CNG

Deferred Gas Cost Summary

Connecticut Natural Gas Corporation **Page 1 of 1**
Docket No. 26-10-01

Calculation of Net Deferred Gas Costs

Exhibit 10

Net Deferred Gas Costs	($2,721,832)
Remainder of Deferred Gas Costs from 8-31-25 prior deferred year	$878,356
Total Deferred Gas Costs	($1,843,476)
Divided by:	
Sales (CCF) from 10/1/24 to 8/31/25	313,483,340
Firm Deferred Gas Billing Factor	($0.0059)

Connecticut Natural Gas Corporation
Docket No. 26-10-01

Annual Deferred Gas Costs Summary - Attachment
For the Twelve Month Period September 2025 through August 2026

Part of Deferred Line Ref #.	PURCHASED GAS COSTS	September 2025	October 2025	November 2025	December 2025	January 2026	February 2026	March 2026	April 2026	May 2026	June 2026	July 2026	August 2026	Total
1	Algonquin Gas Pipeline Cashout	$ (20,970.63)	$ 14,489.66	$ 137,317.42	$ 700,939.78	$ 2,018,306.13	$ 511,514.76	$ 204,215.60	$ -	$ (19,350.13)	$ 4,867.09	$ 1,578.30	$ -	$ 3,552,907.98
2	Tennessee Gas Pipeline (TGP) Cashout	$ (12,026.40)	$ (118,203.47)	$ -	$ 151,266.01	$ 290,499.40	$ 114,727.07	$ 149,504.70	$ -	$ (1,463.78)	$ 955.97	$ (58,671.81)	$ 2.71	$ 516,590.40
39	Marginal Cashout	$ -	$ -	$ 95,101.30	$ -	$ -	$ -	$ -	$ (18,006.42)	$ -	$ 20,058.42	$ -	$ 26,569.69	$ 123,722.99
	Total Intercompany Transfers	$ (32,997.03)	$ (103,713.81)	$ 232,418.72	$ 852,205.79	$ 2,308,805.53	$ 626,241.83	$ 353,720.30	$ (18,006.42)	$ (20,813.91)	$ 25,881.48	$ (57,093.51)	$ 26,572.40	$ 4,193,221.37

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Invoices for September 2025 – August 2026

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Filed under protective order.

CNG

Docket No. 99-10-01

Order No. 1

Directives

Connecticut Natural Gas Corporation
Docket No. 26-10-01

Order No. 1 of the final decision in Docket No. 99-10-01 states: Beginning with Docket No. 04-04-01, each LDC shall provide items that were discussed in Section II C, in its semi-annual PGA filing.

Section II.C Future Filings

To expedite the Department's review the LDCs must:

1) Provide the references to the invoice data for all corresponding expenses shown in the gas cost summaries. Each invoice should clearly show how the total was determined, and whether or not the invoice total equals the corresponding gas cost summary total for each supplier.

   Response: Notations have been made on the face of the supplier invoices which clearly show how the total was determined and how it relates to the corresponding gas cost summary total for each supplier. The number circled denotes the line on the corresponding Annual Deferred Gas Costs Summary schedule.

2) Identify and explain any difference between the invoice and the deferred gas cost summary.

   Response: Notations have been made on the face of the supplier invoices that explain when the invoice total does not equal the corresponding gas cost summary total.

3) Identify and explain any capacity turnbacks and new replacement contracts.

   Response: There were no capacity turnbacks during the PGA period.

4) Show and compare the cost associated with capacity no longer under contract against the cost under replacement contracts.

   Response: There were no capacity turnbacks during the PGA period.

In addition, Docket No. 99-10-01 requires each LDC to submit the following items with every semi-annual PGA filing beginning with Docket No. 00-04-01:

1) Identification of all affiliate transactions that affect the gas supply that occurred during the PGA period.

   Response: There were no affiliate transactions other than related to balancing of the joint Operational Balancing Agreements with pipelines. This is a long-standing

Connecticut Natural Gas Corporation
Docket No. 26-10-01

Section II. C Future Filings (continued)

balancing arrangement. The balancing volumes were exchanged at cost between CNG and SCG, both of which are under the Department's jurisdiction.

There were no CNG affiliate transactions with any other affiliate.

2) An exhibit that shows the percentage and dollar amount of spot market gas costs for each month in the PGA period.

Response: The term "spot market" gas prices is a term within the broad gas industry meaning "market" and "index" prices, with the terms used interchangeably. There are three main categories of market prices- daily and monthly and NYMEX basis. The generally accepted sources of such market prices are Platt's Gas Daily and Inside FERC Gas Market Report, reporting daily ad monthly prices, respectively, at various market production and hub locations in North America. There are also electronically transacted market prices and futures prices all providing information about market prices that are considered in the aforementioned "market" prices.

During the period of September 1, 2025 to August 31, 2026, all of CNG's supply was acquired at market prices therefore please refer to PGA filing details and supplier invoices for the commodity cost information for gas purchases. In terms of percentages approximately 79% of CNG's annual purchases are monthly market based the balance are daily priced with the relative amount varying based upon time of year and market conditions. Most of the supplies were acquired at the Marcellus production locations of Texas Eastern Gas Transmission M2, Tennessee Gas Pipeline 300 line and 200 line and Millennium Pipeline east pool. Additional gas was acquired, primarily in the winter, at the Dawn, Ontario major market hub and to a minor extent at upstream pipeline interconnects sources.

3) Copies of all outside gas supply forecasts purchased or used by the Company in the PGA period.

Response: The Company relies on the vast amount of information and internal employee expertise for forecasting purposes. Some examples of the information used by the Company in forecasting are: various US Department of Energy EIA (Energy Information Administration) data, information and publications; various Canadian National Energy Board data, information and publications; Gas Daily, Oil & Gas journal and other publications/articles; Intercontinental Exchange prices; Canadian Natural Gas Exchange price; NYMEX prices; data and news; and various energy forecasts and data provided by energy trading companies, wholesale marketers, producers, banks and market analysts. Additional market intelligence is

Connecticut Natural Gas Corporation
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Section II. C Future Filings (continued)

gathered from various natural gas market participants regarding current and anticipated trends. See **Directive No. 3 Attachment** for an example of an article from one of the above publications.

4) The source of the Connecticut weather forecast, including all assumptions, used in the filing.

Response: CNG uses normal and design weather and design day for its load forecasting. Normal weather is based on a 30-year average as recorded by the National Oceanic an Atmospheric Administration (NOAA).

Also see **Directive No. 4 Attachment** for samples of weather forecasting information from Atmospheric G2, a weather service which provides forecasts for CNG that correspond to a gas day and include effective degree days as well. These are received by CNG's Gas Control Department four times a day and are used for daily sendout forecasting.

CNG also extensively uses data from NOAA and the National Weather Service. Longer-term forecasts are available from NOAA. Information for seasonal outlooks from the Climate Prediction Center is included in the attachment as well.

5) The average residential customer's gas bill for each month during the PGA period based on 150 ccf per month, stating assumptions, used in the filing.

Response: See **Directive No. 5 Attachment** for the average residential customer's gas bill for each month during the PGA period based on 150 ccf per month.

6) A discussion and evidence of the Company's strategy to obtain the least cost gas for firm ratepayers for storage use.

Response: See **Directive No. 6 Attachment** for a discussion and evidence of the Company's strategy to obtain the least cost gas for firm ratepayers and storage use.

CNG

Docket No. 99-10-01

Directive No. 3 Attachment

Outside Gas Supply Forecasts

Independent Statistics and Analysis
U.S. Energy Information Administration

Short-Term Energy Outlook

September 2026



September 2026

The U.S. Energy Information Administration (EIA), the statistical and analytical agency within the U.S. Department of Energy (DOE), prepared this report. By law, our data, analyses, and forecasts are independent of approval by any other officer or employee of the U.S. Government. The views in this report do not represent those of DOE or any other federal agencies. The Short-Term Energy Outlook (STEO) is prepared in accordance with sections 52(b) and 57(a)(1) of Federal Energy Administration Act of 1974, as amended, and section 1245(d(4)(A) of the National Defense Authorization Act (NDAA) for Fiscal Year 2021, as amended.

September 2026

Short-Term Energy Outlook

Overview

U.S. energy market indicators	2025	2026	2027
Brent crude oil spot price (dollars per barrel)	**$69**	**$91**	**$74**
Retail gasoline price (dollars per gallon)	**$3.10**	**$3.84**	**$3.35**
U.S. crude oil production (million barrels per day)	**13.7**	**13.8**	**14.3**
Natural gas price at Henry Hub (dollars per million British thermal units)	**$3.53**	**$3.43**	**$3.28**
U.S. liquefied natural gas gross exports (billion cubic feet per day)	**15**	**17**	**19**
Shares of U.S. electricity generation			
Natural gas	40%	40%	40%
Coal	17%	16%	14%
Nuclear	18%	18%	18%
Conventional hydropower	6%	6%	6%
Wind	11%	11%	12%
Solar	7%	8%	9%
Other energy sources	1%	1%	1%
U.S. GDP (percentage change)	**2.1%**	**2.1%**	**2.4%**
U.S. CO_2 emissions (billion metric tons)	**4.9**	**4.8**	**4.8**

Data source: U.S. Energy Information Administration, *Short-Term Energy Outlook,* September 2026
Note: Values in this table are rounded and may not match values in other tables in this report.

- **Global oil market assumptions.** We forecast oil production in the Middle East will rise in the coming months because of gradually increasing flows through the Strait of Hormuz and the use of alternative routes out of the region, according to our September 2026 Short-Term Energy Outlook (STEO). However, we assume some constraints to exporting oil from the Middle East will persist through the end of the year, which keeps crude oil production in the region below pre-conflict averages until the second quarter of 2027 (2Q27).
- **Global oil prices.** Global oil prices rose to an average of $91 per barrel (b) in August, $7/b higher than in July. Prices remain elevated in response to falling global oil inventories, which we estimate have decreased by 400 million barrels so far this year. We expect inventories will continue falling through the end of 2026, which will keep prices near the August monthly average in the coming months. We now forecast the Brent crude oil spot price to average around $90/b in 2H26. As oil production rises into next year, and as inventories rebuild, we expect the Brent spot price to gradually fall to an average of $74/b in 2027.
- **Distillate fuel oil inventories**. We forecast U.S. distillate fuel oil inventories will drop below 100 million barrels in September and will remain below the five-year (2021–2025) low through much of 2027. Tightness in the global distillate market has raised domestic prices and incentivized U.S.

exporters to increase distillate exports. We assume global production of distillate fuel will remain below last year's levels in the coming months, contributing to low U.S. diesel inventories and high diesel prices.

