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NATURAL GAS WEEK®

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METHANE

Methane Woes Vex Permian Producers' Effort to Win Gas Customers

A growing glut of associated gas in the Permian has producers eyeing growing markets along the US Gulf Coast, particularly LNG exports. But the region's methane problem may prove an obstacle to competing in those arenas, especially as competing plays take collective action to improve methane intensity at a basin-wide level.

"A gassier Permian is going to set up a clash between US producers and potential buyers looking to minimize their supply chain emissions," Jim Krane, a fellow for energy studies at Rice University's Baker Institute, told Energy Intelligence. "It's going to be up to the [Texas] Railroad Commission to decide. Are we going to keep permitting oil-focused operations with no capacity to market the associated gas? Are we going to maintain the view that gas is a waste product?"

If that's the case, "the Permian producers are going to come under more scrutiny for flaring and venting, which will eventually bleed into their ability to attract investment and for US LNG exports to compete on a carbon basis with cleaner producers," Krane said.

The US Energy Information Administration (EIA) estimates the Permian today produces about 21.6 billion cubic feet per day, dwarfed only by Appalachia's 35.3 Bcf/d. A trio of long-haul pipelines totaling 6.1 Bcf/d of capacity running from West Texas oilfields to the Texas Gulf Coast entered service in 2021, enabling the region's latest gas production surge. In February, Permian gas output will have grown 2.8 Bcf/d year over year, the fastest rate of all seven major US shale plays, the EIA estimates.

Despite that scale, the Permian is predominantly an oil play, and that complicates the picture when it comes to methane intensity, said Amber McCullagh, senior advisor at Validere, a company that provides methane measurement, reporting and verification services to the oil and gas industry.

"Most measurement-based, third-party studies find higher methane intensity for Permian volumes relative to other basins," she told Energy Intelligence. "But often third parties calculate methane intensity as volume vented as a share of sales gas, effectively attributing all Permian methane emissions to its gas production. We think this metric disadvantages mixed-phase plays like the Permian and doesn't give as full a picture of the emissions intensity of their entire operation relative to other basins."

"To avoid flaring — which itself contributes to higher methane emissions rates via things like unlit flares — Permian operators need to have sufficient gas gathering infrastructure, access to enough gas processing capacity, and sufficient residue gas takeaway," McCullagh said. "This infrastructure takes time to build and generally

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KEY WEEKLY SPOT PRICES*

Flow Dates: 1/18-1/23

	$/MMBtu	Chg.	High	Low
Henry Hub	3.19	-0.25	3.50	2.90
Transco Z6 - NY	2.89	-0.37	3.00	2.80
Algonquin	4.05	-1.60	5.50	3.18
Eastern Gas South	2.58	-0.09	2.70	2.38
Chicago Citygate	3.04	-0.10	3.15	2.90
NNG Ventura	3.03	-0.24	3.17	2.95
Waha Hub	1.14	2.32	2.35	0.30
Katy Hub	2.64	-0.24	2.80	2.25
SoCal Border	17.16	-0.98	23.50	14.00
NW Rockies	15.73	0.47	21.00	14.00
NW Sumas	16.00	2.75	19.50	13.00
AECO	2.67	-0.02	2.93	2.43

