided cost increases from fuel switching and do not indicate absolute electricity price levels by state.

therefore realized some of the greatest financial benefits of increased coal generation in 2025 as natural gas prices increased.

On the other hand, states with little to no remaining coal generation or reduced flexibility in coal power plant output showed the smallest financial benefit. This includes states such as California, New Hampshire, Vermont, Massachusetts, Rhode Island, Maine, Connecticut, New York, and New Mexico, none of which have any active coal plants remaining and are therefore limited in their ability to buffer any increase in natural gas prices.

EXHIBIT 10 shows the estimated annual increase in electricity and natural gas costs to residential customers by state for both scenarios.

EXHIBIT 10 - ESTIMATED ANNUAL RESIDENTIAL ELECTRIC & NATURAL GAS COST BENEFITS BY SCENARIO & BY STATE

	Electric Cost					Natural Gas Cost					Total Cost				
State	2025 Avg. Annual Cost	Scenario 1 $	Scenario 1 %	Scenario 2 $	Scenario 2 %	2025 Avg. Annual Cost	Scenario 1 $	Scenario 1 %	Scenario 2 $	Scenario 2 %	2025 Avg. Annual Cost	Scenario 1 $	Scenario 1 %	Scenario 2 $	Scenario 2 %
Alabama	$ 2,194.83	$ 87.98	4.0%	$ 116.86	5.3%	$ 712.75	$ 14.56	2.0%	$ 28.91	4.1%	$ 2,907.59	$ 102.53	3.5%	$ 145.77	5.0%
Arkansas	$ 1,645.24	$ 103.28	6.3%	$ 140.13	8.5%	$ 1,119.85	$ 20.00	1.8%	$ 42.13	3.8%	$ 2,765.08	$ 123.28	4.5%	$ 182.26	6.6%
Arizona	$ 1,948.44	$ 71.56	3.7%	$ 86.97	4.5%	$ 572.72	$ 11.34	2.0%	$ 21.28	3.7%	$ 2,521.16	$ 82.90	3.3%	$ 108.25	4.3%
California	$ 1,899.52	$ 24.18	1.3%	$ 30.93	1.6%	$ 764.60	$ 14.82	1.9%	$ 25.02	3.3%	$ 2,664.13	$ 39.00	1.5%	$ 55.94	2.1%
Colorado	$ 1,298.03	$ 42.85	3.3%	$ 59.29	4.6%	$ 830.56	$ 26.56	3.2%	$ 44.67	5.4%	$ 2,128.59	$ 69.42	3.3%	$ 103.96	4.9%
Connecticut	$ 2,430.05	$ 29.78	1.2%	$ 38.12	1.6%	$ 1,573.53	$ 33.20	2.1%	$ 104.14	6.6%	$ 4,003.59	$ 62.97	1.6%	$ 142.26	3.6%
Wash., DC	$ 1,657.46	$ 89.50	5.4%	$ 124.26	7.5%	$ 1,561.01	$ 32.57	2.1%	$ 62.51	4.0%	$ 3,218.47	$ 122.07	3.8%	$ 186.77	5.8%
Delaware	$ 1,862.66	$ 100.30	5.4%	$ 139.64	7.5%	$ 1,151.96	$ 23.40	2.0%	$ 51.60	4.5%	$ 3,014.62	$ 123.70	4.1%	$ 191.24	6.3%
Florida	$ 2,031.77	$ 60.12	3.0%	$ 69.83	3.4%	$ 572.92	$ 11.28	2.0%	$ 18.18	3.2%	$ 2,604.69	$ 71.40	2.7%	$ 88.01	3.4%
Georgia	$ 1,885.96	$ 75.67	4.0%	$ 100.41	5.3%	$ 1,871.51	$ 35.32	1.9%	$ 67.65	3.6%	$ 3,757.47	$ 110.99	3.0%	$ 168.07	4.5%