- **Natural gas storage**. U.S. natural gas inventories are on track to be above the five-year average at the start of winter. We forecast natural gas inventories will total 3,969 billion cubic feet on October 31, 2026—the end of the injection season—5% above the five-year average. Rising natural gas production in the Permian and Haynesville regions has supported inventory builds over the summer.

- **Electricity demand.** The United States uses record amounts of electricity in our forecast. We expect electricity sales in the United States to total 4,135 billion kilowatthours (BkWh) in 2026 and 4,211 BkWh in 2027, driven by data center development and increased manufacturing activity in the commercial and industrial sectors. Despite a pause in connecting new data center projects in Texas to the grid, the West South Central region accounts for the largest share of total electricity sales growth in our forecast.

- **Forecast timeline**. We finalized inputs into the model on September 3, 2026. This month's forecast does not specifically account for market events after that day.

Notable forecast changes

Current forecast: September 9, 2026; previous forecast: August 11, 2026	**2026**	**2027**
Distillate crack spread (dollars per gallon)	**$1.57**	**$1.25**
Previous forecast	$1.30	$0.97
Percentage change	20.8%	28.5%
Retail diesel price (dollars per gallon)	**$5.07**	**$4.40**
Previous forecast	$4.85	$4.07
Percentage change	4.4%	8.2%
West South Central region electricity sales (billion kilowatthours)	**761**	**790**
Previous forecast	765	829
Percentage change	-0.5%	-4.7%

Data source: U.S. Energy Information Administration, *Short-Term Energy Outlook*
Note: Percentages and changes are calculated from unrounded values.

September 2026

Global Oil Markets

Global oil prices

The Brent crude oil spot price increased to an average of $91 per barrel (b) in August, $7/b higher than in July. Global crude oil prices rose in August as total exports out of the Middle East remained constrained, leading to more oil production shut-ins in the region. This is due, in part, to the renewal of the U.S. blockade on Iran's oil exports following Iran's attacks on tankers in the Strait of Hormuz, as well as because of a new rounds of sanctions from the Treasury Department's Office of Foreign Assets Control against Iranian economic and oil interests. We expect these policies to restrict Iran's oil exports and reduce its oil production.

In addition, attacks on Saudi Arabia's oil exports through the Bab el-Mandeb strait, a major world oil transit chokepoint, reduced oil exports departing from Saudi Arabia's Yanbu port on the Red Sea, a route which bypasses the Strait of Hormuz. In August, exports out of Yanbu were down by about half from July, according to estimates from Vortexa. In response, Saudi Arabia has increased oil shipments through the Suez Canal at the north end of the Red Sea, a longer and costlier route for customers in Asia. Although Saudi Arabia has also reportedly begun to use a series of ship-to-ship transfers outside of the Persian Gulf, we expect that the constrained Red Sea shipping channel will limit Saudi Arabia's supply in the near term until global shipping flows adjust.

Table 1. Estimated Strait of Hormuz closure-related disruptions in crude oil production
thousand barrels per day

Country	Production Feb-26	Estimated shut-ins Mar–June-26 Average	Estimated shut-ins Jul-26	Estimated shut-ins Aug-26	Forecast shut-ins 3Q26	Forecast shut-ins 4Q26	Forecast shut-ins 1Q27
Kuwait	2,560	1,648	850	680			
UAE	3,600	925	0	0			
Iran	3,390	455	200	1,000			
Iraq	4,400	2,880	1,720	1,160			
Qatar	557	463	150	200			
Bahrain	193	143	110	130			
Saudi Arabia	10,500	2,923	1,950	3,550			
Total	**25,200**	**9,435**	**4,980**	**6,720**	**6,230**	**5,663**	**2,717**

We only forecast aggregate disruptions for future months.

Data source: U.S. Energy Information Administration, *Short-Term Energy Outlook*, September 2026

As flows through the Strait of Hormuz and the Bab el-Mandeb strait remain constrained and variable, crude oil production shut-ins rose over the past month. We assess that crude oil production shut-ins averaged 6.7 million barrels per day (b/d) in August, up from 5.0 million b/d in July. We assume that oil flows from the Middle East remain constrained through the fourth quarter of 2026 (4Q26), leading to shut-in production volumes averaging 5.7 million b/d during that quarter.

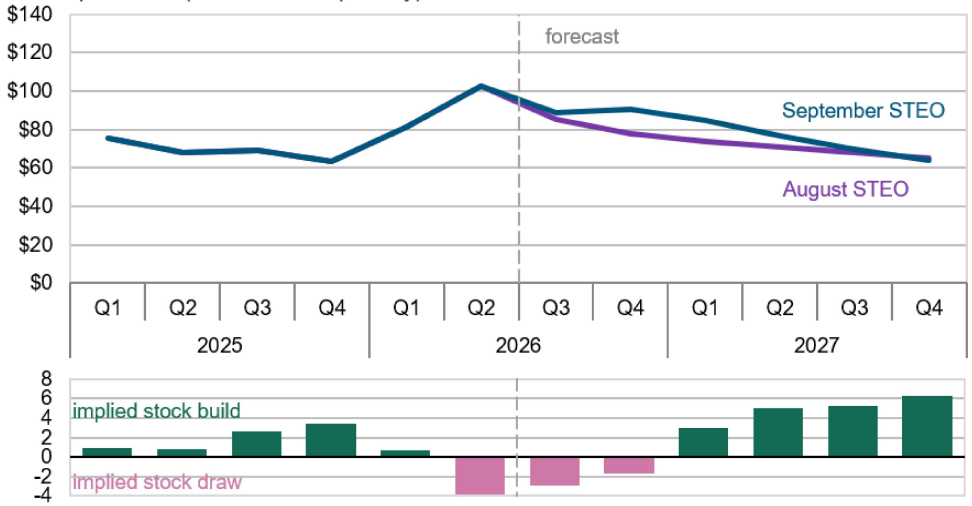
Although we raised our forecast for production disruptions in coming months, we expect oil flows out of the Middle East will gradually increase as shippers continue to find workarounds that allow them to

export oil from the Middle East: using pipeline and overland bypass routes, increasing ship-to-ship transfers, and using new bypass pipeline capacity in the United Arab Emirates, expected to come online in mid-2027. If these assumptions hold, we expect it will take until 2Q27 for most production and trade flows to return to pre-conflict averages. We anticipate, however, that some producers around the Persian Gulf will not be able to bring oil output back to pre-conflict averages during the forecast period.

Because of the large drawdown in global inventories driven by continued disruptions of crude oil production, we forecast that oil prices will remain elevated until global oil flows return to normal and oil inventories can be replenished. We estimate that global oil inventories fell by an average of 3.9 million b/d in 2Q26 and that they will fall by an additional 3.0 million b/d on average in 3Q26 and 1.7 million b/d on average in 4Q26. As a result, we forecast the Brent crude oil spot price will average around $90/b in the second half of 2026 (2H26), $8/b higher than in last month's STEO.

As exports from the Middle East gradually increase and shut-in oil production restarts, we forecast oil prices will begin to fall, decreasing to an average of $77/b by 2Q27. We assess that most shut-in oil production will be largely restored in 2H27 and that global oil inventories will again start building, gradually lowering oil prices to an average of $67/b in 2H27, similar to last month's STEO. However, we expect continued volatility in flows both through the Strait of Hormuz and through alternative routes based on changing conditions in the conflict, which will likely lead to more volatility in short-term price movements than our forecast indicates.

Brent crude oil spot price and global inventory changes
dollars per barrel (million barrels per day)



Data source: U.S. Energy Information Administration, *Short-Term Energy Outlook* (STEO), September 2026

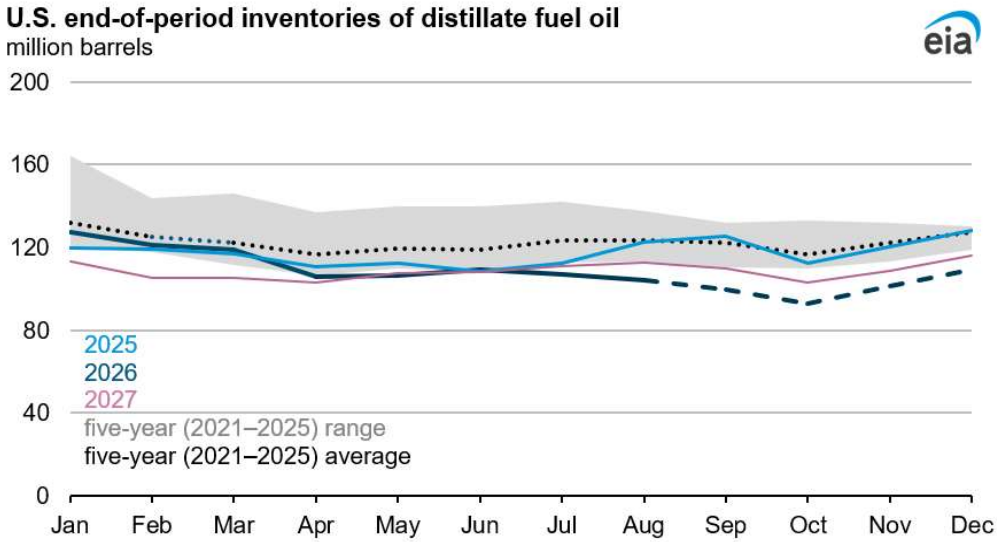
U.S. Petroleum Products

U.S. distillate inventories

We forecast inventories of distillate fuel oil—often sold as diesel—in the United States to fall below 100 million barrels in September and remain below the five-year (2021–2025) low through the end of 2026 and most of 2027. Distillate inventories fell below the five-year range in April, coinciding with high U.S.

