PUBLIC STAFF OF THE
NORTH CAROLINA
UTILITIES COMMISSION

August 24, 2022

VIA ELECTRONIC SUBMISSION ONLY

Ms. A. Shonta Dunston, Chief Clerk
North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, North Carolina 27699-4300

Re: Docket No. E-2, Sub 1292 – Application of Duke Energy Progress, LLC, Pursuant to N.C. Gen. Stat. 62-133.2 and Commission Rule R8-55 Relating to Fuel and Fuel-Related Charge Adjustments for Electric Utilities

Dear Ms. Dunston:

I hope this finds you doing well. In connection with the above-referenced docket, I transmit herewith for filing on behalf of the Public Staff the redacted public version of the Direct Testimony of John R. Hinton, Director of the Economic Research Division.

By copy of this letter, I am serving same on all parties of record by electronic delivery.

A confidential and unredacted version of same will be filed under separate cover and notice is hereby given that both that cover and the unredacted version will be served only on those attorneys identified as representing Duke Energy Progress, LLC (DEP) in the June 14, 2022 filing, as follows:

jack.jirak@duke-energy.com
ladawn.toon@duke-energy.com
dallen@theallenlawoffices.com

If any other party is permitted to review the unredacted version, they can contact either DEP or the undersigned regarding same.

Thank you for your attention. Please let me know if you would like additional information or to discuss this matter further.

With kind regards,

/s/ William Freeman, by electronic filing
William S. F. Freeman
William E. H. Creech
Staff Attorneys

Attachment as described

cc via email w/ attachment:
jack.jirak@duke-energy.com
gthompson@selcnc.org
Kendrick.Fentress@duke-energy.com
mmagarira@selcnc.org
bbreitschwerdt@mcguirewoods.com
bkaylor@rwkaylorlaw.com
ccress@bdixon.com
cshauer@brookspierce.com
mtrathen@brookspierce.com
ladawn.toon@duke-energy.com
dallen@theallenlawoffices.com

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1292

In the Matter of		
Application by Duke Energy Progress,	)	TESTIMONY OF
LLC, Pursuant to N.C.G.S. § 62-133.2	)	JOHN R. HINTON
and Commission Rule R8-55 Relating to	)	PUBLIC STAFF –
Fuel and Fuel-Related Charge	)	NORTH CAROLINA
Adjustments for Electric Utilities	)	UTILITIES COMMISSION

AUGUST 24, 2022

Q. PLEASE STATE YOUR NAME, POSITION, AND BUSINESS ADDRESS FOR THE RECORD.

A. My name is John R. Hinton, and my business address is 430 North Salisbury Street, Raleigh, North Carolina. I am the director of the Economic Research Division of the Public Staff. My qualifications and experience are provided in Appendix A.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to present my analyses and recommendations to the North Carolina Utilities Commission regarding Duke Energy Progress' (DEP or the Company) fuel hedging program. Hedging's costs or benefits flow to consumers through DEP Fuel Riders since fuel costs are generally a pass-through in ratemaking. My primary focus is on the DEP hedging program for natural gas. I address some of the economic benefits and costs of DEP's financial hedging program as described in its Risk Management Plans as well as reasons why DEP and energy companies have hedging programs. I also address the historical impacts of the Company's hedging programs on consumers.

Q. WHAT IS HEDGING AND WHY DOES THE COMPANY HAVE A HEDGING PROGRAM?

A. Energy companies, like the operating electric utilities within Duke Energy Corporation, have hedging programs to protect them – and therefore ultimately their customers – from fuel price volatility in the market. Volatility stems from the risks of the unknown future causing unforeseen substantial or frequent changes in prices and can unexpectedly happen at any time (witness the current conflict between Russia and Ukraine, unforeseen weather events, economic changes, and the recent global energy crisis to name a few). Thus it is difficult to accurately predict where (for example) natural gas prices will be in future months or years.

Hedging is a risk management strategy that mitigates the risks associated with changes in the price of a given asset. Hedging accomplishes the goal of reducing price volatility by locking-in the future price to be paid ahead of time rather than subjecting future fuel purchases to the day-to-day pricing changes that can occur in the marketplace. One common way to understand financial hedging is to think of it as a form of insurance that protects against future price changes and volatility.

Reducing volatility via hedging allows energy companies to maintain a clearer and more predictable future price. With the correct hedging program, energy companies will be able to minimize price changes and shocks to residential, commercial, and industrial customers.

Q. PLEASE DESCRIBE VOLATILITY AND HOW IT IS MEASURED.

A. Price volatility can be measured by looking to the amount of variability between the actual price and the average price over a given time. Often it is measured by the percent changes in day-to-day prices. The averages and changes are expressed via calculations of standard deviations from the norm.

The level of prices does not determine price volatility, but rather the degree of price variation. A large price movement when prices are high (for example a $1 movement with prices around $100) may not equate to the same volatility level as a smaller price movement (for example a $1 movement with prices around $10). In the second example, the $1 movement when the price is around $10 will be more volatile because the percentage change is higher.

Natural gas price volatility can be measured by taking the standard deviation of the historical standard deviation of changes in the prices over specific time periods of one year and longer. Another method of determining volatility is to examine the market prices of traded options. These forward-looking prices impliedly reflect implied assumptions on expected volatility. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

Q. DO HEDGING PROGRAMS HAVE COSTS?

A. Yes. First, utilities incur the cost of running the hedging program in terms of labor and related costs dedicated to implementing the program and the transaction costs of hedges. Often, these costs are relatively small when looking at the total net costs.

Second, utilities incur the net costs or savings with hedges, sometimes referred to as opportunity costs. With the purchase and sale of various hedging instruments relative to the market prices, there are losses when the market price is below the utility's hedged price. Alternatively, benefits occur when the market price is above the utility's hedged price. The accounting profession addressed hedging and derivatives in FASB Topic 815[1], where the cost of hedges is based on the difference in the hedge price of natural gas as compared to the current spot price of natural gas.

[1] Financial Accounting Standards Board, Derivatives and Hedging (Topic 815), August 28, 2017.

A clear benefit of hedging is stabilizing fuel prices and preventing future volatility in consumer prices. The appropriate level of hedge protection is, in part, a function of consumers' aversion to volatile electricity bills which is difficult to ascertain. However, at some point the benefit of stable fuel prices is outweighed by the hedge costs.