Iowa	$ 1,410.69	$ 52.47	3.7%	$ 74.01	5.2%	$ 764.36	$ 25.08	3.3%	$ 51.06	6.7%	$ 2,175.05	$ 77.55	3.6%	$ 125.08	5.8%
Idaho	$ 1,294.62	$ 76.54	5.9%	$ 108.48	8.4%	$ 577.33	$ 26.80	4.6%	$ 45.42	7.9%	$ 1,871.95	$ 103.34	5.5%	$ 153.90	8.2%
Illinois	$ 1,536.87	$ 57.32	3.7%	$ 80.63	5.2%	$ 1,234.65	$ 39.43	3.2%	$ 75.63	6.1%	$ 2,771.52	$ 96.75	3.5%	$ 156.27	5.6%
Indiana	$ 1,843.30	$ 68.79	3.7%	$ 96.71	5.2%	$ 945.99	$ 30.12	3.2%	$ 58.42	6.2%	$ 2,789.29	$ 98.90	3.5%	$ 155.13	5.6%
Kansas	$ 1,552.20	$ 149.08	9.6%	$ 208.30	13.4%	$ 1,105.24	$ 27.99	2.5%	$ 55.42	5.0%	$ 2,657.45	$ 177.07	6.7%	$ 263.72	9.9%
Kentucky	$ 1,756.98	$ 112.62	6.4%	$ 157.48	9.0%	$ 988.31	$ 23.97	2.4%	$ 48.79	4.9%	$ 2,745.30	$ 136.59	5.0%	$ 206.27	7.5%
Louisiana	$ 1,877.56	$ 119.43	6.4%	$ 159.92	8.5%	$ 658.98	$ 15.19	2.3%	$ 27.61	4.2%	$ 2,536.54	$ 134.62	5.3%	$ 187.53	7.4%
Massachusetts	$ 2,192.22	$ 27.40	1.2%	$ 34.39	1.6%	$ 1,774.26	$ 27.34	1.5%	$ 90.76	5.1%	$ 3,966.49	$ 54.74	1.4%	$ 125.15	3.2%
Maryland	$ 2,157.06	$ 115.17	5.3%	$ 161.71	7.5%	$ 1,241.76	$ 26.70	2.2%	$ 54.50	4.4%	$ 3,398.82	$ 141.87	4.2%	$ 216.21	6.4%
Maine	$ 1,743.90	$ 21.54	1.2%	$ 27.35	1.6%	$ 1,787.57	$ 30.25	1.7%	$ 94.37	5.3%	$ 3,531.47	$ 51.79	1.5%	$ 121.72	3.4%
Michigan	$ 1,507.06	$ 56.24	3.7%	$ 79.07	5.2%	$ 1,048.84	$ 38.17	3.6%	$ 72.17	6.9%	$ 2,555.91	$ 94.40	3.7%	$ 151.24	5.9%
Minnesota	$ 1,414.52	$ 52.96	3.7%	$ 74.22	5.2%	$ 957.44	$ 35.33	3.7%	$ 66.13	6.9%	$ 2,371.97	$ 88.29	3.7%	$ 140.34	5.9%
Missouri	$ 1,704.81	$ 63.06	3.7%	$ 89.45	5.2%	$ 1,291.93	$ 26.35	2.0%	$ 56.17	4.3%	$ 2,996.74	$ 89.41	3.0%	$ 145.61	4.9%
Mississippi	$ 2,005.20	$ 80.46	4.0%	$ 106.76	5.3%	$ 917.52	$ 20.56	2.2%	$ 40.04	4.4%	$ 2,922.72	$ 101.02	3.5%	$ 146.80	5.0%
Montana	$ 1,313.29	$ 77.49	5.9%	$ 110.05	8.4%	$ 708.37	$ 26.60	3.8%	$ 49.31	7.0%	$ 2,021.66	$ 104.08	5.1%	$ 159.36	7.9%
North Carolina	$ 1,719.83	$ 86.25	5.0%	$ 117.74	6.8%	$ 1,177.51	$ 23.76	2.0%	$ 53.07	4.5%	$ 2,897.34	$ 110.01	3.8%	$ 170.81	5.9%
North Dakota	$ 1,457.31	$ 140.83	9.7%	$ 195.57	13.4%	$ 966.05	$ 30.65	3.2%	$ 58.41	6.0%	$ 2,423.36	$ 171.48	7.1%	$ 253.98	10.5%
Nebraska	$ 1,437.74	$ 138.24	9.6%	$ 192.94	13.4%	$ 926.18	$ 22.01	2.4%	$ 43.92	4.7%	$ 2,363.92	$ 160.25	6.8%	$ 236.86	10.0%
New Hampshire	$ 1,845.78	$ 23.01	1.2%	$ 28.95	1.6%	$ 1,332.07	$ 26.19	2.0%	$ 83.43	6.3%	$ 3,177.85	$ 49.20	1.5%	$ 112.38	3.5%