>> *Full table on page 2

NATURAL GAS WEEKLY SPOT PRICES

Flow Dates: 1/18-1/23

Price Point	$/MMBtu	Chg.	High	Low	Avg. Daily Vol.	Avg. Daily Deals	Jan Bid Week
GULF COAST							
ANR SE	3.10	-0.34	3.40	2.90	52,500	6	4.83
Col. Gulf - Erath	3.00	-0.39	3.15	2.85	17,600	3	--
Col. Gulf - Rayne	2.93	-0.03	2.96	2.72	33,629	6	4.26
Florida Zone 1	2.72	-0.39	2.72	2.72	714	1	4.63
Florida Zone 2	--	--	--	--	--	--	5.05
Florida Zone 3	3.17	-0.37	3.40	2.92	61,044	12	5.41
Henry Hub	3.19	-0.25	3.50	2.90	94,971	10	4.75
NGPL-LA	--	--	--	--	--	--	--
Pine Prairie Hub	3.04	-0.33	3.29	2.89	28,443	5	--
Sonat	3.04	-0.36	3.20	2.81	113,300	16	4.86
Tenn 500 So LA Z1	2.96	-0.39	3.19	2.80	38,457	6	4.62
Tenn 800 So LA Z1	2.81	-0.33	2.89	2.70	4,800	1	4.58
Tetco ELA	2.84	-0.28	2.93	2.75	16,871	3	4.36
Tetco WLA	3.10	-0.23	3.35	2.84	36,729	6	4.56
TGT Zone SL	--	--	--	--	--	--	--
Transco Station 45	--	--	--	--	--	--	4.75
Transco Station 65	3.13	-0.38	3.39	2.92	210,678	24	5.34
Trunkline ELA	--	--	--	--	--	--	--
Trunkline WLA	--	--	--	--	--	--	--
Trunkline Zone 1A	2.87	-0.15	2.96	2.75	38,386	6	4.64
Regional Average	*3.08*	*-0.29*					*5.13*
TEXAS (SOUTH/EAST)							
Carthage Hub	2.70	-0.02	2.90	2.40	107,986	10	3.26
Houston Ship Channel	2.58	-0.24	2.75	2.20	44,543	6	4.40
Katy Hub	2.64	-0.24	2.80	2.25	106,314	15	--
NGPL-South Texas	2.72	-0.07	2.81	2.54	61,971	9	--
NGPL-TexOk	2.78	-0.11	2.87	2.50	164,657	24	--
Tenn Zone 0	2.62	-0.23	2.85	2.52	39,614	8	3.91
Tetco-East Texas	2.81	-0.06	2.85	2.80	2,857	1	--
Tetco-South Texas	2.78	-0.23	2.88	2.68	9,143	1	--
TGT Zone 1	2.88	-0.09	2.96	2.75	43,929	9	4.38
Transco Station 30	2.69	-0.35	2.81	2.40	11,714	2	4.55
Tres Palacios Hub	2.83	-0.19	3.10	2.45	23,314	4	--
Regional Average	*2.72*	*-0.17*					*4.14*
TEXAS (WEST)							
El Paso Permian	1.13	0.65	3.20	--	57,014	12	5.41
NNG Custer	--	--	--	--	--	--	--
Transwes E of Thoreau	1.92	0.91	2.50	0.10	23,971	4	--
Waha Hub	1.14	2.32	2.35	0.30	42,000	8	4.78
Regional Average	*1.29*	*1.41*					*5.15*
MIDCONTINENT							
ANR SW	2.98	-0.40	3.01	2.95	5,571	1	7.16
CenterPoint East	2.73	-0.10	2.85	2.60	34,914	6	--
CenterPoint West	--	--	--	--	--	--	--
NGPL-MC	2.81	-0.04	2.90	2.67	107,727	18	--
Oneok	2.70	-0.10	2.76	2.50	63,314	9	5.86
Panhandle	2.85	0.07	2.90	2.66	52,243	10	--
Southern Star	2.88	-0.21	3.20	2.80	9,686	1	--
Regional Average	*2.79*	*-0.06*					*6.66*
GREAT PLAINS							
Emerson	3.09	-0.03	3.28	3.00	44,000	9	5.01
NB Ventura TP	3.01	-0.19	3.17	2.93	23,986	2	--
NGPL Amarillo	2.94	-0.08	2.95	2.90	2,443	1	--
NNG Demarc	3.03	-0.25	3.14	2.90	19,343	2	7.91
NNG Ventura	3.03	-0.24	3.17	2.95	60,843	10	7.91
Regional Average	*3.04*	*-0.14*					*5.65*
UPPER MIDWEST							
Alliance	3.07	-0.11	3.19	2.95	63,114	10	--
ANR ML7	--	--	--	--	--	--	--
Chicago Citygate	3.04	-0.10	3.15	2.90	187,512	26	6.11
Consumers	3.10	-0.11	3.23	3.00	146,171	21	4.57
MichCon	3.09	-0.13	3.24	2.98	130,514	20	4.33
REX Zone 3 Delivered	2.87	-0.16	3.12	2.60	150,283	16	5.57
Regional Average	*3.03*	*-0.13*					*4.49*