September 2026

net exports of the fuel following the loss of large amounts of distillate supply from the Middle East, Russia, and China. The low inventories are reflected in global distillate prices, which have increased throughout the summer in response to lower international refinery production of distillate fuel oil.



Data source: U.S. Energy Information Administration, *Short-Term Energy Outlook*, September 2026

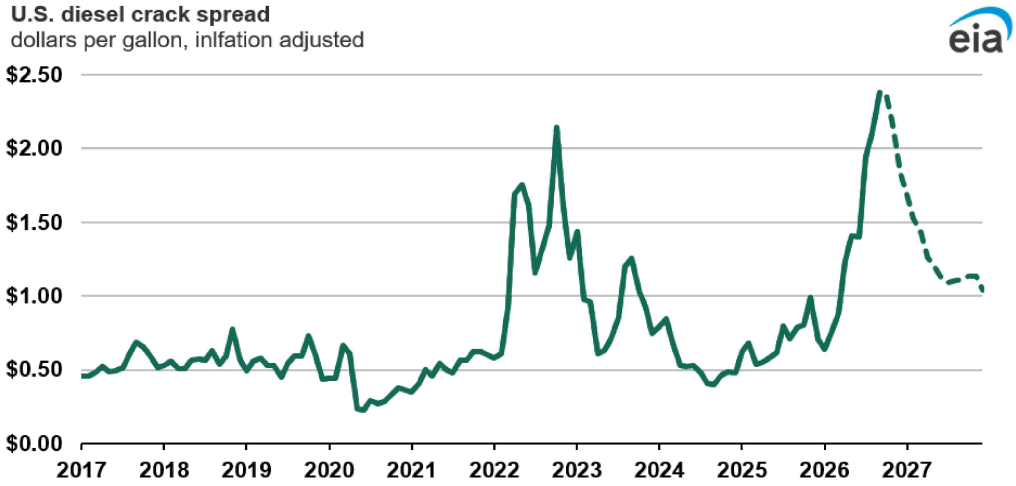
Tightness in the global distillate market raises global prices for distillate and incentivizes U.S. exports of distillate. In the STEO, we assume that global production of distillate fuel will remain below last year's levels in the coming months, which contributes to our forecast of higher net exports of distillate.

Net exports of distillate have been above or near the five-year high in every month of 2026 since February. Low distillate inventories contribute to higher domestic diesel prices. We expect this effect will be particularly pronounced because of seasonal drops in distillate production and seasonal increases in distillate consumption during the fall and winter. Distillate production typically decreases during the fall refinery maintenance season while harvest-season agricultural demand for distillate increases. Low inventories may also contribute to higher prices for residential heating oil in the Northeastern United States.

U.S. diesel crack spreads

We estimate U.S. average diesel crack spreads to exceed $2 per gallon from August through November, before decreasing steadily through mid-2027. This decrease assumes a return to normal tanker traffic through the Strait of Hormuz in the near term, allowing refineries in Saudia Arabia and Kuwait to increase exports of distillate to the global market. We also expect the return of free-flowing crude oil through from the Middle East will improve the availability of crude oil supplies to East Asian refiners, who may increase production, thereby further contributing to lower international crack spreads. If the flows out of the Middle East remain constrained beyond the end of 2026, we would expect to see higher distillate crack spreads globally than what is included in our current forecast. Global distillate prices face

additional upward pressure from the loss of refinery activity in Russia. We estimate that those refinery outages will continue to affect the global market through the first half of 2027.



Data source: U.S. Energy Information Administration, *Short-Term Energy Outlook*, September 2026
Note: The distillate crack spread is calculated as subtracting the cost of a gallon of crude oil from the cost of a gallon of diesel.

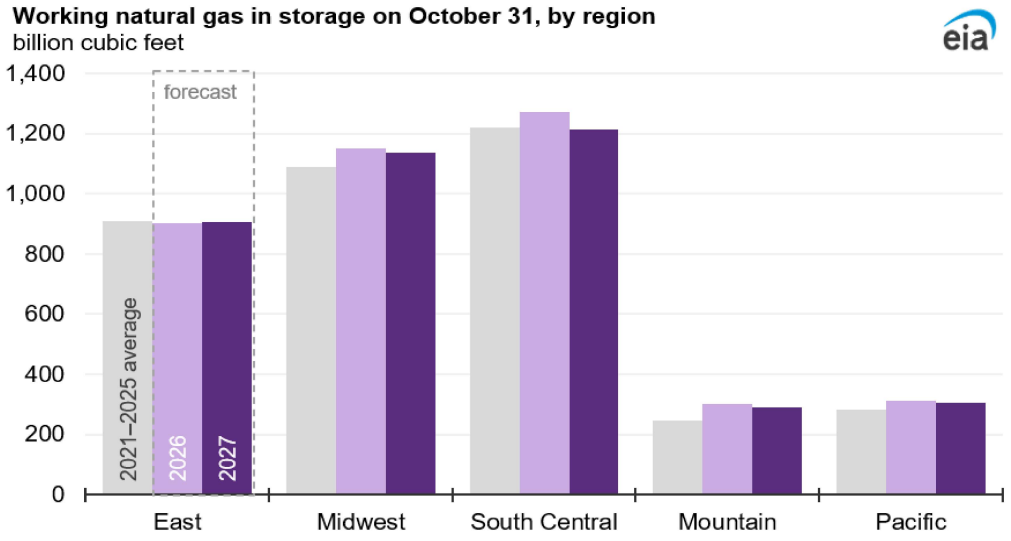
Natural Gas

Natural gas storage

U.S. natural gas inventories are set to be relatively high heading into the winter heating season. We forecast U.S. working natural gas inventories will total 3,969 billion cubic feet (Bcf) on October 31, 2026, 5% above the previous five-year average (2021–2025) and 1% above October 2025 levels. Relatively high inventories in part reflect strong growth in natural gas production in recent months. Regional balances vary entering the withdrawal season (November—March), with inventories in the Mountain region at 21% above their five-year average, followed by the Pacific at 10%, the Midwest at 6%, and South Central at 4%. Inventories in the East are expected to enter the withdrawal season about equal to the five-year average.

Lower relative inventories in the East largely stem from a lower starting point for the injection season relative to the other regions and more limited regional production growth. Inventories in the region began the injection season 11% below the five-year average, following relatively large winter withdrawals owing to colder-than-normal weather. Although Appalachian natural gas production remains near record highs, its growth has been slower this year compared with other regions.

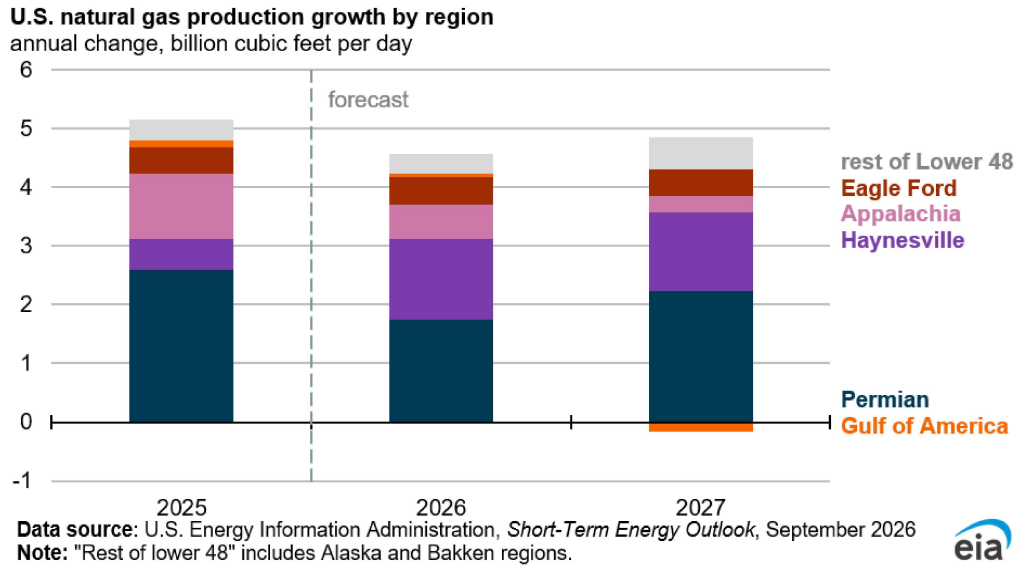
September 2026



Data source: U.S. Energy Information Administration, *Short-Term Energy Outlook*, September 2026

Natural gas production

U.S. marketed natural gas production continues to grow in our forecast, providing additional supply to meet demand and support storage additions. Production increases by 4.5 billion cubic feet per day (Bcf/d) in 2026 and 4.6 Bcf/d in 2027. The Permian and Haynesville regions together account for more than 70% of production growth in our forecast.



Data source: U.S. Energy Information Administration, *Short-Term Energy Outlook*, September 2026
Note: "Rest of lower 48" includes Alaska and Bakken regions.

Permian production in our forecast grows by 1.7 Bcf/d in 2026 and 2.2 Bcf/d in 2027. Most Permian natural gas production is associated with crude oil production. Natural gas production in the region has

September 2026

been growing faster than crude oil production as natural gas-to-oil ratios increase. The Permian natural gas-to-oil ratio averaged nearly 4,200 cubic feet per barrel in 2025, 15% higher than in 2021. Additionally, pipeline capacity additions help support production growth through the forecast period. Energy Transfer's Hugh Brinson pipeline—which originates in the Permian—began interstate natural gas shipments in June, which is earlier than we had previously expected. The pipeline will ramp up flows through early 2027.