Q. DESCRIBE DEP'S HEDGING POLICY.

A. The two main commodity assets that DEP hedges for is coal and natural gas. Given there is a limited market of future contracts with coal, DEP's hedges are limited to physical procurement generally conducted with staggered contracts over several years.

DEP's natural gas hedge program uses **[BEGIN CONFIDENTIAL]** [redacted]

[redacted] **[END CONFIDENTIAL]**.

DEP believes having staggered contract terms represents a balanced natural gas fuel price risk management approach that limits customers exposure to actual market prices and mitigates natural gas price volatility in uncertain fuel markets. Furthermore, the Company maintains that its hedging program does not involve speculation.[2] DEP's internal hedge policy with respect to the lengths of the contracts is shown in the Table below:

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

[2] This was addressed in the Commission's Order on Hedging for the commodity cost with local natural gas companies on February 26, 2002 in Docket G-100, Sub 84.

Q. WHAT IS A FINANCIAL HEDGE AND WHAT INSTRUMENTS DOES DEP USE FOR NATURAL GAS FINANCIAL HEDGES?

A. DEP uses a "financial hedge" within its hedging program for natural gas. A financial hedge is the action of managing price risk by using financial derivatives to offset price movement of the physical asset (in this case, natural gas). Unlike a physical hedge, a financial hedge only protects against price swings – procurement of the assets is still needed.

[BEGIN CONFIDENTIAL] [redacted] **[END CONFIDENTIAL]**. Fixed Price Swaps "fix" (or lock in) the energy cost. A Fixed Price Swap is an agreement (over a specified period) where two sides of a deal select a fixed price for an asset instead of the market price – that is, the parties "swap" the floating market price for their agreed-upon fixed price. If the market price of the commodity ends up being lower than the fixed hedge price during the specified period, the utility (as the fixed price payer) still pays the fixed price on the contract and incurs a loss. Conversely, if the market price is higher, the utility incurs a benefit.

Q. WHAT MATERIALS DID YOU REVIEW AND RELY ON FOR THIS TESTIMONY?

A. In conducting my investigation, I reviewed nine DEP annual[3] fuel rider dockets, DEP's responses to Data Requests, monthly hedge reports from April 2012 to March 2022, and testimony within the referenced dockets. I reviewed DEP's hedging reports for 2008 through 2011 that showed similar net costs to that of 2012 through 2017; however, my analysis did not focus on those years.

Q. WHAT ARE THE RESULTS OF YOUR INVESTIGATION REGARDING DUKE'S HEDGING PROGRAM DURING THE TEST YEAR?

A. During the 2021 – 2022 test year, DEP hedged approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** of its actual natural gas fuel burn. The DEP financial hedging program for natural gas has reduced the cost of purchasing natural gas by $122.6 million.

[3] Docket No. E-2, Subs 1292, 1272, 1250, 1204, 1173, 1146, 1069, 1045, and 1031.

This translates to a savings of $1.90 per month (or $22.82 annually) for the typical 1,000 kWh per month residential customer.

My analysis indicates that DEP's hedging programs are reasonable. The management of the hedging program has worked to stabilize natural gas price swings. In this proceeding, the total DEP net benefit on a system level is $122,687,180 of which $75,452,616 is allocated to North Carolina. These benefits are significant when compared to DEP's total commodity cost of natural gas of $948,703,226.

Q. HOW DO THE NET SAVINGS FOR THE 2021-2022 TEST YEAR COMPARE WITH THE NET SAVINGS AND COSTS OF PRIOR FUEL PROCEEDINGS?

A. The $122.6 million net savings reported in this proceeding is the largest hedging consumer benefit DEP has ever posted. As previously noted, in the present proceeding DEP's hedging program has favorably reduced the annual typical consumer bill by $22.82. However, DEP's hedging has not always been so beneficial. For example, in 2012 and 2015 DEP's hedging had the opposite impact and increased the typical annual consumer bill by more than $22.82.

Over time, one could expect within any given year that hedging can result in an overall net savings benefit or net cost loss to consumers;

however, over several years it is reasonable to expect the savings and costs to largely offset one another. Nevertheless, even with this recent large benefit, DEP's overall hedging program over the recent years has reflected more net costs than savings. The following table and chart show DEP's historical record of net savings and net cost loss:

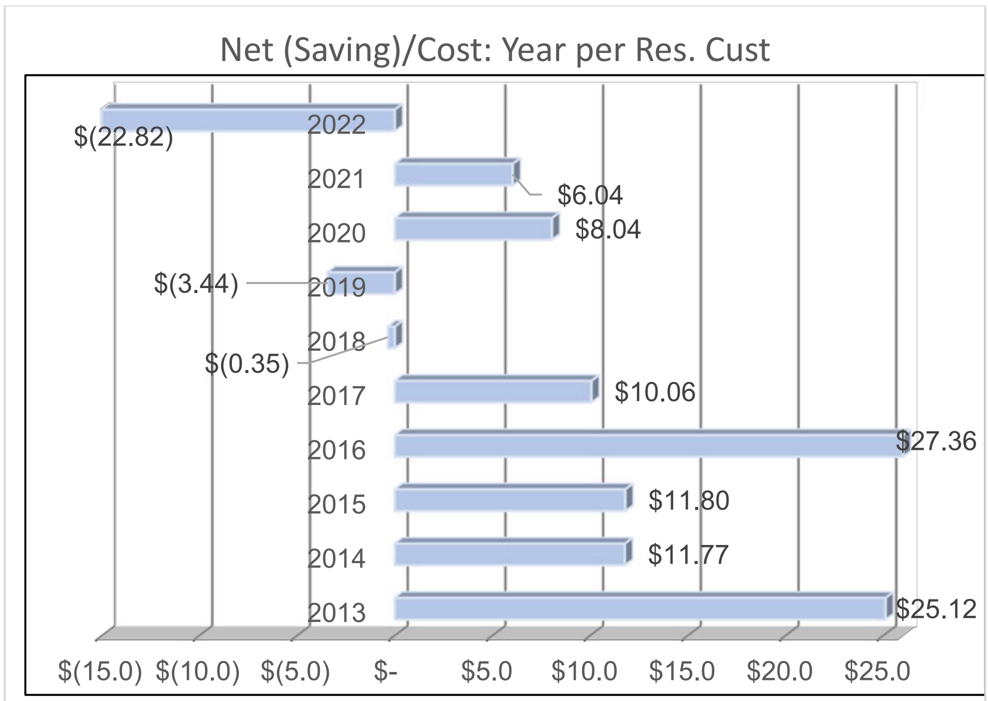
[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

It is also helpful to review the impact of DEP's hedging on the typical consumer's annual bill. While the annual net beneficial savings of

$22.82 per residential customer in this instant proceeding is the highest to date, the following table reveals larger net costs per customer of $27.36 in 2015 and $25.12 in 2012. Following is a table of the net savings and costs calculated on a per residential customer basis.