Price Point	$/MMBtu	Chg.	High	Low	Avg. Daily Vol.	Avg. Daily Deals	Jan Bid Week
SOUTHEAST							
Tetco M1	2.85	-0.23	2.85	2.85	357	1	--
Transco Zone 4	3.14	-0.44	3.45	2.90	327,300	48	5.40
Transco Zone 5	3.80	-0.52	4.10	3.05	233,629	38	13.71
Regional Average	*3.41*	*-0.37*					*5.47*
APPALACHIA							
Col. Gas App. Pool	2.71	-0.10	2.80	2.53	30,843	6	4.02
Eastern Gas North	2.52	-0.04	2.68	2.44	6,929	2	3.86
Eastern Gas South	2.58	-0.09	2.70	2.38	192,714	22	3.65
Lebanon Hub	2.97	-0.13	3.30	2.78	27,943	4	--
Millennium, East Receipts	2.80	-0.06	2.90	2.65	32,044	5	3.89
TENN Z4 200-leg	2.77	-0.11	2.85	2.58	36,167	6	4.20
TENN Z4 300 leg, receipts	2.61	-0.18	2.77	2.57	8,586	1	3.85
TENN Z4 313 pool	2.70	-0.12	2.80	2.62	9,408	1	3.91
Tetco M2	2.62	-0.15	2.68	2.44	14,886	3	3.75
Transco Leidy Line	2.71	0.02	2.78	2.59	17,368	3	4.00
Regional Average	*2.66*	*-0.11*					*3.98*
EASTERN CANADA							
Dawn	3.16	-0.11	3.37	3.00	257,771	38	4.70
Iroquois	3.40	-0.45	3.60	3.20	96,178	17	--
Niagara	--	--	--	--	--	--	4.81
Regional Average	*3.23*	*-0.20*					*4.70*
NORTHEAST / MIDATLANTIC							
Algonquin	4.05	-1.60	5.50	3.18	74,930	15	23.54
Dracut	4.88	-1.83	6.00	4.50	1,732	1	--
Iroquois Zone 2	3.77	-1.95	4.25	3.30	48,381	10	21.06
Tenn Gas Zone 6	4.56	-1.72	7.00	3.20	58,795	12	20.71
Tetco M3	3.00	-0.20	3.20	2.70	49,480	12	12.50
Transco Z6 - Non-NY	3.00	-0.19	3.30	2.78	14,414	3	12.91
Transco Z6 - NY	2.89	-0.37	3.00	2.80	2,786	1	15.71
Regional Average	*3.84*	*-1.52*					*17.63*
ROCKIES							
Cheyenne Hub	3.03	-0.07	3.20	2.85	48,643	8	8.60
CIG	3.12	-0.01	3.20	2.91	22,157	5	8.50
Kern River / Opal	17.11	0.00	21.50	13.90	48,386	12	55.88
NW Rockies	15.73	0.47	21.00	14.00	7,986	2	26.00
Questar	--	--	--	--	--	--	26.00
White River Hub	14.93	7.04	21.25	14.00	11,057	2	--
Regional Average	*9.66*	*-3.46*					*44.98*
SAN JUAN BASIN							
El Paso Bondad	15.33	5.39	19.00	14.15	13,214	2	--
El Paso San Juan	15.98	6.07	22.00	13.00	69,600	15	31.79
Transwestern, San Juan	15.39	7.08	20.00	13.00	47,671	7	40.07
Regional Average	*15.70*	*6.10*					*36.93*
PACIFIC NORTHWEST/WESTERN CANADA							
AECO	2.67	-0.02	2.93	2.43	178,149	36	3.73
Kingsgate	3.28	-0.14	3.40	3.20	2,300	1	--
Malin	16.44	-0.68	21.40	14.00	14,614	3	43.38
NW Sumas	16.00	2.75	19.50	13.00	32,054	6	43.90
Stanfield	16.00	-0.67	21.00	14.20	15,000	3	--
Westcoast Station 2	2.63	0.07	2.91	2.42	30,235	8	3.03
Regional Average	*5.71*	*0.68*					*19.18*
CALIFORNIA							
El Paso - South Mainline	18.01	-0.67	23.00	14.25	34,729	7	--
Kern - Wheeler Ridge	20.50	2.16	20.50	20.50	430	1	--
Kern River Delivered	16.32	-1.60	22.75	14.00	46,186	11	--
PG&E Citygate	18.27	0.92	22.25	14.60	33,529	6	50.16
PG&E South	17.04	-0.58	22.00	13.50	55,600	11	39.29
SoCal Border	17.16	-0.98	23.50	14.00	32,142	9	42.01
SoCal Citygate	16.46	-4.37	23.75	14.50	48,848	12	58.31
Regional Average	*17.11*	*-1.84*					*51.69*
WEEKLY COMPOSITE SPOT PRICES							
Delivered	6.48	-1.97					
Wellhead	3.99	0.49					

MARKET VIEW

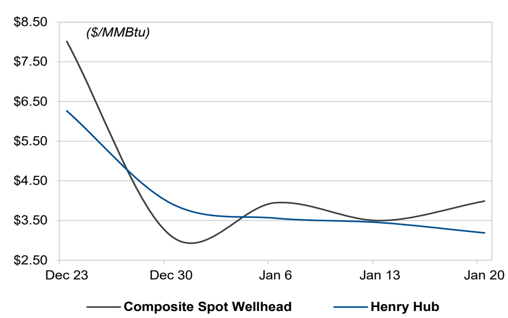
Gas Price Recovery May Require Another Test of US Energy Grid

February gas futures fell 10.1¢ Friday to end the week down 24.5¢ at $3.174 per million Btu, a fresh 18-month low for the prompt-month contract. Abnormally mild temperatures have pulled the market to fresh lows, and whether — and by how much — prices can recover could hinge on how much of a test of the US energy grid will face in its next bout of winter weather.

"Even with the potential for at least another two sizeable bearish [storage] withdrawals on the horizon, unless there are some big surprises from Mother Nature over the next few weeks, the 2022-23 winter will retain its position as the smallest to-date draw in the last five years well into February," Gelber & Associates analysts said Friday. "Weather will still play a large role in the bullishness or bearishness of Nymex gas futures prices. But without meaningful, extended cold periods in the longer-range forecasts, it sets up end-of-season gas storage to potentially land in notably bearish territory by Apr. 1."

This winter, "any sort of upside traction in the near term" would require at least one more weekly storage withdrawal exceeding 200 billion cubic feet, they said. And that would require another bout of exceptional winter weather.

AVERAGE CASH PRICES



Withdrawals of that magnitude were last seen in late December, when a massive storm brought blizzards, high winds and extremely low temperatures to large portions of the US. From Dec. 21-26, residential and commercial gas demand averaged 60.9 billion cubic feet per day, 55% above the five-year average for the period, while power-sector gas consumption averaged 37.8 Bcf/d, up 45% from the five-year average, according to the US Energy Information Administration (EIA).