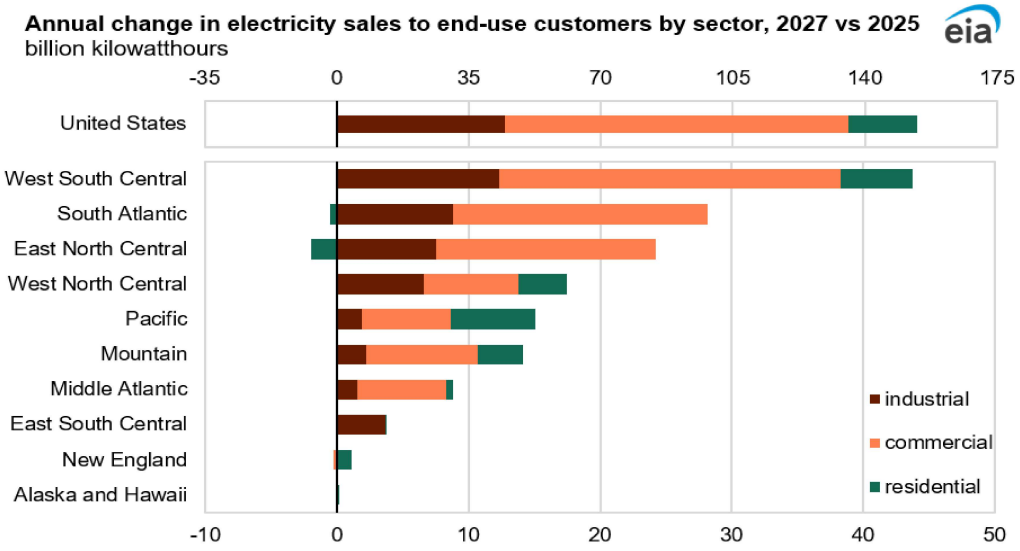
Haynesville production in our forecast increases by 1.4 Bcf/d in 2026 and by 1.3 Bcf/d in 2027, supported by forecast stable natural gas prices at Henry Hub, the region's proximity to Gulf Coast liquefied natural gas export terminals, and nearby industrial demand. Appalachian production increases by about 0.6 Bcf/d in 2026 and 0.3 Bcf/d in 2027.

Electricity, Coal, and Renewables

Electricity consumption

Electricity consumption reaches record levels in our forecast, driven by data center development and increased manufacturing activity in the commercial and industrial sectors. We expect electricity sales in the United States to total 4,135 billion kilowatthours (BkWh) in 2026, an increase of almost 2% over 2025. We expect an additional growth of nearly 2% in electricity sales in 2027, with total electricity consumption totaling 4,211 BkWh in 2027. We forecast that commercial sector electricity sales will increase by 3.3% in 2026 and 2.7% in 2027, accounting for 63% and 56% of the increase in electricity sales in those years. We forecast industrial sector electricity sales will rise 1.6% in 2026 and 2.6% in 2027, accounting for an additional 22% and 36% of increased electricity sales, respectively. Although Texas has paused the connection of new data centers to the grid to facilitate a regulatory audit of proposed data center projects, the West South Central region still accounts for the largest regional share of growth in total electricity sales, totaling nearly 20% of nationwide growth in 2026 and nearly 40% in 2027.

September 2026



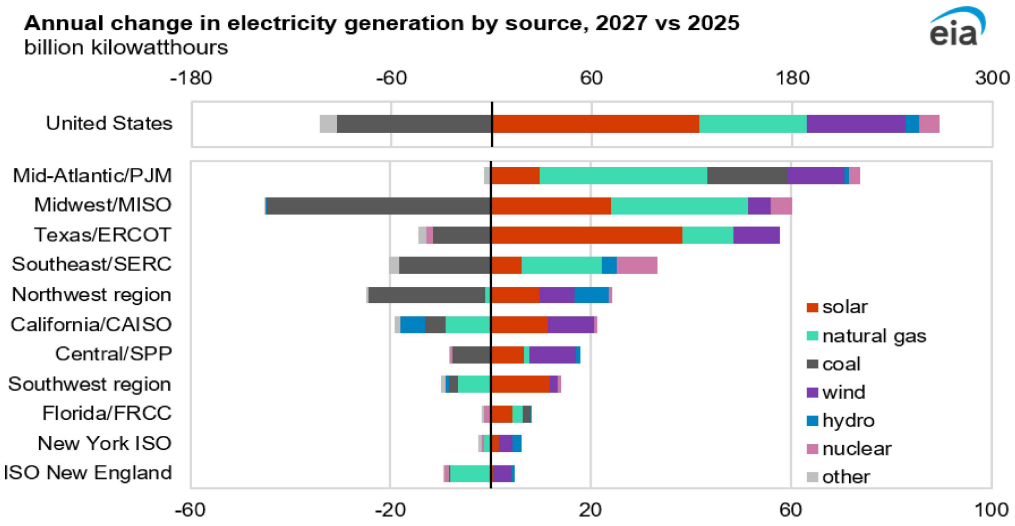
Data source: U.S. Energy Information Administration, *Short-Term Energy Outlook*, September 2026

Electricity generation

Electricity generation grows in line with electricity use in the forecast. With natural gas generation in the United States rising by 2% in 2026 and 1% in 2027, coal generation falls by 8% in 2026 and 6% in 2027. As wind and utility-scale solar capacity continues to be added to the grid, we expect solar generation to grow by 21% in 2026 and by 18% in 2027, while wind generation grows 7% in 2026 and 5% in 2027.

We expect the PJM interconnection to account for nearly 45% of the growth in total U.S. generation in our forecast, with natural gas generation driving the increase in 2026 and natural gas, coal, and wind generation driving the increase in 2027. Meanwhile, the growth in solar generation is concentrated in the parts of the grid managed by the Electric Reliability Council of Texas (ERCOT) and the Midcontinent Independent System Operator (MISO). In 2026, we expect added solar generation of 18 BkWh in ERCOT and 13 BkWh in MISO, followed by an additional 20 BkWh in ERCOT and 11 BkWh in MISO in 2027.

September 2026



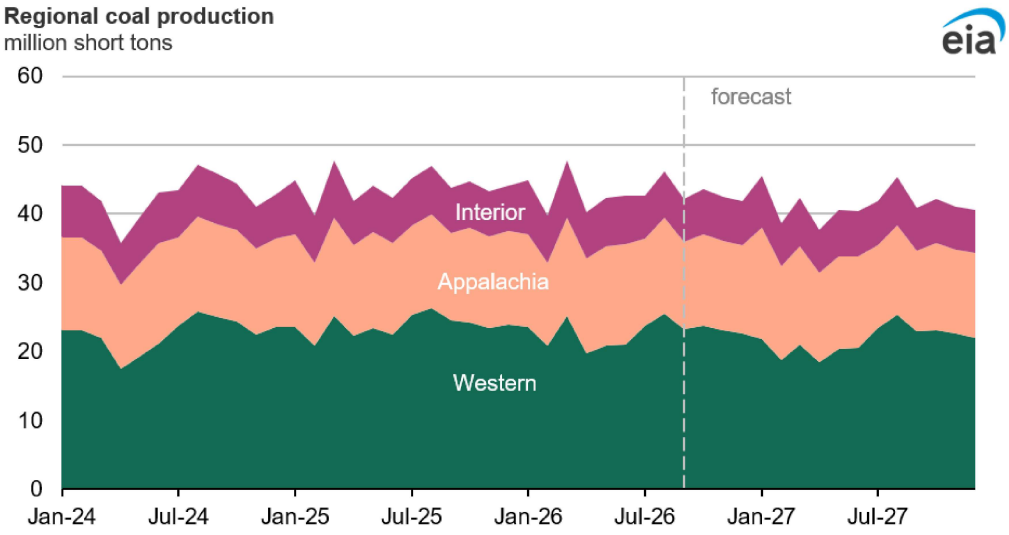
Data source: U.S. Energy Information Administration, *Short-Term Energy Outlook*, September 2026

Coal markets

Reduced demand for coal in the electric power sector leads to lower coal production in our forecast. We expect coal production to fall from 528 million short tons (MMst) in 2025 to 516 MMst in 2026 and 497 MMst in 2027. The decline is driven primarily by the Western region, which produces about half of total coal supply in the country. We expect production in the Western region to decline by about 4% in 2026 and another 5% in 2027, to a total of 260 MMst. Smaller changes are expected in the Appalachian region, where production in 2026 remains relatively flat before declining by about 2% in 2027. The Interior region also is expected to have similar production levels in 2026 as last year, before dropping by about 5% in 2027 to 79 MMst.

Although coal exports in our forecast increase compared with 2025, we forecast domestic demand for coal from the electric power sector will decline by 8% in 2026 and 6% in 2027, as natural gas and renewables generation in the Northwest and MISO regions increases.

September 2026



Data source: U.S. Energy Information Administration, *Short-Term Energy Outlook*, September 2026

Economy, CO_2, and Weather

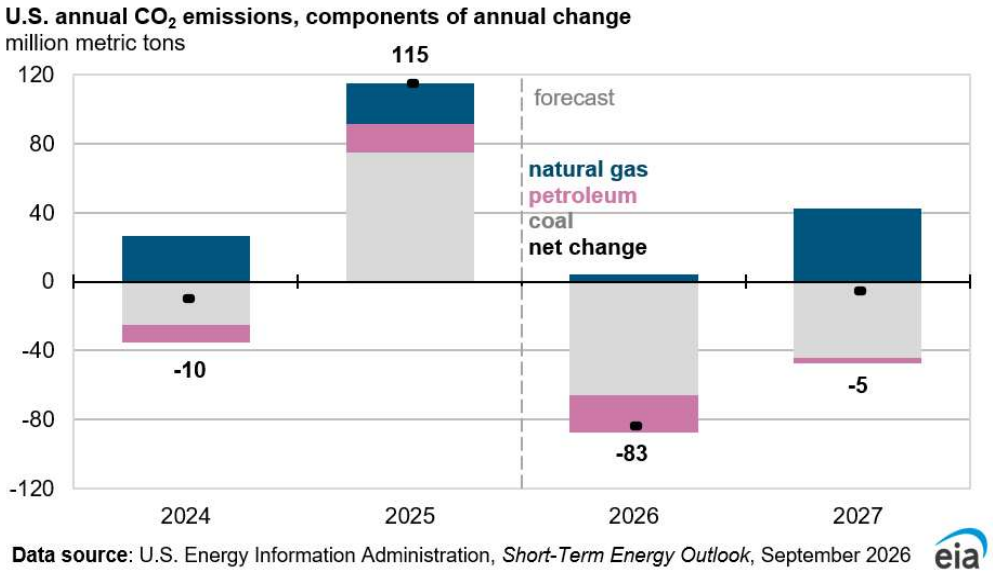
U.S. macroeconomics

To generate the macroeconomic assumptions in the *Short-Term Energy Outlook* (STEO), we input STEO energy price forecasts into S&P Global's Short-Term U.S. Macroeconomic Model to produce a conditional macroeconomic forecast. For more details on the macroeconomic model, see our documentation.