Q. WHAT ARE THE FACTORS CONTRIBUTING TO DEP'S COSTS OF ITS HISTORICAL HEDGING PROGRAM?

A. DEP's most significant net costs occurred in the years 2012 – 2017. During this period, many of these hedging contracts with large net costs were entered into **[BEGIN CONFIDENTIAL]** [redacted] **[END**

CONFIDENTIAL] years prior to the effective date. At the same time, there were unexpected decreases in natural gas prices. Therefore, hedged, or future natural gas prices were significantly higher than the actual market prices.

Another factor is the hedge horizon, meaning the length of time between the trade date and the effective date of the contract. The historical record has shown relatively large net costs with hedge contracts with horizons longer than **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. This is bolstered by the fact that during 2012 and the several adjoining years, Dominion Energy North Carolina utilized one-year hedges for natural gas.[4] Dominion's historical hedging program resulted in significantly lower net costs. Dominion's past

[4] *See, e.g.*, E-22 Sub 526, Testimony of Gregory A. Workman, pg. 7, filed August 19, 2015.

focus on one-year 1hedging prompted me to focus on the net cost and net savings with respect to the hedge horizon. Further, Dominion still utilizes a near-term price hedging strategy. Dominion testified it used “a price hedging program under which [Dominion] price hedges commodities needed for power generation using a range of volume targets, which gradually decrease over a three-year period.”[5]

Q. DO YOU QUESTION DEP’S ABILITY TO GAUGE THE GAS MARKET DURING THESE YEARS OF SIGNIFICANTLY LARGE NET COSTS?

A. No. During the 2008 through 2017 period industry participants were somewhat surprised by the continued decline in natural gas prices as shale gas came into the market. Attached is the Annual Energy Outlook (AEO) Retrospective Review provided by the U.S. Energy Information Administration (EIA) for forecasted natural gas prices in 2008-2013 for 2012-2017. The AEO Retrospective Review compares recent history with the reference case projections versus actual. The vast majority of AEO’s forecasted natural gas prices in 2008-2013 predicted higher future prices as compared to the actual prices as shown in Table 2 of Public Staff Hinton Exhibit I.

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[5] E-22, Sub 605, Testimony of Dale E. Hinson, pg. 3, lines 8-10, filed August 10, 2021.

Looking at DEP's hedging data for the year 2012, we see the highest costs occurring on deals executed in 2008 for the hedge year 2012. A clear reason for these high costs are the excessively high price predictions that are shown in Table 1 and Table 2 of my Exhibit I. In particular, the AEO forecast published in 2008 for 2012 was overestimated by 110%. See the below table for the analysis of DEP average hedge prices versus Henry Hub average monthly spot prices for the years 2012-2017.

[BEGIN CONFIDENTIAL]

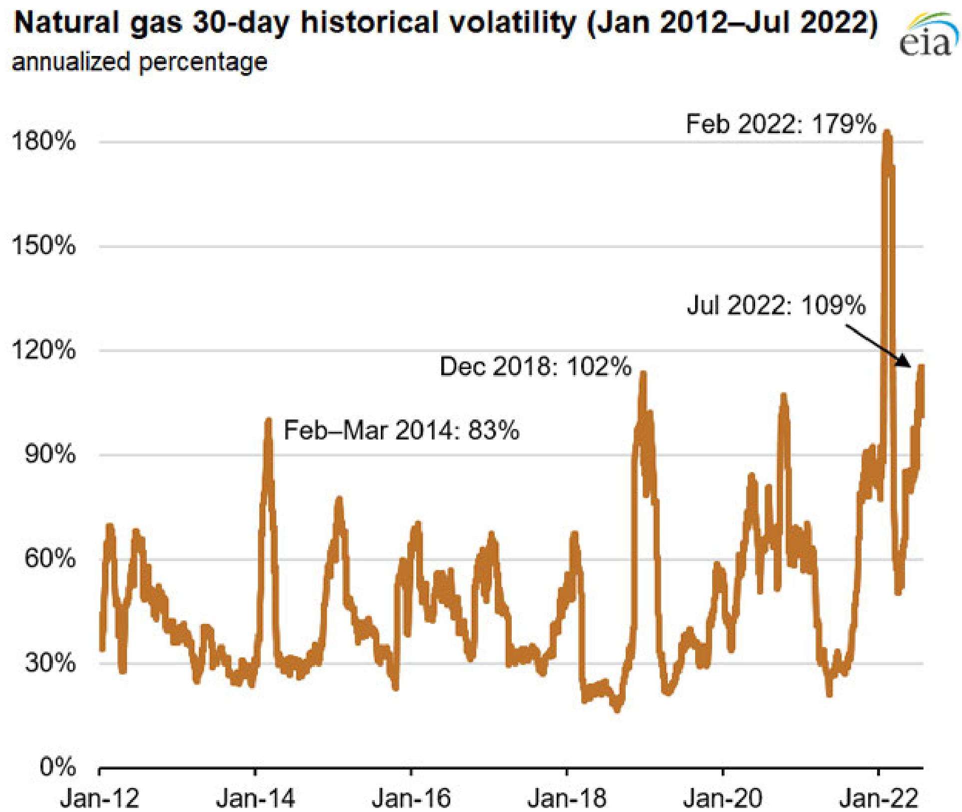
[redacted]

[END CONFIDENTIAL]

Q. IS THERE ANY EVIDENCE THAT THE MARKET VOLATILITY HAS CHANGED?

A. Yes. As previously noted, natural gas price volatility has significantly increased over the last 12 months as illustrated in the below graph from a report by the EIA. Prior to recent events, natural gas volatility was reasonably explained in an article from the June 2013 Wall Street Journal, "Volatility Evaporates in Natural-Gas Market" (Hinton Exhibit 2). That article describes how price volatility collapsed in the natural gas market with the development of shale gas which added additional sources of gas supply.