At the same time, "production fell rapidly, creating an imbalance that led to large withdrawals from storage and increased natural gas pipeline imports from Canada," the EIA said, with production reaching a low of 82.5 billion cubic feet on Dec. 24. "The last time the US saw such a large and rapid decline in dry natural gas production was during a February 2021 winter storm," which led to a deadly power crisis in Texas.

Deficit Flips to Surplus

Season-to-date, the market has drawn 760 Bcf from the nation's gas storage stockpiles, which is 213 Bcf below the five-year average pace. The EIA reported an 82 Bcf withdrawal for the week ending Jan. 13, decreasing net working gas inventories to 2,820 Bcf.

The draw was 11 Bcf above consensus but was 74 Bcf lower than the five-year average, flipping the deficit to a 53 Bcf, or 1.2%, surplus to the five-year average. Next week's data is expected to show a 78 Bcf withdrawal versus the average of 185 Bcf, further widening the surplus.

Besides weather, market observers are watching for the restart of Freeport LNG. But its 2 Bcf/d of demand would only absorb 140 Bcf of US gas production if it were to run at maximum capacity beginning Jan. 21.

The weather has supply-demand balances significantly looser than a year ago. US dry gas production averaged 100.5 Bcf/d in the week ending Jan. 18, up 5.5 Bcf/d from a year earlier, while domestic consumption fell 7.5 Bcf/d year over year to 93.5 Bcf/d, driven primarily by a 7.7 Bcf/d decline in residential and commercial demand the EIA pegged at 37.6 Bcf/d.

In its latest *Drilling Productivity Report*, the EIA estimates gas production at the nation's major shale plays will have climbed 9.13 Bcf/d year over year to 96.66 Bcf/d, led by 2.79 Bcf/d growth in the Permian Basin, where most drillers are targeting oil.

In the gassier Haynesville Shale, the EIA estimates gas production will climb 2.02 Bcf/d year over year to reach 16.58 Bcf/d, while it expects Appalachian output to climb 1.74 Bcf/d over the same period to 35.37 Bcf/d.

The EIA bases its projections on the number of drilling rigs at work and their productivity. But prices are approaching levels — the 12-month strip is at $3.525/MMBtu and the 2024 strip is at $3.992/MMBtu — where major producers have said they would consider a pullback in activity.

"If you saw prices throughout the curve fall down into the mid- to low-$3s, we'd probably pull back a bit," Chesapeake Energy CEO Domenic Dell'Osso told investors last fall. "I think we still make a good bit of money at that level, but it would be an indication to us that the supply-demand fundamentals are weaker than we probably expect as we sit here today."

Everett Wheeler, Washington

Methane >> continued from page 1

also long-term commitments, and delays or mistiming in any part of that buildout will cause either higher emissions or deteriorating capital efficiency if operators delay completions until infrastructure is in place.

In part, Permian emissions are worse because the infrastructure development challenge is genuinely harder, not because its operators are more careless."

Krane said he suspects that "self-interest will eventually convince Permian producers to do the right thing, even if the Railroad Commission continues greenlighting their worst instincts. Bigger producers are already on board with this."

Indeed, Pioneer Natural Resources CEO Scott Sheffield has called on regulators to rein in private operators that he accuses of excessively flaring. Yet while operators in the Permian have made individual efforts or joined coalitions aimed at curbing methane emissions, so far there is no industry partnership aimed at monitoring and addressing the issue on a Permian-wide basis.

Dearth of New Pipelines

Despite the addition of significant takeaway capacity through 2021, the Permian's infrastructure problem has again been brought to the fore. West Texas natural gas prices have fallen to a significant deficit to Henry Hub, with producers once again intermittently paying customers to take their gas production.

Pioneer CEO Scott Sheffield predicted earlier this month that this pattern will continue to play out for the next decade as the region's largest oil producers will see their gas-to-oil ratios climb.

David Braziel, CEO of energy consulting firm RBN Energy, agreed, predicting that Permian gas production will reach 30 Bcf/d by 2030. "We're talking about wellhead gas, not [pipeline quality] residue gas, which would be closer to 22.5 Bcf/d in 2030," he told Energy Intelligence. "We'll need another 2 Bcf/d of capacity every couple of years given projected growth."

About 3.55 Bcf/d of incremental capacity is slated to come online through the third quarter of 2024. Of that, 2.5 Bcf/d is from the WhiteWater Midstream-led, 490-mile Matterhorn Express Pipeline that will ferry gas from Waha to Katy, Texas.

Kinder Morgan (KMI), the region's largest midstream developer, owns interests in more than 7 Bcf/d of the basin's takeaway capacity. But after building the 2 Bcf/d Gulf Coast Express and 2.1 Bcf/d Permian Highway pipelines, KMI says it is less interested in such large-scale projects.