Emissions

We forecast U.S. energy-related carbon dioxide (CO_2) emissions to decrease by 1.7% in 2026 relative to 2025 and to decrease by 0.1% in 2027. In 2026, decreases in CO_2 emissions are due primarily to expected declines in coal consumption and, to a lesser extent, declines in consumption of various petroleum products, most notably motor gasoline and distillate fuel oil. Declines in both coal-related and petroleum-related emissions are expected to continue in 2027 but are offset by rising natural gas-related emissions, largely in the form of natural gas-fired electricity generation, resulting in a net decrease in total CO_2 emissions.

September 2026



Weather

We expect average temperatures in the final weeks of summer (June—September) to slightly offset warmer-than-average temperatures in July and August. Based on our current forecasts and data from the National Oceanic and Atmospheric Administration, we expect the United States to average 208 cooling degree days (CDDs) in September, 3% more CDDs than September 2025 about the same as the 10-year monthly average. Overall, our forecast assumes 2026 will be warmer than average, supported by warmer weather this summer—5% more CDDs than the 10-year summer average—and 5% fewer heating degree days in the first quarter of 2026 than the 10-year quarterly average.

CNG

Docket No. 99-10-01

Directive No. 4 Attachment

Weather Forecasting Information

Connecticut Natural Gas Corporation

Docket No. 26-10-01

Directive No. 4 Attachment

The Connecticut weather forecast, including all assumptions used in the filing, and for the next filing period.

For the longer term, (greater than five gas days), the Company uses various sources of publicly available information. An example of such a report would be the U.S. Department of Commerce, The National Oceanic and Atmospheric Administration (NOAA), 6-to-10-day, 30 day, 30 to 90 day, or multi-season forecast.

In the short term, (current gas day and the next five gas days), the Company receives a weather forecast from Atmospheric G2 This information is received four times a day and is used to estimate the system send out requirements.

As of September 17, 2026, based on information from the U.S. Department of Commerce, The National Oceanic and Atmospheric Administration (NOAA) the following probability (Percent Chance) temperature predictions are made:

October 2026 through December 2026: indicated the probability of experiencing leaning above normal temperatures. (Likely Above 40%-50%).

November 2026 through January 2027: indicated the probability of experiencing leaning above normal temperatures. (Leaning Above 40%-50%).

December 2026 through February 2027: indicated the probability of experiencing leaning above normal temperatures. (Leaning Above 40%-50%).

January 2027 through March 2027: indicated the probability of experiencing likely above normal temperatures. (Likely Above 50%-70%).

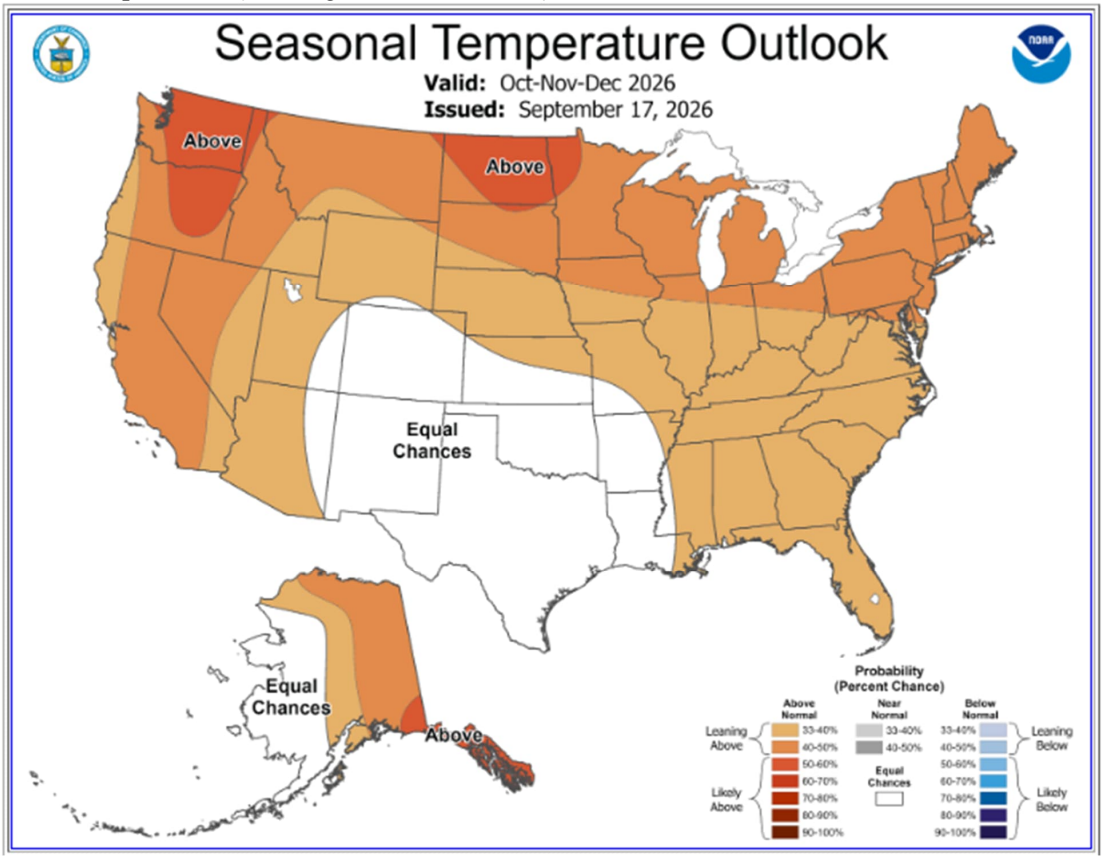
Connecticut Natural Gas Corporation
Docket No. 26-10-01

Directive No. 4 Attachment (cont'd)

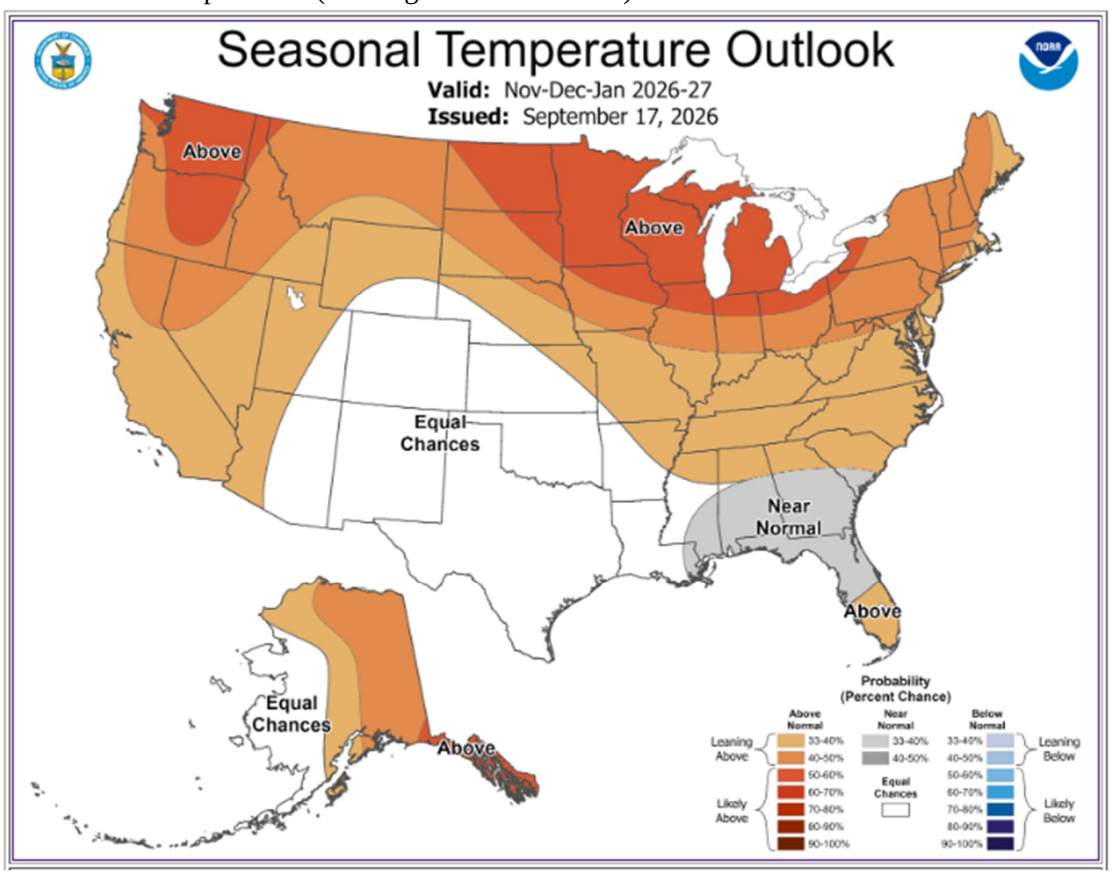
Finally, for planning and budgeting purposes, the Company uses the rolling thirty-year degree-day normal. For the period October 2025 through March 2026, the following degree-day information was used:

Month	Hartford		Greenwich	
	Monthly	Billing	Monthly	Billing
Oct 25	358	181	271	74
Nov 25	669	528	572	360
Dec 25	980	757	862	602
Jan 26	1,148	1,165	1,029	988
Feb 26	969	1,085	883	983
Mar 26	814	857	765	851