The EIA provides a current assessment of the volatility of Henry Hub future natural gas prices. The volatility reached a peak of 179% in February 2022 and 109% for July 2022 as compared to a recent historical average of 48% for 2017 through 2021. The complete EIA report that contains the following graph is shown in Hinton Exhibit 3.



Source: EIA, Natural Gas Weekly Update, August 11, 2022.

The recent increases in volatility support the use of hedges to avoid having to purchase gas at relatively higher prices. This increased volatility may prompt DEP to increase its hedge volumes which may reduce its exposure to relatively high gas prices. However, the above graph of increased volatility does not necessarily address the appropriate term structure of the hedges. **[BEGIN CONFIDENTIAL]** [redacted]

[redacted]

[redacted]

[END CONFIDENTIAL]

Q. DO YOU HAVE ANY RECOMMENDATIONS ON DEP'S HEDGING POLICY?

A. Yes, I recommend that DEP utilize a short-term hedging policy with one to three years lead time from the trade date and the effective date. If DEP decides to hedge beyond three years, I recommend that it stay on the lower side of the percentage band. Furthermore, this recommendation is consistent with my previous testimony filed in

DEP's fuel proceedings in Docket No. E-2, Subs 1001, 1018, and 1031.

I support DEP's position that it cannot predict future prices and its hedging program does not involve speculation. However, I contend that longer term deals entail an added degree of term risk where the expected benefits of stable prices are outweighed by the potential costs. DEP's forward volatility curves indicate that the expected volatility is drastically lower beyond future year three relative to one or two years. Even though long-term hedges entered into in 2017 and 2018 are currently producing net savings and reducing the cost of natural gas, I urge caution regarding entering into longer term deals greater than three years which have historically added costs to DEP's hedging program.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

QUALIFICATIONS AND EXPERIENCE

JOHN R. HINTON

I received a Bachelor of Science degree in Economics from the University of North Carolina at Wilmington in 1980 and a Master of Economics degree from North Carolina State University in 1983. I joined the Public Staff in May of 1985. I filed testimony on the long-range electrical forecast in Docket No. E-100, Sub 50. In 1986, 1989, and 1992, I developed the long-range forecasts of peak demand for electricity in North Carolina. I filed testimony on electricity weather normalization in Docket Nos. E-7, Sub 620, E-2, Sub 833, and E-7, Sub 989. I filed testimony on customer growth and the level of funding for nuclear decommissioning costs in Docket No. E-2, Sub 1023. I filed testimony on the level of funding for nuclear decommissioning costs in Docket Nos. E-7, Sub 1026 and E-7, Sub 1146. I have filed testimony on the Integrated Resource Plans (IRPs) filed in Docket No. E-100, Subs 114 and 125, and I have reviewed numerous peak demand and energy sales forecasts and the resource expansion plans filed in electric utilities' annual IRPs and IRP updates.

I have been the lead analyst for the Public Staff in numerous avoided cost proceedings, filing testimony in Docket No. E-100, Subs 106, 136, 140, 148, and Sub 158. I have filed a Statement of Position in the arbitration case involving EPCOR and Progress Energy Carolinas in Docket No. E-2, Sub 966. I have filed testimony in avoided cost related to the cost recovery of energy efficiency programs and demand side management programs in Dockets Nos. E-7, Sub 1032, E-7, Sub 1130, E-2, Sub 1145, and E-2, Sub 1174.

I have filed testimony on the issuance of certificates of public convenience and necessity (CPCN) in Docket Nos. E-2, Sub 669, SP-132, Sub 0, E-7, Sub 790, E-7, Sub 791, and E-7, Sub 1134.

I filed testimony on the merger of Dominion Energy, Inc. and SCANA Corp. in Docket Nos. E-22, Sub 551, and G-5, Sub 585.

I have filed testimony on the issue of fair rate of return in Docket Nos. E-22, Subs 333 412, and 532; P-26, Sub 93; P-12, Sub 89; G-21, Sub 293;P-31, Sub 125; P-100, Sub 133b; P-100, Sub 133d (1997 and 2002); G-21, Sub 442; G-5, Subs 327, 386; and 632; G-9, Subs 351, 382, and 722, W-778, Sub 31; W-218, Subs 319, 497, 526; W-354, Sub 360, 364, 384 and in several smaller water utility rate cases. I have filed testimony on financial metrics and the risk of a credit rating downgrade in Docket No. E-7, Sub 1146.

I have filed testimony on the hedging of natural gas prices in Docket No. E-2, Subs 1001, 1018, and 1031. I have filed testimony on the expansion of natural gas in Docket No. G-5, Subs 337 and 372. I performed the financial analysis in the two audit reports on Mid-South Water Systems, Inc., Docket No. W-100, Sub 21. I testified in the application to transfer of the CPCN from North Topsail Water and Sewer, Inc. to Utilities, Inc., in Docket No. W-1000, Sub 5. I have filed testimony on rainfall normalization with respect of water sales in Docket No. W-274, Sub 160.

With regard to the 1996 Safe Drinking Water Act, I was a member of the Small Systems Working Group that reported to the National Drinking Water Advisory Council of the U.S. Environmental Protection Agency. I have published an article in the National Regulatory Research Institute's Quarterly Bulletin entitled Evaluating Water Utility Financial Capacity.

Table 1:

Projected Gas Prices in Nominal Dollars
(nominal dollars per million Btu)

	2012	2013	2014	2015	2016	2017	2018	2019
AEO 2008	7.26	7.11	7.02	7.00	7.07	7.27	7.48	7.71
AEO 2009	5.87	5.99	6.28	6.66	7.03	7.41	7.84	8.34
AEO 2010	6.53	6.40	6.47	6.77	6.99	7.13	7.32	7.53
AEO 2011	4.81	4.87	4.92	5.10	5.25	5.40	5.57	5.76
AEO 2012	4.51	4.61	4.65	4.90	4.92	5.00	5.13	5.33
AEO 2013	3.38	3.85	3.94	4.09	4.64	4.89	5.25	5.47
AEO 2014		4.39	4.62	4.65	4.77	5.07	5.56	5.77
AEO 2015			5.33	4.82	5.05	5.20	5.56	6.31
AEO 2016				3.39	3.67	4.21	4.55	4.93
AEO 2017					3.06	3.66	4.02	4.51
AEO 2018						3.53	3.72	4.17
AEO 2019							3.34	3.28
AEO 2020								2.86
Actual in Nominal$	3.45	4.37	5.03	3.27	2.88	3.39	3.55	2.88
Average Absolute Difference	1.62	0.93	0.77	2.14	2.63	2.27	2.28	3.08