"We're able to make relatively modest capital efficient investments in our grid to serve the supply and demand growth that we're seeing across the network," KMI CEO Steve Kean told investors Wednesday. "It's a collection of a lot of smaller projects and mostly buildups of the existing network. ... It reduces the execution risk on them, and we get as best a return as we can that's available for the market."

KMI is adding 550 million cubic feet per day of capacity Permian Highway with a target in service date of Nov. 1. But the pipeline developer has put on hold an effort to add additional compression to Gulf Coast Express, a project that would raise capacity by 570 MMcf/d and had been slated to begin operating by December 2023.

"That hasn't been very active, although with lower gas prices now there may be some opportunities there," KMI President of Natural Gas Pipelines Tom Martin said. "As you recall, fuel cost was a bit of a headwind for us on that expansion project. As gas prices are lower, that may bring that one more into an actionable opportunity."

Executives say the company is making progress on commercial discussions regarding another greenfield long-haul pipeline, the 2 Bcf/d Permian Pass pipeline, but there are timelines to consider on the demand side as well.

"What we are hearing from our customers is that the next need for incremental capacity out of the basin is sometime in late 2026, maybe early 2027. And so as we work with our producer customers and also align them with their desired customer, which I think largely are going to be LNG related along the Gulf Coast, we need to figure out exactly where and when those volumes need to be there," Martin said. "So I think that's still out there. The overall market still needs that capacity."

Everett Wheeler, Washington

INDUSTRY TRENDS

MiQ Touts 'Asset-Level' Approach to Cutting Methane Emissions

While methane reduction pledges at the company, country, regional and even global levels are seen as helpful, momentum is growing for assessing methane leaks at the asset level to help gas industry players get a better handle on rising emissions. "You need to look at individual assets to be able to judge the whole of a potential company," Georges Tijbosch, CEO of nonprofit MiQ, told Energy Intelligence.

MiQ has established a methane emissions certified standard and a global database that allows gas producers to know the exact methane emission intensity of the assets they own — and make it known to potential buyers.

MiQ — one of several entities that analyzes and certifies the environmental footprint of gas — currently monitors roughly 4% of global gas supply, with big plans for expansion and serious interest coming from project owners.

Its system is market-oriented because certified gas can be traded and buyers can choose between gas that involved lower or higher methane releases.

"MiQ has taken off with a bang in the US," Tijbosch said. "We are already in advanced conversations in other areas of the world with other producers, such as the North Sea, the Middle East and Asia."

The company's client list is North American-focused, including Exxon Mobil, Chesapeake Energy and EQT, but does include some European players such as BP and Repsol.

"We reached out to these companies and their peers, plus industry organizations, government bodies, NGOs and entities such as the Methane Guiding Principle and the Oil and Gas Climate Initiative (OGCI). There is a lot of interest from the oil and gas industry alongside civil society to solve the problem of methane emissions," Tijbosch said.

He added that MiQ is talking to Shell and other OGCI members and "early this year we will make some announcements about more OGCI members joining the MiQ database. Geographically, it is likely to be more European and Middle East focused companies."

Letter Grades

So why the asset level? "We cover main assets in their totality rather than certifying individual wells to eliminate the risk of operators potentially cherry-picking better-managed wells," Tijbosch explained.

Assets are graded A-F by independent auditors. "I am happy to say there are no F grade assets on there. The vast majority have ratings of A, B or C."

To put things in context OGCI members have committed to be below a methane leakage rate of 0.2% by 2025, which is a C grade in MiQ's ratings, Tijbosch. An A grade has a methane intensity below 0.05%, is monitored quarterly and has stringent company guidelines for methane emission checks.

"This grading system allows buyers to understand the methane emissions from the oil and gas industry from the upstream. The certificates attached to the assets then create pricing signals in the market, and as a consequence, capital flows into the market to address those emissions."

Tijbosch said the biggest challenge with reducing errant methane is locating leaks and having a workable solution to stop and repair faulty equipment. "It is tough to figure out methane emissions in the oil and gas sector. Methane leaks in thousands of places in facilities around the world."

LNG Certification Next

As Europe turns away from Russian pipeline gas, LNG has become more important as a global gas source, but the methane content in the LNG value chain has always been controversial.

"We will be certifying the LNG liquefaction plants, the regas plants and including the methane emissions from the ships transporting the LNG so you get a full value chain certification from producer to consumer," Tijbosch explained. "Gas certified in the US gets exported, so the next step is certifying gas supplied as LNG to Europe. MiQ will only allow this when all of the emissions of the LNG are included, so a UK or European buyer knows when gas lands in a regas terminal they will know the methane emissions of all the different parts further upstream."

Currently, certified gas on the trading hub doesn't include full-chain LNG, but that is the next step, he added, as "there is strong interest for this." A planned LNG facility in Pennsylvania called Penn LNG is committed to purchase 100% MiQ certified gas and certifying the LNG plant, Tijbosch noted.

The MiQ standard and database could arguably provide certainty in countries where there is intense debate around methane emissions, such as in the US. "Companies that are involved with MiQ are ahead of the game," asserts Tijbosch. "Once you establish reference levels, it becomes easier for governments to accept them and legislate for them."