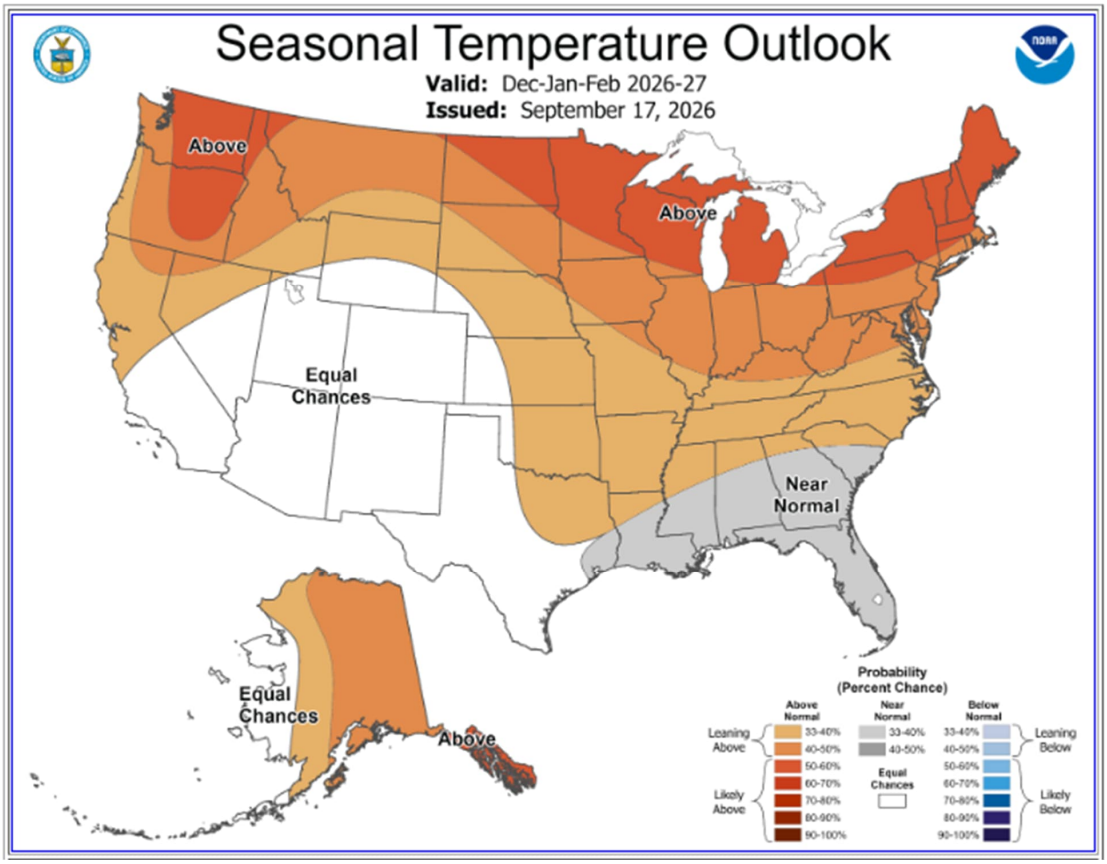
October 2026 through December 2026: indicated the probability of experiencing leaning above normal temperatures (Leaning Above 40%-50%).



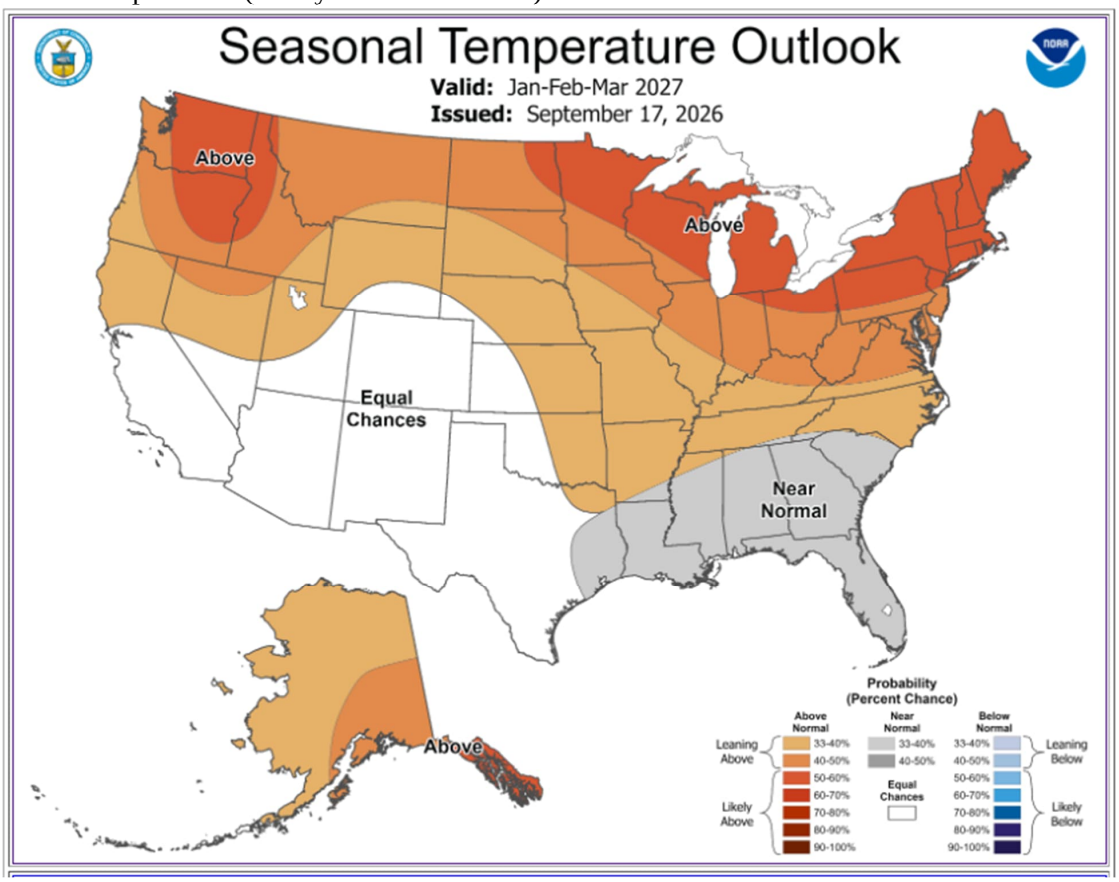
November 2026 through January 2027: indicated the probability of experiencing leaning above normal temperatures (Leaning Above 40%-50%).



December 2026 through February 2027: indicated the probability of experiencing leaning above normal temperatures (Leaning Above 40%-50%).



January 2027 through March 2027: indicated the probability of experiencing likely above normal temperatures (Likely Above 50%-70%).



Atmospheric G2
638 AM EDT TUE OCT 06 2026

Monday 05-Oct-26

	Hartford, CT		Bridgeport, CT	
TIME	TMP	WIND	TMP	WIND
10AM	57	N 0	62	SW 8
11AM	63	N 0	65	SW13
NOON	68	NW16	70	W13
1PM	70	W13	71	W13
2PM	69	W22	70	NW16
3PM	65	NW22	70	W15
4PM	65	W17	69	NW20
5PM	64	NW16	66	NW14
6PM	61	NW10	65	W10
7PM	58	NW13	61	W 8
8PM	56	NW14	59	W 7
9PM	54	NW11	57	W 7
10PM	52	NW11	55	NW 6
11PM	53	W17	53	W 9
MIDN	51	W11	53	NW 7
1AM	49	W 8	51	NW 5
2AM	49	W10	49	W 5
3AM	47	W11	47	NW 7
4AM	46	W11	46	NW 7
5AM	44	N 0	46	NW 6
6AM	43	NW 9	45	NW 5
7AM	42	NW 8	44	NW 6
8AM	44	NW10	47	NW 7
9AM	47	NW12	49	NW 9
10AM	50	NW12	52	NW12
AVG	DD	EHDD	AVG	DD	EHDD
55	10	11	57	8	9
MAX	MIN	AV WND	MAX	MIN	AV WND
70	42	11	71	44	9
TIME	TIME	CDD	TIME	TIME	CDD
1300	0700	0	1300	0700	0

Tuesday 06-Oct-26

	Hartford, CT		Bridgeport, CT	
TIME	TMP	WIND	TMP	WIND
10AM	50	NW12	52	NW12
11AM	53	NW11	54	NW12
NOON	55	NW12	56	NW12
1PM	57	NW12	58	NW11
2PM	59	NW12	59	NW11
3PM	59	NW13	60	NW10
4PM	59	NW12	61	NW10
5PM	58	NW11	60	NW 9
6PM	55	NW 8	59	NW 7
7PM	52	NW 6	57	NW 6
8PM	49	NW 4	54	NW 5
9PM	47	W 4	53	NW 5
10PM	46	W 4	51	NW 4
11PM	44	W 4	50	NW 4
MIDN	42	W 4	49	NW 4
1AM	41	W 2	47	NW 3
2AM	40	W 2	46	NW 4
3AM	38	SW 2	46	NW 3
4AM	38	S 2	45	NW 2
5AM	37	SW 1	44	NW 2
6AM	36	SW 2	44	NW 1
7AM	36	S 2	43	NW 2
8AM	40	SW 2	47	NW 2
9AM	44	S 4	52	SE 3
10AM	51	S 6	56	S 6
AVG	DD	EHDD	AVG	DD	EHDD
47	18	19	52	13	14
MAX	MIN	AV WND	MAX	MIN	AV WND
59	36	6	61	43	6
TIME	TIME	CDD	TIME	TIME	CDD
1500	0700	0	1600	0700	0