New Jersey	$ 1,777.89	$ 97.26	5.5%	$ 133.28	7.5%	$ 1,284.36	$ 34.50	2.7%	$ 68.32	5.3%	$ 3,062.25	$ 131.77	4.3%	$ 201.60	6.6%
New Mexico	$ 1,189.81	$ 42.73	3.6%	$ 53.11	4.5%	$ 694.97	$ 25.89	3.7%	$ 48.99	7.0%	$ 1,884.77	$ 68.62	3.6%	$ 102.10	5.4%
Nevada	$ 1,365.37	$ 49.62	3.6%	$ 60.94	4.5%	$ 617.08	$ 16.25	2.6%	$ 28.83	4.7%	$ 1,982.45	$ 65.88	3.3%	$ 89.77	4.5%
New York	$ 1,853.78	$ 31.91	1.7%	$ 43.13	2.3%	$ 1,811.46	$ 37.49	2.1%	$ 72.55	4.0%	$ 3,665.24	$ 69.40	1.9%	$ 115.68	3.2%
Ohio	$ 1,760.04	$ 94.79	5.4%	$ 131.95	7.5%	$ 1,369.73	$ 31.64	2.3%	$ 65.15	4.8%	$ 3,129.77	$ 126.43	4.0%	$ 197.09	6.3%
Oklahoma	$ 1,733.82	$ 166.38	9.6%	$ 232.68	13.4%	$ 1,109.58	$ 23.69	2.1%	$ 49.27	4.4%	$ 2,843.40	$ 190.07	6.7%	$ 281.94	9.9%
Oregon	$ 1,588.68	$ 93.74	5.9%	$ 133.12	8.4%	$ 904.48	$ 15.51	1.7%	$ 22.91	2.5%	$ 2,493.16	$ 109.25	4.4%	$ 156.04	6.3%
Pennsylvania	$ 1,907.68	$ 102.27	5.4%	$ 143.01	7.5%	$ 1,314.18	$ 31.44	2.4%	$ 65.53	5.0%	$ 3,221.85	$ 133.72	4.2%	$ 208.55	6.5%
Rhode Island	$ 1,961.13	$ 24.19	1.2%	$ 30.76	1.6%	$ 1,482.55	$ 26.18	1.8%	$ 90.56	6.1%	$ 3,443.69	$ 50.37	1.5%	$ 121.33	3.5%
South Carolina	$ 1,903.08	$ 96.08	5.0%	$ 130.28	6.8%	$ 808.81	$ 18.87	2.3%	$ 43.13	5.3%	$ 2,711.89	$ 114.95	4.2%	$ 173.41	6.4%
South Dakota	$ 1,593.04	$ 153.75	9.7%	$ 213.78	13.4%	$ 701.79	$ 23.40	3.3%	$ 45.64	6.5%	$ 2,294.83	$ 177.14	7.7%	$ 259.42	11.3%
Tennessee	$ 1,916.73	$ 123.03	6.4%	$ 171.80	9.0%	$ 741.07	$ 20.02	2.7%	$ 45.02	6.1%	$ 2,657.80	$ 143.04	5.4%	$ 216.82	8.2%
Texas	$ 2,121.72	$ 81.58	3.8%	$ 106.67	5.0%	$ 937.26	$ 17.22	1.8%	$ 34.34	3.7%	$ 3,058.98	$ 98.81	3.2%	$ 141.00	4.6%
Utah	$ 1,220.89	$ 40.15	3.3%	$ 55.77	4.6%	$ 700.63	$ 24.56	3.5%	$ 40.66	5.8%	$ 1,921.51	$ 64.71	3.4%	$ 96.42	5.0%
Virginia	$ 1,904.99	$ 101.78	5.3%	$ 142.81	7.5%	$ 1,187.10	$ 25.32	2.1%	$ 52.72	4.4%	$ 3,092.09	$ 127.10	4.1%	$ 195.53	6.3%
Vermont	$ 1,600.26	$ 19.74	1.2%	$ 25.10	1.6%	$ 1,561.14	$ 30.52	2.0%	$ 92.34	5.9%	$ 3,161.40	$ 50.25	1.6%	$ 117.44	3.7%
Washington	$ 1,467.92	$ 86.39	5.9%	$ 123.00	8.4%	$ 1,210.83	$ 19.36	1.6%	$ 27.82	2.3%	$ 2,678.74	$ 105.75	3.9%	$ 150.83	5.6%
Wisconsin	$ 1,438.54	$ 53.90	3.7%	$ 75.48	5.2%	$ 800.12	$ 31.28	3.9%	$ 58.63	7.3%	$ 2,238.66	$ 85.18	3.8%	$ 134.11	6.0%
West Virginia	$ 1,906.71	$ 100.54	5.3%	$ 142.94	7.5%	$ 1,028.04	$ 26.65	2.6%	$ 58.03	5.6%	$ 2,934.75	$ 127.19	4.3%	$ 200.97	6.8%
Wyoming	$ 1,339.52	$ 44.65	3.3%	$ 61.18	4.6%	$ 1,231.12	$ 32.58	2.6%	$ 54.68	4.4%	$ 2,570.63	$ 77.23	3.0%	$ 115.86	4.5%