Jason Eden, London

LNG

Freeport Restart Elusive Despite Uptick in Feedgas Volumes

Despite taking in feedgas for several days this week, skepticism about an imminent restart of the Freeport LNG export facility abounds. Refinitiv data shows that the 15 million tons per year (2 billion cubic feet per day) Freeport plant received gas starting last weekend. Market watchers are keeping a close eye on gas flows around the facility — responsible for

17% of the US' LNG export capacity — as it looks to restart following a June 2022 explosion.

After the nine-day steady trickle of about 25 million cubic feet per day of feedgas during December, flows to Freeport started again on Jan. 14, rising quickly from about 44 MMcf/d to 68 MMcf/d before dropping to only 5 MMcf/d on Jan. 18. Preliminary data indicated no feedgas on Jan. 19.

"We are still targeting second half of this month for the safe, initial restart of our liquefaction facility, pending regulatory approvals," Heather Browne, director of corporate communications for Freeport LNG, told Energy Intelligence on Jan. 17.

Yet not all are sure those pending approvals will come in time. Freeport's planned initial restart most recently slid from mid-December to the second half of January due to continued regulatory approval delays — and in spite of feedgas volumes also flowing last month.

Even if Freeport is able to stick to its targeted timeline, full operations would not be expected until March given the time it takes to ramp up.

Regulatory Scrutiny

"The last thing [safety regulators] want is evidence they moved too quickly," said Gary Kruse of DC-based consultancy Arbo, which closely follows US energy regulatory matters.

To actually get approval by the Federal Energy Regulatory Commission (FERC) and Pipeline and Hazardous Materials Safety Administration to restart by the end of January would be a surprise, he told Energy Intelligence. He cited regulators' early December data request from Freeport and insistence they would take their time to read and respond to the information.

Kruse explained that responses to such data requests often take several iterations due to answers that regulators deem insufficient. That said, he said the public does not have a complete view of all supplemental information provided. "There could be more progress than I'm seeing," Kruse said, noting that there is at least a "path to restart" underway.

Perhaps tellingly, market sources say Freeport canceled some upcoming shipments for February loading last week as regulators said they had not received applications yet requesting a restart. Those sources suggest even a February restart of the export terminal looks increasingly unlikely.

Market Impact

When Freeport shut down following an explosion in June, the closure sent US gas prices plummeting by about 21%, heading off a run to $10 per million Btu for July 2022 gas futures as about 2 Bcf/d would suddenly going to be staying home.

The closure conversely caused a spike in the European TTF gas benchmark to about $28/MMBtu as Europe was in a relatively early phase of adjusting to a world without Russian piped gas supplies and looking to the US to fill part of that gap.

Fast forward a few months and Freeport could wake up in an entirely different short-term market, one in which the plant's return will have a limited impact. Europe has since shorn up more than enough gas for this winter, and as a result of that and other market factors, gas prices on both sides of the Atlantic are deflated.

The US February prompt-month futures contract dipped into the $3.20s/MMBtu this week, an 18-month low and about half the price level seen pre-explosion.

Meanwhile, a mid-January plunge took Southwest European spot LNG below July 2021 levels this week. Spot LNG assessments by Energy Intelligence for that region shed $6.15 week on week to settle at $14.15/MMBtu, also about half the pre-shutdown level.

Before Freeport stopped operating, there was a major swing in deliveries from Asia to Europe, according to Kpler data, which underscores Freeport's importance to Europe next winter.

For 2021, the plant's first year operating near capacity, Freeport exported 13.5 million tons — 50% to Asia, 29% to Europe and 20% to the Americas. For the first half of 2022, Freeport's destinations flipped — it exported 6 million tons, 69% to Europe, 19% to Asia and 11% to the Americas.

There is also the issue of the inevitable rise in US gas prices upon Freeport's restart, which will no doubt trigger a round of domestic political handwringing about the impact of LNG exports on US consumers.

Michael Sultan, Washington

POLICY

Looming Sage Grouse Protections Presage New Battle With Drillers

The Biden administration is working on a rewrite of plans for protecting the greater sage grouse, which carries big implications for Western land use and oil and gas producers in those states.

After years of policies over the embattled bird being in flux, the Biden Interior Department is planning amendments to resource management plans to replace 2015 and 2019 versions for preserving the species. That could mean tighter drilling restrictions for the 70 million acres in Western states that serve as habitat.

Most affected would be Colorado, Idaho, Nevada, Northeast California, Utah, Oregon, Wyoming, North Dakota, South Dakota and Montana, which includes several states among the top 10 Us gas producers.

Sage grouse populations are currently hovering around 200,000 and 500,000, according to the Audubon Society. Their numbers have been declining for several years as severe drought, wildfires and the loss of sagebrush on which the bird relies for survival.

But current legislation prohibits Interior from using federal dollars to list the bird as "endangered," a status that would lead to onerous restrictions for oil and gas production.

Drillers for years have fought against more formal restrictions like wide buffer zones separating drilling from critical habitat to protect breeding areas, and the budget law blocking an Endangered Species Act (ESA) listing inoculates gas production somewhat from the most severe limitations.