Table 2:

Percent Differences of the Projected Gas Prices vs. Actual Prices
(overestimates are blue; underestimates are light green)

	2012	2013	2014	2015	2016	2017	2018	2019
AEO 2008	**110.1**	**62.7**	**39.5**	**114.4**	**145.2**	**114.1**	**110.9**	**168.1**
AEO 2009	**69.9**	**37.3**	**24.9**	**103.8**	**143.8**	**118.4**	**121.1**	**190.0**
AEO 2010	**89.1**	**46.5**	**28.6**	**107.4**	**142.4**	**110.1**	**106.4**	**161.7**
AEO 2011	**39.1**	**11.6**	**-2.2**	**56.1**	**81.9**	**59.1**	**57.2**	**100.3**
AEO 2012	**30.4**	**5.6**	**-7.6**	**50.1**	**70.7**	**47.2**	**44.6**	**85.2**
AEO 2013	-2.1	-11.9	-21.6	25.4	60.8	44.0	48.1	90.1
AEO 2014		0.4	-8.2	42.3	65.4	49.4	56.7	100.6
AEO 2015			6.0	47.5	75.0	53.3	56.7	119.2
AEO 2016				3.7	27.4	23.9	28.3	71.4
AEO 2017					6.1	7.8	13.4	56.6
AEO 2018						3.9	4.8	45.1
AEO 2019							-5.8	14.0
AEO 2020								-0.7
Average Absolute Percent Difference	46.8	21.3	15.3	65.5	91.2	66.7	64.4	107.1

Source: https://www.eia.gov/outlooks/aeo/retrospective/

Volatility Evaporates in Natural-Gas Market

By Dan Strumpf
June 6, 2013 11 05 am ET

Volatility has collapsed in the natural gas market.

One measure of volatility, the day day-to-day price moves on the futures market, has shrunk by more than two-thirds over the past eight years, a Wall Street Journal analysis of price data shows. Booming U.S. gas production has led to fewer supply disruptions, smoothing out the big ups and downs that once dominated the market for natural gas.

"If you're looking for big swings, it's not the greatest market to trade," said Aaron Calder, analyst at Gelber & Associates, a Houston energy consulting firm.

That drop in volatility is a big reason why Wall Street banks, commodity trading firms and other financial companies are scaling back their natural-gas storage businesses. With supply so plentiful, natural gas companies are finding that they don't need as much storage on hand as a buffer against disruptions.

In 2005, natural-gas prices hit a record of more than $15 per million British thermal units, and natural gas prices moved an average of 22 cents in a day. A trader who leased storage in the vast underground caverns used to store the fuel could reap big profits by buying up gas when it was cheap and selling it off when a hurricane or a cold winter caused demand to spike.

That's no longer the case. Day-to-day price moves have been shrinking almost every year since 2005. This year, they've moved an average of less than 7 cents a day. On Wednesday, they moved just 0.3 cents.

Natural gas prices aren't just steadier day to day; they also don't fluctuate as much season to season. The price differential between October and January natural gas—a common gauge of the market's need for storage—has also shrunk dramatically. In 2009, October gas was $1.79 per million BTUs cheaper than January gas. Today, that spread has collapsed to just 30 cents.

"The curve is so tight," said Brison Bickerton, managing director at commodity-trading firm Freepoint Commodities. "We will not see a very active season of merchants investing in natural gas."

Public Staff
Hinton Exhibit 2
Page 2 of 2

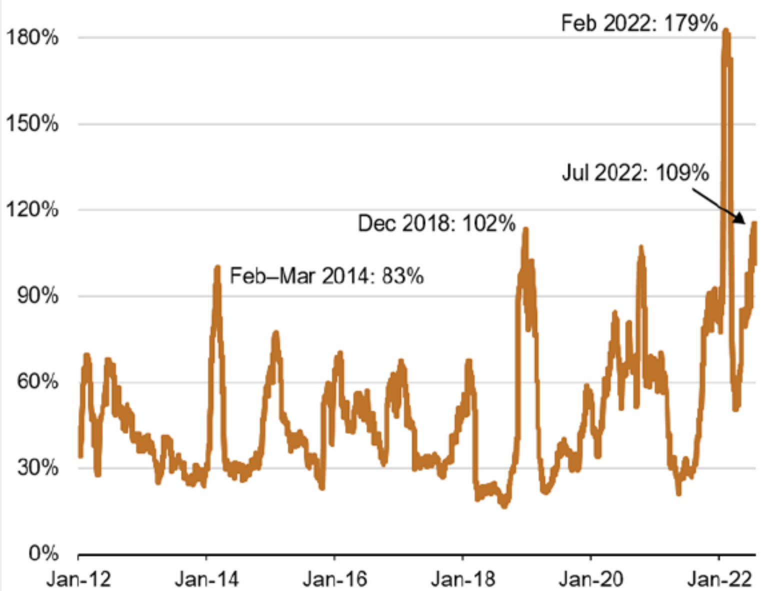
NATURAL GAS

Natural Gas Weekly Update

for week ending August 10, 2022 | Release date: August 11, 2022 | Next release: August 18, 2022 | Previous weeks

Volatility | Prices & volatility

Natural gas 30-day historical volatility (Jan 2012–Jul 2022)
annualized percentage



Data source: Bloomberg L.P.
Notes: Annualized percentage = the standard deviation for the previous 30 days of daily changes in the Henry Hub front-month futures price multiplied by the square root of 252 (number of trading days in a year) multiplied by 100. Percentages are averages for that period.

Spot prices | Spot prices table | NYMEX prices | NGPL prices

JUMP TO PRICES | SUPPLY AND DEMAND | LIQUEFIED NATURAL GAS (LNG) | RIG COUNT | STORAGE | OTHER MARKET DRIVERS

In the News:

Natural gas price volatility reached an all-time high in first-quarter 2022

Natural gas price volatility—a measure of how much daily prices change—reached he highest levels in 20 years in the first quarter of 2022 in the United States. The 30-day historical volatility of U.S. natural gas prices, based on the Henry Hub front-month futures price, averaged 179% in February compared with the five-year (2017–21) average of 48%.