LONG RANGE FORECAST									
	TEMPERATURES (F)				AVG WIND	AVG	DEG	EFF	CLG
	MAX	TIME	MIN	TIME	MPH	TMP	DAY	DD	DD
	===	====	===	====	===	===	===	===	===
Wednesday 07-Oct-26									
Hartford, CT	66	1600	51	1000	8	57	8	9	0
Bridgeport, CT	65	1500	56	1000	10	60	5	5	0
Pittsfield, MA	62	1500	49	1000	7	55	10	11	0
Greenfield, MA	64	1600	48	1000	7	55	10	11	0
	TEMPERATURES (F)				AVG WIND	AVG	DEG	EFF	CLG
	MAX	TIME	MIN	TIME	MPH	TMP	DAY	DD	DD
	===	====	===	====	===	===	===	===	===
Thursday 08-Oct-26									
Hartford, CT	74	1500	47	0700	7	59	6	6	0
Bridgeport, CT	73	1500	54	0600	8	63	2	3	0
Pittsfield, MA	66	1500	44	0700	6	54	11	11	0
Greenfield, MA	70	1500	45	0700	6	56	9	9	0
	TEMPERATURES (F)				AVG WIND	AVG	DEG	EFF	CLG
	MAX	TIME	MIN	TIME	MPH	TMP	DAY	DD	DD
	===	====	===	====	===	===	===	===	===
Friday 09-Oct-26									
Hartford, CT	67	1500	44	0500	7	54	11	11	0
Bridgeport, CT	68	1500	50	0500	8	58	7	7	0
Pittsfield, MA	59	1500	40	0700	6	49	16	17	0
Greenfield, MA	63	1500	40	0700	5	51	14	15	0
	TEMPERATURES (F)				AVG WIND	AVG	DEG	EFF	CLG
	MAX	TIME	MIN	TIME	MPH	TMP	DAY	DD	DD
	===	====	===	====	===	===	===	===	===
Saturday 10-Oct-26									
Hartford, CT	66	1500	48	0700	6	55	10	10	0
Bridgeport, CT	66	1500	55	0700	7	59	6	6	0
Pittsfield, MA	61	1500	47	0700	5	53	12	13	0
Greenfield, MA	63	1400	46	0700	5	53	12	13	0

CNG

Docket No. 99-10-01

Directive No. 5 Attachment

Typical Residential Heating Customer Bill

Connecticut Natural Gas Corporation
Docket No. 26-10-01

Docket No. 99-10-01
Directive No. 5 Attachment

Page 1 of 1

Typical Residential Heating Customer
Monthly Bill of 150 CCF

	September-25	October-25	November-25	December-25	January-26	February-26	March-26	April-26	May-26	June-26	July-26	August-26
Customer Charge	$ 18.00	$ 18.00	$ 18.00	$ 18.00	$ 18.00	$ 18.00	$ 18.00	$ 18.00	$ 18.00	$ 18.00	$ 18.00	$ 18.00
Delivery Charge-1st Block	$ 22.18	$ 22.18	$ 22.18	$ 22.18	$ 22.18	$ 22.18	$ 22.18	$ 22.18	$ 22.18	$ 22.18	$ 22.18	$ 22.18
Delivery Charge-Over 30 ccf	$ 39.68	$ 39.68	$ 39.68	$ 39.68	$ 39.68	$ 39.68	$ 39.68	$ 39.68	$ 39.68	$ 39.68	$ 39.68	$ 39.68
DIMP Charge	$ 6.84	$ 6.84	$ 6.84	$ 6.84	$ 6.84	$ 6.84	$ 6.84	$ 6.84	$ 4.41	$ 4.41	$ 4.41	$ 4.41
CAM Charge	$ 6.90	$ 6.90	$ 6.90	$ 6.90	$ 6.90	$ 6.90	$ 6.03	$ 6.03	$ 6.03	$ 6.03	$ 6.03	$ 6.03
Sales Services Charge	$ 7.10	$ 7.10	$ 7.10	$ 7.10	$ 7.10	$ 7.10	$ 7.10	$ 7.10	$ 7.10	$ 7.10	$ 7.10	$ 7.10
Decoupling Charge	$ 9.13	$ 9.13	$ 9.13	$ 9.13	$ 9.13	$ 9.13	$ 9.13	$ 2.65	$ 2.65	$ 2.65	$ 2.65	$ 2.65
SER Charge	$ 3.57	$ 3.57	$ 3.57	$ 3.57	$ 3.57	$ 3.57	$ 3.57	$ -	$ -	$ -	$ -	$ -
PGA Factor	$ 0.4588	$ 0.4676	$ 0.6440	$ 0.6804	$ 0.6591	$ 0.7011	$ 0.7324	$ 0.7061	$ 0.6026	$ 0.4985	$ 0.4985	$ 0.4985
PGA Charge	$ 68.82	$ 70.14	$ 96.60	$ 102.06	$ 98.87	$ 105.17	$ 109.86	$ 105.92	$ 90.39	$ 74.78	$ 74.78	$ 74.78
Total Bill:	$ 182.22	$ 183.54	$ 210.00	$ 215.46	$ 212.27	$ 218.57	$ 222.39	$ 208.40	$ 190.44	$ 174.83	$ 174.83	$ 174.83

CNG

Docket No. 99-10-01

Directive No. 6 Attachment

Least Cost Gas Strategy

Connecticut Natural Gas Corporation
Docket No. 26-10-01

Directive No. 6 Attachment

A discussion and evidence of the Company's strategy to obtain the least cost gas for firm ratepayers for storage use.

CNG's total storage position consists of 10 bcf of underground storage capacity and 1.1 bcf of LNG capacity which is filled with summer, off-peak gas which is typically lower priced. CNG's storage capacity equates to about 40% of total firm demand during the winter period of November through March, if fully withdrawn. There is no winter price increase exposure for the volumes of off-peak priced gas held in storage. From an overall portfolio perspective, this stored gas serves to buffer the weighted average cost of gas when wellhead prices spike as withdrawals can be increased. To the extent unusual market conditions result in winter prices lower than summer prices, some storage withdrawals can be reduced and displaced with flowing gas to lower the cost of gas.

The reasons why storage strategies reduce the cost of gas are; lower fixed capacity costs, lower commodity costs and lower system balancing costs coupled with high reliability and operational flexibility. The overall gas portfolio is more efficient, reliable, and lower cost because gas storage coupled with downstream pipeline firm transportation is well suited to the temperature sensitive demand served by the Company. Lower overall fixed capacity costs accrue due to the to a significant amount of lower cost shorter haul transportation from gas storage areas. The Company's LNG peaking facility allows for a reliable supply in lieu of more expensive interstate pipeline transportation.

Gas commodity prices are typically lower in the off-peak months as summer prices have been below subsequent winter prices most historical years and are expected to remain so per future seasonal price curves. Storing summer gas for withdrawal in the winter, when nationwide demand is higher, stabilizes and reduces the cost of gas over the long term. Summer gas in storage also is not affected by winter period price spikes that may occur in the gas market.

Storage, coupled with downstream pipeline firm transportation provides critical daily and intra-day operational flexibility to balance the gas distribution system for weather and demand deviations from forecast, and for contingencies. This occurs through daily and intra-day injection and withdrawal activity. During most of the winter the Company operates in an environment of almost constant pipeline restrictions and tight operational parameters and the flexibility of both gas storage and LNG peaking allow for lower balancing costs by allowing for variations to be met by reliably varying storage activity instead of more expensive flowing contract activity.

CNG

Docket No. 01-10-17

Order No. 2

Benefits of Secondary Market Activities

Connecticut Natural Gas Corporation
Docket No. 26-10-01

Question: **Order Number 2 of the Decision dated February 22, 2002 in Docket 01-10-17, states: "The Companies shall supplement their future semi-annual PGA filings to include an evaluation of the benefits to firm customers of the Companies' secondary market activities."**

Response: During the period of September 1, 2025 to August 31, 2026, the Company estimates that its Secondary Market Activities yielded estimated margins of approximately nine million dollars.

During the PGA period capacity services program (long haul capacity release, Rate STO and Rate PK) resulted in approximately one million dollars in PGA demand credits for firm customers. Providing these services decreases secondary market margins achievable by CNG.

Secondary Market in Context

In the natural gas industry, the "secondary market" for natural gas refers to capacity release and off-system sales activities which are performed using firm transportation capacity acquired in the "primary market" by LDCs. The "primary market" is the regulated market for firm transportation and priced based upon the pipeline's FERC regulated gas tariffs. The "primary market" is typically longer term in nature and makes the use of so-called primary receipt and delivery points, which are only subject to reduction by the pipeline under force majeure conditions. The "secondary market" is short term in nature and makes use of so-called secondary receipt and delivery points which are on an "as available" basis after all primary service requirements have been satisfied. Secondary market activities are opportunistic, if and when available, and can be risky from several standpoints, and the Company always participates in such markets only subject to firm customer reliability as the highest priority.

The Company's gas supply portfolio is comprised of primary capacity. To the extent on-system customer demand does not require all the primary capacity during a particular period, taking into account appropriate balancing and contingency needs, the Company may participate in the off-system sales (such as daily or intra-day) and capacity release markets after balancing all the considerations. These considerations include risk, intra-day change needs for weather and demand, supplier of last resort and marketer services and other operational issues and parameters both on-system and on the interstate pipelines. The capacity situation in the New England region coupled with a relatively higher level of interstate pipeline force majeure/unplanned events being experienced significantly impact optimization opportunities.