But there's still plenty to make producers nervous, with courts continuously weighing in on the issue and leases in Western states highly vulnerable to vacatur without updated protections in place.

Kathleen Sgamma, president of the Western Energy Alliance, told Energy Intelligence that the producer group expects the revisions to be "a repeat of what happened during the Obama administration — overestimations of impact from oil and natural gas while ignoring more immediate threats to the sage grouse such as predation and wildfires.

That overestimation causes them to place overly restrictive measures on oil and natural gas while not addressing those things that actually result in bird mortality."

Summer Release Expected

Timing of the revised management plans is not clear, as changes were expected out last year from Interior, though Sgamma said she expects Interior's Bureau of Land Management (BLM) to release draft revisions this summer.

While fraught with potential risk to producers' access to federal lands, updated risk management plans could also provide some degree of certainty given that over the past several years legal challenges over the species have led to adverse outcomes for the industry.

In 2021, for example, a federal judge threw out the Trump Interior Department's plans to scale back protections for the species when located near drilling operations.

Concerns over the ESA protections for the sage grouse have also imperiled federal leases for years. In 2021 a different federal district court in Idaho scrapped leases for wide swaths of Wyoming and Montana, finding that Interior did not adequately consider impacts to sage grouse populations during the Trump administration.

Late last year, the Center for Biological Diversity asked California's state Fish & Game Commission to list the bird under the state's own endangered species law, which would carry restrictions on where drilling can occur on state land.

In its petition, the environmental group listed three exploratory drilling projects in Nevada that were proposed near the state border, saying road use and other impacts for California could threaten habitat.

Lisa Belenky, a senior counsel for the group, faulted "years of voluntary conservation measures" as failing to stabilize sage grouse populations, underscoring that a lack of federal protection could mean more legal challenges at the state level.

Bridget DiCosmo, Washington

IN BRIEF

Shale Gas Output Still Rising

Gas production from seven major US shale plays is expected to rise by 466 million cubic feet per day in February to 96.66 billion cubic feet per day, the US Energy Information Administration (EIA) said in its latest *Drilling Productivity Report.*

The Haynesville Shale will see the biggest monthly gain at 145 MMcf/d, the EIA said, to 16.59 Bcf/d. Associated gas from the Permian Basin is seen increasing 109 MMcf/d to 21.72 Bcf/d, while Appalachia's output is expected to jump 93 MMcf/d to 35.37 Bcf/d. The agency foresees smaller gains in the Eagle Ford (46 MMcf/d), Bakken (33 MMcf/d), Anadarko (26 MMcf/d), and Nibobrara (14 MMcf/d).

The projections, based on the number of drilling rigs at work and their productivity, show US shale oil output rising about 76,000 barrels per day from the seven basins to average 9.375 million b/d in February.

Meanwhile, the uptick in stockpiles of drilled but uncompleted wells gained speed, rising by 40 in December, vs 22 in November and eight in October.

Chesapeake Sells Texas Assets

Chesapeake Energy said Wednesday it had agreed to sell part of its operations in South Texas to private equity-owned WildFire Energy for $1.43 billion in cash.

Chesapeake has been trying to heed calls by activist investor Kimmeridge Energy Management, which has pushed the Oklahoma City based company to move away from oil drilling in favor of lower-cost natural gas production.

"Today marks an important step on our path to exiting the Eagle Ford Shale as we focus our capital on the premium, rock, returns and runway of our Marcellus and Haynesville positions," Nick Dell'Osso, Chesapeake's CEO, said in a statement.

WildFire, owned by buyout firms Warburg Pincus and Kayne Anderson, is acquiring Chesapeake's Brazos Valley operations that are located in the eastern part of the Eagle Ford.

An initial payment of $1.2 billion will be supplemented by further annual contributions for the next four years.

Chesapeake's Eagle Ford position was marketed in three pieces, including Brazos. The company remains "actively engaged with other parties" regarding potential sales of the other two land packages, Dell'Osso said.

NextDecade Inks Japan Deal

US LNG developer NextDecade has secured its first Japanese buyer with Itochu Corp. signing a 15-year supply deal for 1 million tons of LNG annually from the proposed Rio Grande LNG export plant in Brownsville, Texas. The volumes will be indexed to Henry Hub on a f.o.b. basis.

The contract marks Itochu's first supply deal for US LNG.

It also keeps NextDecade on track to take a final investment decision on the first three trains at the five-train, 27 million tons/yr capacity LNG terminal during the current quarter.

With the Itochu contract, NextDecade has penned eight long-term supply deals for a total of 10.75 million tons of capacity. The first three trains have a total capacity of up to 17.61 million tons.

Interest in US LNG supplies has increased since Russia's invasion of Ukraine in early 2022, with Asian and European buyers competing for volumes.

However, Japanese firms have largely been absent from the flurry of deals for US LNG since last March.

New CEO Named at KMI

US pipeline behemoth Kinder Morgan (KMI) announced a slate of leadership changes Wednesday as CEO Steve Kean announced his intention to transition out of his current role after eight years at the helm.