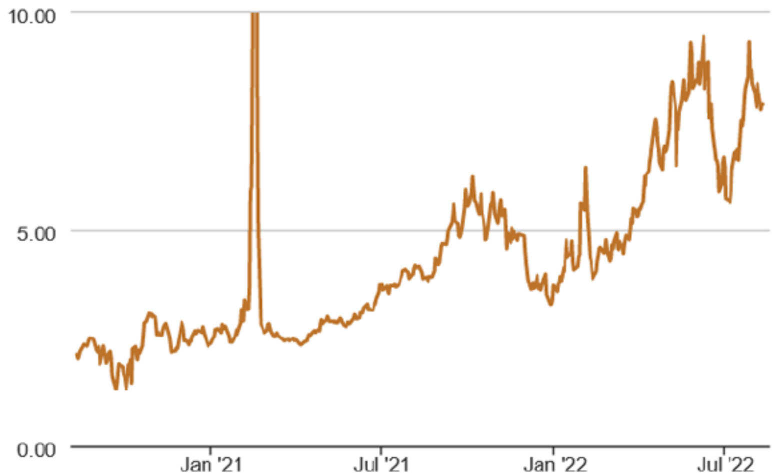
Historical volatility—a measure of how much the daily closing price for a commodity changes during a specific time in the past—was lower in July, when natural gas prices were relatively higher than in the first quarter. In July, the Henry Hub front-month futures price averaged $7.19 per million British thermal units (MMBtu) compared with an average of $4.46/MMBtu in February. In the first quarter of 2022, natural gas price volatility averaged 124% compared with 75% in the second quarter.

Periods of high price volatility can occur as a result of increased uncertainty surrounding material changes in market conditions that affect natural gas supply and demand. Events that could contribute to changing market conditions include production freeze-offs, storms, unplanned pipeline maintenance and outages, significant departures from normal weather, changes in the disposition of inventory levels, the availability of substitute fuels, the level of imports or exports, or other sudden changes in demand.

Volatility in the Henry Hub front-month futures price was particularly high during the first quarter of 2022. U.S. natural gas price volatility is typically higher during the first quarter because of space-heating demand for natural gas. Factors contributing to heightened volatility in the first three months of this year include weather-driven fluctuations in natural gas demand, a decrease in natural gas production from the end of 2021, declines in Lower 48 states' working gas levels, and record U.S. LNG exports to Europe to help offset reduced natural gas supplies from Russia.

Natural gas price volatility fell to an average 56% in April but has risen in subsequent months, averaging 109% in July. Contributing to this increase is both warmer-than-normal weather and increased domestic supply following the fire and subsequent outage of the Freeport LNG export terminal on June 8, 2022.

Natural gas spot prices (Henry Hub)
dollars per million British thermal units



Data source: Natural Gas Intelligence

Note: Henry Hub prices reported for February 16 and 17, 2021, exceeded the published range, averaging $16.96/MMBtu and $23.61/MMBtu, respectively.

Supply table | Demand table | Daily supply/demand graph

U.S. natural gas supply - Gas Week: (8/4/22 - 8/10/22)

	Average daily values (billion cubic feet)		
	this week	**last week**	**last year**
Marketed production	111.0	110.7	106.0
Dry production	98.1	97.9	93.7
Net Canada imports	5.2	5.6	4.6
LNG pipeline deliveries	0.1	0.1	0.1
Total supply	103.4	103.5	98.3

Data source: PointLogic
Note: This table reflects any data revisions that may have occurred since the previous week's pos ing. Liquefied natural gas (LNG) pipeline deliveries represent natural gas sendout from LNG import terminals.

Rigs graph | Rigs table

Public Staff
Hinton Exhibit 3
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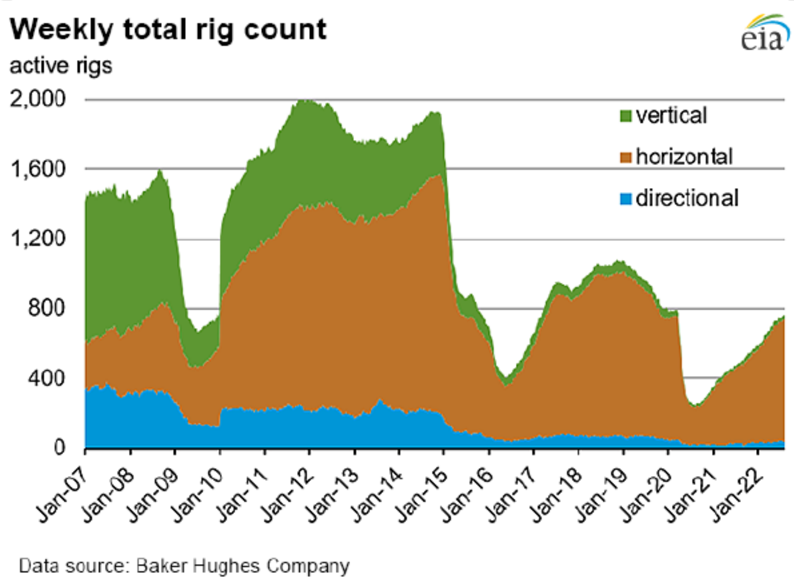
The temporary shutdown of the Freeport LNG terminal resulted in demand for feed gas declining about 2 billion cubic feet per day (Bcf/d) and generated a potential surplus in the domestic market. The immediate market reaction to the Freeport LNG outage was a decline in the Henry Hub futures price, which fell by 39% from June 10 to June 30. In July, however, the higher-than-normal temperatures across much of the United States resulted in strong natural gas demand in the electric power sector, which absorbed much of the Freeport LNG-related surplus and kept natural gas inventories from rising faster. As a result, natural gas futures prices increased 52% from June 30 to July 29 amid high price volatility.