CNG

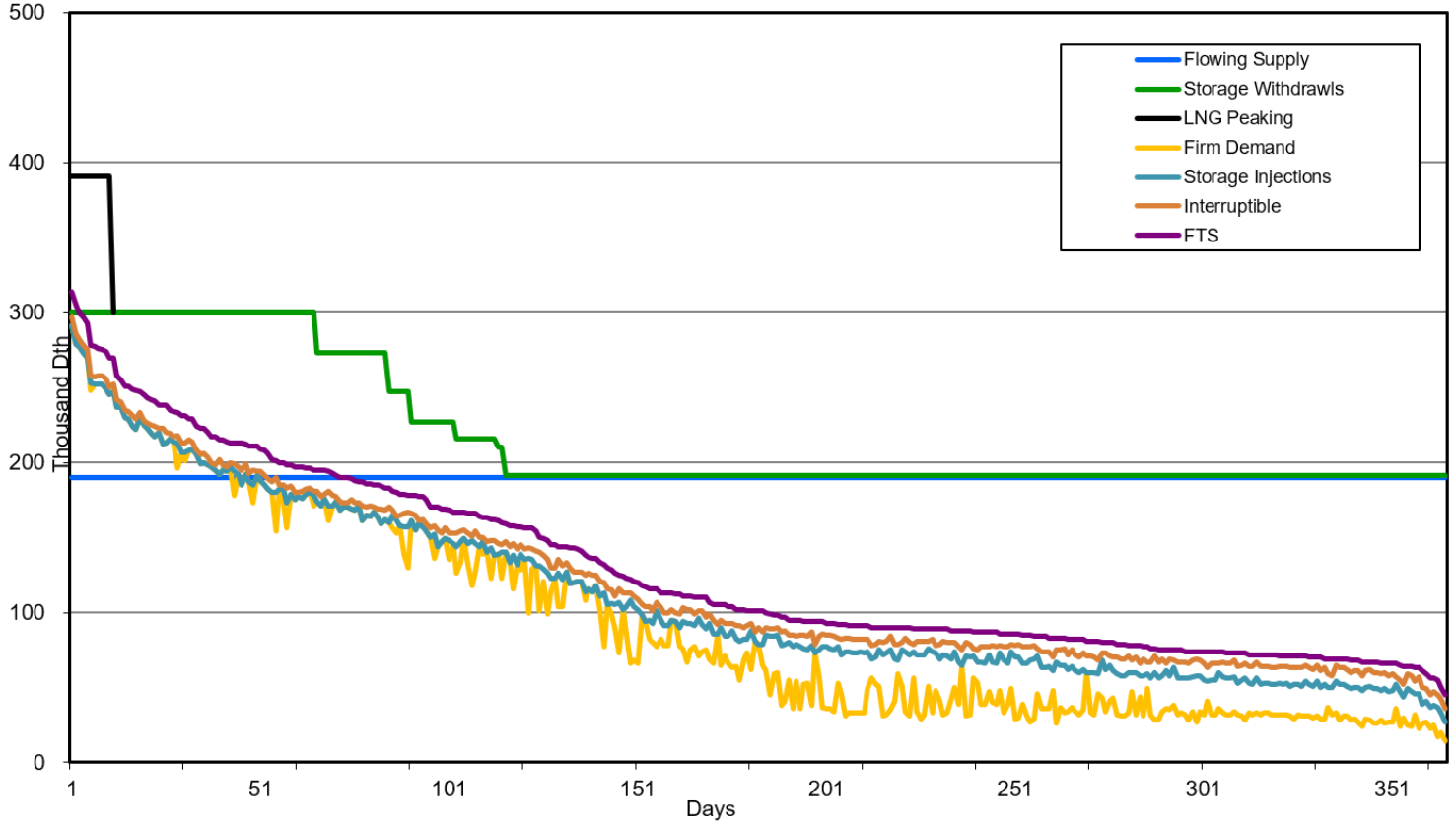
Docket No. 94-01-12

Order No. 5

Annual Load Duration Curve

Connecticut Natural Gas Corporation **Pursuant to Docket No. 94-01-12 Order No.5**
Docket No. 26-10-01

CNG Load Duration Curve
PGA Year Ending August 31, 2026



CNG

Docket No. 04-05-11

Order No. 1

Directives

Connecticut Natural Gas Corporation
Docket No. 26-10-01

In addition, in response to the final decision in Docket No. 04-05-11 Order No. 1, each LDC must submit the following items with every semi-annual PGA filing beginning with Docket No. 05-10-01:

1) Each LDC that uses LNG or any other peaking resource while interruptible and/or off-system customers are receiving gas on a daily basis shall provide a report that includes the information discussed in Section II.A. 1. Peaking Supplies.

   Response: See **Directive No. 1 Attachment** for LNG or any other peaking resource used while interruptible and/or off-system customers are receiving gas on a daily basis.

2) Each LDC choosing to make fixed price transactions with interruptible customers for any period of time shall submit documentation of these transactions as discussed in Section H.A.2. Fixed Price Interruptible Contracts.

   Response: There were no fixed price interruptible contracts during this PGA period.

3) Each LDC making off-system sales transactions outside of New England and New York shall provide detailed documentation on each transaction that includes quantities, duration, and pricing information as discussed in Section ILA.3. Off-System Sales.

   Response: During the PGA period, no such off-system sales were made by the Company outside of the New England/New York region.

4) Each LDC shall show how the cost of gas injected into storage compares to the commodity cost of pipeline gas on a monthly basis from November to March in a report as discussed in Section II.A.4. Storage Withdrawals.

   Response: See **Directive No. 4** Attachment for a monthly comparison of the cost of gas injected into storage versus the commodity cost of pipeline for the period November 2025 through March 2026.

CNG

Docket No. 04-05-11

Order No. 1

Directive No. 1 Attachment

Peaking Supplies

Connecticut Natural Gas Corporation
Docket No. 26-10-01

Docket 04-05-11 Order # 1
Directive No. 1 Attachment

Report Peaking Supplies
Daily peaking resources used while interruptible and/or off-system customers are receiving gas.

September 2025 to August 2026

Date	IS and OSS /e	Refill Cost/MMBtu /c	Peaking Cost $/MMBtu	Total Peaking Used/MMBtu	Notes	Margins/d
10/28/25	971	$5.47	$6.34	971	/a	$1.13
11/05/25	169	$5.59	$6.38	169	/a	$1.97
11/06/25	867	$5.59	$6.38	867	/a	$1.97
12/08/25	2,884	$5.13	$6.41	2,884	/a	$6.69
01/01/26	2,193	$4.81	$6.46	2,193	/b	$3.66
01/23/26	4,727	$4.81	$6.46	4,727	/b	$3.66
01/24/26	1,132	$4.81	$6.46	19,271	/b	$3.66
01/25/26	917	$4.81	$6.46	15,984	/b	$3.66
01/27/26	4,826	$4.81	$6.46	4,826	/b	$3.66
01/29/26	6,958	$4.81	$6.46	6,958	/b	$3.66
01/30/26	903	$4.81	$6.46	20,137	/b	$3.66
02/07/26	0	$5.18	$6.50	35,930	/b	$1.21
02/08/26	0	$5.18	$6.50	25,992	/b	$1.21
02/09/26	2,163	$5.18	$6.50	2,163	/b	$1.21
02/24/26	68	$5.18	$6.50	68	/a	$1.21
02/25/26	1,390	$5.18	$6.50	1,390	/a	$1.21

Notes
/a Peaking used for LNG testing.
/b Peaking used for for LDC peaking, operational considerations, weather change, pressure management
/c estd refill cost at the time of the decision
/d based upon average actual IS monthly margin.

Internal Use

CNG

Docket No. 04-05-11

Order No. 1

Directive No. 4 Attachment

Comparison of Cost of Gas

Storage vs. Pipeline

Connecticut Natural Gas Corporation
Docket No. 26-10-01

Docket No. 04-05-11 Order #1
Directive No. 4 Attachment

Comparison of cost of gas injected into storage to the commodity cost of pipeline gas on a monthly basis from November to March:

	Storage Inventory Cost $/MMBTU**
Underground storages (all- average)	$2.80

Winter Month	Most Expensive Pipeline Costs for Each Winter Month /b $/MMBtu
Nov-25	$3.02
Dec-25	$9.82
Jan-26	$10.11
Feb-26	$12.91
Mar-26	$3.23

**Excludes small additional charges for pipeline transport from storage field to city gate. Cost as of 11/1/2025. WACOG applies to winter 2025/2026.
/b Most expensive of monthly purchased supplies.

CNG

Docket No. 08-12-06

Order Nos. 34 & 43

Non-Firm Margins

CONNECTICUT NATURAL GAS CORPORATION
DOCKET NO. 26-10-01

ORDER NO. 29 OF DOCKET NO. 08-12-06
MARGIN SHARING MECHANISM

NON-FIRM MARGIN SOURCES	Sep-25	Oct-25	Nov-25	Dec-25	Jan-26	Feb-26	Mar-26	Apr-26	May-26	Jun-26	Jul-26	Aug-26	TOTAL
INTERR & TS & ITS & NGV MARGIN	$ 321,326.89	$ 311,099.34	$ 410,711.48	$ 646,499.92	$ 609,038.05	$ 237,161.23	$ 688,566.54	$ 716,781.20	$ 365,215.62	$ 335,286.13	$ 416,786.97	$ 393,089.98	$ 5,451,563.35
OFF SYSTEM - SALES & TRANSPORTATION	$ -	$ -	$ 280,363.58	$ 1,338,797.89	$ 3,330,414.30	$ 10,450.21	$ 218,378.85	$ 2,233.67	$ -	$ -	$ 165,625.71	$ 27,467.26	$ 5,373,731.47
VOLUNTARY CAPACITY RELEASE / AMA	$ 346,524.84	$ 346,524.84	$ 399,775.42	$ 399,775.42	$ 399,775.42	$ 399,775.42	$ 399,775.42	$ 399,775.42	$ 399,775.42	$ 399,775.42	$ 399,775.42	$ 399,775.42	$ 4,690,803.88
TOTAL NON-FIRM MARGIN - MONTHLY	$ 667,851.73	$ 657,624.18	$ 1,090,850.48	$ 2,385,073.23	$ 4,339,227.77	$ 647,386.86	$ 1,306,720.81	$ 1,118,790.29	$ 764,991.04	$ 735,061.55	$ 982,188.10	$ 820,332.66	$ 15,516,098.70
NON FIRM MARGIN SHARING													
MONTHLY MARGIN	$ 667,851.73	$ 657,624.18	$ 1,090,850.48	$ 2,385,073.23	$ 4,339,227.77	$ 647,386.86	$ 1,306,720.81	$ 1,118,790.29	$ 764,991.04	$ 735,061.55	$ 982,188.10	$ 820,332.66	$ 15,516,098.70
MARGIN TO FIRM CUSTOMERS THROUGH PGA[1]	$ 667,851.73	$ 657,624.18	$ 1,090,850.48	$ 2,385,073.23	$ 4,339,227.77	$ 647,386.86	$ 1,306,720.81	$ 1,118,790.29	$ 764,991.04	$ 735,061.55	$ 982,188.10	$ 820,332.66	$ 15,516,098.70
RETURN ACCUMULATED NFM FROM RATE BASE TO PGA[2]	$ 126,006.92	$ 151,649.18	$ 290,137.51	$ 497,855.62	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,065,649.23

[1] Per Docket No. 23-11-02 - 2023 CNG Rate Case Final Decision, effective December 2024, 100% NFM to be returned to customers through the PGA
[2] Per Docket No. 23-11-02 - 2023 CNG Rate Case Final Decision, effective December 2024, the 2024 NFM portion to Rate Base is to be returned to customers through the PGA throughout 2025.