Notably, the states that received the greatest benefit from the natural gas-to-coal switching in 2025 also have some of the lowest electricity rates in the country and derive a significant share of their electricity from coal power plants. For example, North Dakota and Nebraska, two states whose residential electric and natural gas customers enjoyed some of the greatest benefits from natural gas-to-coal switching in 2025, also had the lowest and 4th-lowest average retail electricity rates in 2025, respectively, while their in-state coal generation share ranked in the top 10 among all U.S. states. On the other hand, the two states with the estimated lowest benefit from the natural gas-to-coal switching in 2025 are New Hampshire and California, whose 2025 average retail electricity rates and in-state coal generation shares rank near or at the bottom compared with all other U.S. states.

Taken together, the results show **that increased coal power generation in 2025 delivered a material economic benefit to U.S. electricity and natural gas consumers by limiting both wholesale power prices and natural gas price escalation during a period of rising demand and higher fuel costs. The analysis indicates that constraining coal generation to 2024 utilization levels would have added $30 to $40 billion in nationwide power-sector and natural gas system costs**, with a disproportionate impact during winter peak months when system flexibility is most valuable. Regions with meaningful coal capacity were better positioned to absorb higher natural gas prices, while states without remaining coal resources had limited ability to buffer these cost pressures. As electricity demand continues to grow and natural gas markets tighten, the loss of dispatchable coal capacity through future retirements would reduce system flexibility and increase exposure to fuel price volatility, particularly during periods of extreme weather, with direct implications for consumer affordability.

Limitations and Considerations

This analysis is subject to several important considerations that should be taken into account when interpreting the results.

First, the scenarios evaluated in this report isolate the impact of coal generation constraints while holding all other system variables constant. Actual electricity markets are influenced by a wide range of dynamic factors, including generator outages, transmission constraints, consumer behavioral responses, and evolving utility fuel procurement strategies. As such, real-world outcomes may differ from modeled results.

Second, the modeling framework assumes that increases in wholesale electricity and natural gas costs are fully recovered through uniform rate increases across customer classes. In practice, regulatory structures, rate design, fuel adjustment mechanisms, and the timing of rate cases can affect both the magnitude and distribution of cost impacts among residential, commercial, and industrial customers.

Third, the analysis focuses on short-run operational impacts and does not account for potential longer-term investment responses, such as accelerated deployment of new generation, storage, demand-side resources, or transmission infrastructure. Over longer time horizons, such investments could partially offset the loss of coal generation, though often at higher capital costs and with longer development timelines.

Fourth, environmental compliance costs, emissions externalities, and policy-driven constraints beyond those reflected in actual 2025 operations are not explicitly modeled. As a result, the results reflect observed market behavior under existing regulatory conditions rather than prospective policy scenarios.

Finally, coal generation in 2025 benefited from substantial on-site fuel inventories and a responsive domestic coal supply chain. As coal capacity declines and inventories shrink, future system conditions may exhibit reduced operational flexibility, amplifying the cost impacts of fuel price volatility relative to those observed in 2025.