Market Highlights:

(For the week ending Wednesday, August 10, 2022)

Prices

- **Henry Hub spot price:** The Henry Hub spot price rose 6 cents from $7.83 per million British thermal units (MMBtu) last Wednesday to $7.89/MMBtu yesterday.
- **Henry Hub futures prices:** The price of the September 2022 NYMEX contract decreased 6 cents, from $8.266/MMBtu last Wednesday to $8.202/MMBtu yesterday. The price of the 12-month strip averaging September 2022 through August 2023 futures contracts declined 2 cents to $6.732/MMBtu.
- **Select regional spot prices:** Natural gas spot prices rose at most locations this report week (Wednesday, August 3 to Wednesday, August 10). Price increases ranged from 6 cents at Henry Hub to 83 cents at SoCal Citygate in Southern California. Algonquin Citygate and Transco Zone 6, among the few regions where prices decreased week over week, fell by 89 cents and 68 cents, respectively.
  - The price at PG&E Citygate in Northern California rose 36 cents, up from $8.78/MMBtu last Wednesday to $9.14/MMBtu yesterday. The price at SoCal Citygate in Southern California increased 83 cents from $9.38/MMBtu last Wednesday to $10.21/MMBtu yesterday. In northern California, PG&E's maintenance schedule includes work on the Redwood pipeline and Buckeye station beginning August 6 through the end of the month. The Redwood pipeline delivers natural gas from Malin, Oregon, to the San Francisco Citygate. PG&E expects available pipeline capacity to be between 70% and 90% for the next few weeks. In the Southwest, El Paso Natural Gas Company reported pipeline remediation on Line 1100 from Wenden, Arizona, to Ehrenberg, Arizona, one of the main delivery points into the SoCalGas service territory, beginning August 8 through at least the end of the month. In addition to the 450 million cubic feet per day (MMcf/d) currently unavailable with the on-going repair of Line 2000, this remediation reduces pipeline capacity by close to another 180 MMcf/d.
  - At the Algonquin Citygate, which serves Boston-area consumers, the price went down 89 cents from the weekly



Storage graph | Stocks table | History table

- Temperature table
- Average temperature
- Deviation from normal

Temperature – heating & cooling degree days (week ending Aug 04)

	HDDs			CDDs		
Region	Current total	Deviation from normal	Deviation from last year	**Current total**	Deviation from normal	Deviation from last year
New England	0	-2	-7	69	25	54
Middle Atlantic	0	-3	-3	70	11	42
E N Central	1	-3	-4	57	1	24
W N Central	1	-2	-1	71	1	12
South Atlantic	0	0	0	109	12	15
E S Central	0	0	0	97	3	8
W S Central	0	0	0	143	17	20
Mountain	0	-2	0	80	3	-4
Pacific	0	-2	0	73	26	-4
United States	0	-2	-2	86	12	18

Data source: Na ional Oceanic and Atmospheric Administration
Note: HDDs=heating degree days; CDDs=cooling degree days

Average temperature (°F)

7-day mean ending Aug 04, 2022

high of $8.53/MMBtu last Wednesday to $7.64/MMBtu yesterday. The daily high temperature in the Boston area fell to 72°F yesterday, 5°F below normal, and temperatures are forecast to be close to seasonal normals over the weekend and into next week. During this report week, however, the daily high temperature reached 98°F four days out of seven. Natural gas consumption in the New England electric power sector increased 0.3 billion cubic feet per day (Bcf/d), or 17%, according to data from PointLogic. At the Transco Zone 6 trading point for New York City, the price decreased 68 cents from $8.11/MMBtu last Wednesday to $7.43/MMBtu yesterday. Similar to New England, New York City daily high temperatures were above 90°F for most of the report week and temperatures are expected to decline closer to normal levels.

- The FGT Citygate spot price decreased $1.39 from $11.95/MMBtu last Wednesday to $10.56/MMBtu yesterday. The FGT Citygate price reflects deliveries into Florida via the Florida Gas Transmission pipeline. Despite three weeks of price declines of nearly $1.00 or more week over week, the FGT Citygate price remains elevated, and traded at a $2.67/MMBtu premium to Henry Hub yesterday. A constraint at Compressor Station 60 (CS 60) on William's Transco pipeline, which serves the Gulf Coast and Southeast regions, continues to affect the region. CS 60 is approximately 25 miles north-northwest of Baton Rouge in Louisiana.

Daily spot prices by region are available on the EIA website.

- **International futures prices:** According to Bloomberg Finance, L.P., weekly average futures prices for liquefied natural gas (LNG) cargoes in East Asia increased 65 cents to a weekly average of $44.61/MMBtu, and natural gas futures for delivery at the Title Transfer Facility (TTF) in the Netherlands, the most liquid natural gas spot market in Europe, decreased 38 cents to a weekly average of $59.16/MMBtu.
- **Natural gas plant liquids prices:** The natural gas plant liquids composite price at Mont Belvieu, Texas, fell by 49 cents/MMBtu, averaging $10.90/MMBtu for the week ending August 10. Weekly average natural gas prices at the Houston Ship Channel fell 1%, while the price of ethane fell 4%, narrowing the ethane premium to natural gas by 26%. The price of ethylene rose 2%, widening the ethylene to ethane spread by 32%. Propane and normal butane prices fell 5% along with Brent crude oil, which also fell 5%, narrowing the propane discount to crude oil. The isobutane and natural gasoline prices fell 4% and 3%, respectively.

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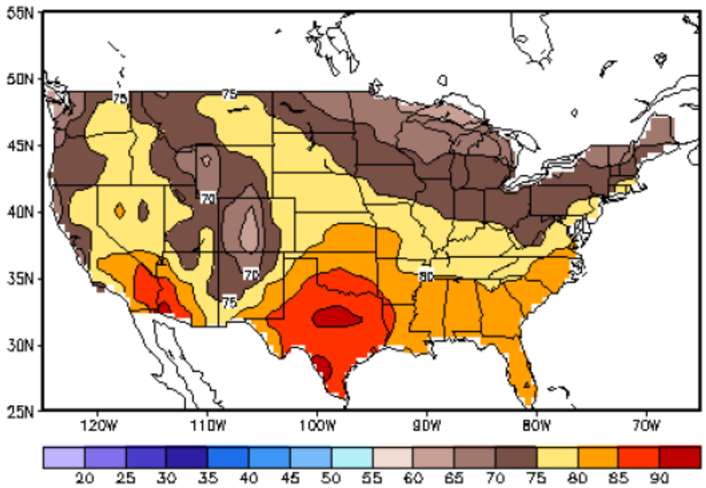
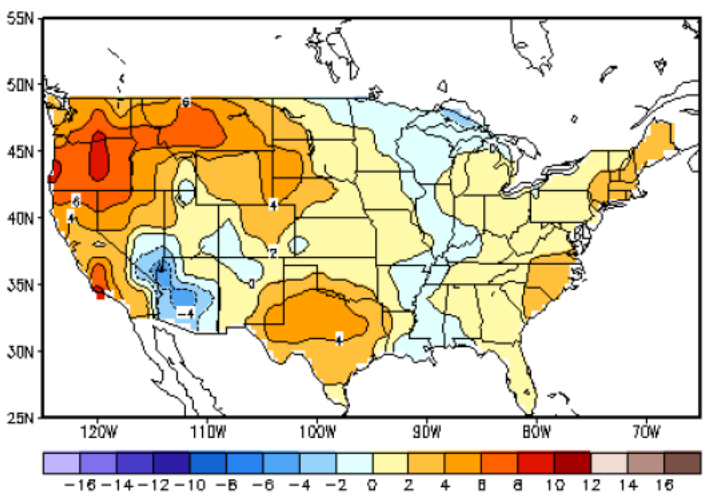
Supply and Demand



Data source: National Oceanic and Atmospheric Administration

Deviation between average and normal temperature (°F)

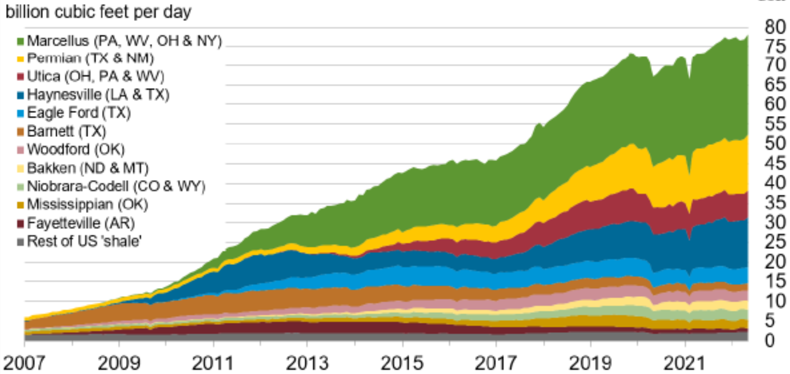
7-day mean ending Aug 04, 2022



Data source: National Oceanic and Atmospheric Administration

Monthly dry shale gas production

billion cubic feet per day



Data source: Enverus state administrative data. Data are through May 2022 and represent EIA's official tight gas estimates but are not survey data. State abbreviations indicate primary state(s).

Note: Improvements to play identification methods have altered production volumes of various plays.

figure data

- **Supply:** According to data from PointLogic, the average total supply of natural gas fell by 0.1% (0.1 Bcf/d) compared with the previous report week. Dry natural gas production grew by 0.2% (0.2 Bcf/d) compared with the previous report week. Average net imports from Canada decreased by 6.0% (0.3 Bcf/d) from last week.
- **Demand:** Total U.S. consumption of natural gas rose by 2.7% (1.9 Bcf/d) compared with the previous report week, according to data from PointLogic. Natural gas consumed for power generation climbed by 4.0% (1.7 Bcf/d) week over week as above normal temperatures in the Northeast increased demand for air conditioning. U.S. Industrial sector consumption increased by 0.6% (0.1 Bcf/d) week over week. In the residential and commercial sectors, consumption increased by 1.4% (0.1 Bcf/d). Natural gas exports to Mexico decreased 3.3% (0.2 Bcf/d). Natural gas deliveries to U.S. LNG export facilities (LNG pipeline receipts) averaged 10.8 Bcf/d, or 0.1 Bcf/d lower than last week.

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Liquefied Natural Gas (LNG)

- **Pipeline receipts:** Natural gas deliveries to LNG export terminals in South Louisiana and South Texas were essentially flat this week at 7.4 Bcf/d and 2.3 Bcf/d, respectively. Natural gas deliveries to terminals along the East Coast decreased slightly, by less than 0.1 Bcf/d, to 1.0 Bcf/d. Deliveries to Calcasieu Pass in Louisiana were on average about 400 MMcf/d lower than last week, whereas deliveries to Sabine Pass, also in Louisiana, averaged about 300 MMcf/d higher than a week ago.
- **Vessels departing U.S. ports:** Seventeen LNG vessels (eight from Sabine Pass, four Corpus Christi, three from Cameron, and one each from Calcasieu Pass and Cove Point) with a combined LNG-carrying capacity of 64 Bcf departed the United States between August 4 and August 10, according to shipping data provided by Bloomberg Finance, L.P.

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Rig Count

- According to Baker Hughes, for the week ending Tuesday, August 2, the natural gas rig count increased by 4 rigs from a week ago to 161 rigs. All four rigs were added in unspecified producing regions. The number of oil-directed rigs decreased by 7 to 598 rigs. The Ardmore Woodford, DJ Niobrara, Granite Wash, and Williston each added one rig. The Cana Woodford dropped one rig, the Permian Basin dropped four rigs, and six rigs were dropped from unspecified producing regions. The total rig count now stands at 764 rigs.

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Storage

- The net injections into storage totaled 44 Bcf for the week ending August 5, compared with the five-year (2017–2021) average net injec ions of 45 Bcf and last year's net injections of 44 Bcf during the same week. Working natural gas stocks totaled 2,501 Bcf, which is 338 Bcf (12%) lower than the five-year average and 268 Bcf (10%) lower than last year at this time.
- According to *The Desk* survey of natural gas analysts, estimates of the weekly net change to working natural gas stocks ranged from

net injections of 30 Bcf to 47 Bcf, with a median estimate of 40 Bcf.

- The average rate of injections into storage is 5% lower than the five-year average so far in the refill season (April through October). If the rate of injections into storage matched the five-year average of 9.3 Bcf/d for the remainder of the refill season, the total inventory would be 3,307 Bcf on October 31, which is 338 Bcf lower than the five-year average of 3,645 Bcf for that time of year.

More storage data and analysis can be found on the *Natural Gas Storage Dashboard* **and the** *Weekly Natural Gas Storage Report*.

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Other Market Drivers

Natural Gas Pipeline Company of America declared a force majeure at segment 26 of the Gulf Coast #3 main line, which runs from Cass County, Texas, to Montgomery County, Texas, from August 9 through August 12. The company is performing pipeline remediation work between Compressor Station 304 (CS 304) in Harrison County, Texas, and Compressor Station 303 (CS 303) in Angelina County, Texas, that results in a reduction of maximum operating capacity. Throughput capacity southbound through CS 303 is reduced and limited to no less than 79% of the design capacity of approximately 1.7 MMcf/d.

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See also:

- Natural Gas Analysis Reports
- Short-Term Energy Outlook