KMI President Kim Dang will succeed Kean as CEO effective Aug. 1, while KMI Natural Gas Group President Tom Martin will step into Dang's role.

In a move announced last July, Midstream Gas Group President Sital Mody will move into Martin's post effective Feb. 1.

Between Feb. 1 and Aug. 1, Martin will serve as executive vice president, working with the office of the chairman. Kean will remain on KMI's board of directors.

Dang's tenure with KMI spans more than 20 years. Past roles include vice president of investor relations, treasurer and CFO. She has served on KMI's board of directors since 2017 and became KMI president in 2018.

Dang is "a collaborative and skillful decision maker and a great leader.

Her experience and many accomplishments over the years make her the obvious choice as the next CEO of Kinder Morgan," said Richard Kinder, the firm's executive chairman.

NATURAL GAS WEEK DATA ROUNDUP

NATURAL GAS FUTURES - Trading Dates: Jan 16-Jan 20

New York Mercantile Exchange (NYMEX) Henry Hub

	Monday		Tuesday		Wednesday		Thursday		Friday		Week's	Open
	Jan 16	Vol.	Jan 17	Vol.	Jan 18	Vol.	Jan 19	Vol.	Jan 20	Vol.	Low-High	Interest
Feb '23	--	--	3.586	143,310	3.311	119,853	3.275	99,670	3.174	--	3.091-3.789	46,101
Mar '23	--	--	3.253	97,107	3.111	85,806	3.124	77,459	3.036	--	2.985-3.440	252,861
Apr '23	--	--	3.218	48,853	3.086	45,431	3.114	37,708	3.030	--	2.985-3.372	97,731
May '23	--	--	3.283	30,715	3.154	23,599	3.191	27,211	3.112	--	3.066-3.421	104,544
Jun '23	--	--	3.421	15,183	3.300	13,065	3.336	13,913	3.259	--	3.219-3.565	45,567
Jul '23	--	--	3.551	14,632	3.440	12,596	3.483	14,492	3.413	--	3.375-3.689	46,987
Aug '23	--	--	3.584	10,287	3.479	9,169	3.522	7,986	3.459	--	3.423-3.716	34,376
Sep '23	--	--	3.528	8,550	3.426	10,519	3.475	9,516	3.413	--	3.379-3.648	59,284
Oct '23	--	--	3.597	17,776	3.494	20,425	3.549	16,253	3.493	--	3.455-3.714	70,924
Nov '23	--	--	3.995	4,255	3.902	5,290	3.969	4,402	3.932	--	3.863-4.098	29,990
Dec '23	--	--	4.423	3,476	4.342	3,007	4.402	3,072	4.365	--	4.279-4.520	35,384
Jan '24	--	--	4.670	7,379	4.595	8,571	4.649	6,239	4.610	--	4.535-4.776	53,606
Feb '24	--	--	4.516	2,283	4.438	2,405	4.497	2,013	4.472	--	4.385-4.616	18,521
12 Month Strip	**--**		**3.676**		**3.553**		**3.591**		**3.525**			
2024 Strip	--		4.028		3.969		3.952		3.928			
Total Volume		**--**		**416,537**		**375,421**		**640,618**		**--**		

GAS PRICE REPORT

($/MMBtu) The Week of	1/16/2023	APPA-LACHIA	CALIFORNIA North	CALIFORNIA South	LOUISIANA Gulf Coast Offshore	LOUISIANA Gulf Coast Onshore	LOUISIANA North	MID-CONT	MID-WEST	NEW ENG-LAND	NEW MEXICO	ROCKIES	SOUTH-EAST	TEXAS Central Onshore	TEXAS Gulf Coast Offshore	TEXAS West
Delivered to Pipeline	This Week	2.65	16.92	17.16	3.02	3.08	2.88	2.84	3.04	3.24	15.98	13.26	3.14	2.70	2.69	1.29
	Bid Week	4.02	40.24	42.01	4.32	4.97	4.38	6.73	6.63	12.50	31.79	48.02	5.41	4.11	4.61	5.15
Delivered to Utility	This Week	2.73	18.27	16.46	--	3.19	3.02	3.09	3.04	4.24	16.13	13.59	3.51	2.85	--	1.37
	Bid Week	4.11	50.16	58.31	--	5.12	4.52	6.84	6.11	20.47	31.94	48.35	5.35	4.26	--	5.23
Interstate Wellhead	This Week	2.54	--	--	2.95	3.01	2.81	2.74	--	--	15.81	13.14	2.99	2.62	2.62	1.22
	Bid Week	3.91	--	--	4.25	4.90	4.31	6.63	--	--	31.62	47.90	5.26	4.03	4.54	5.08
Intrastate Wellhead	This Week	--	--	17.19	2.95	3.01	2.80	2.72	--	--	--	13.11	--	2.64	2.63	1.22
	Bid Week	--	--	41.99	4.25	4.90	4.30	6.61	--	--	--	47.87	--	4.05	4.55	5.08

INTRASTATE WEEKLY SPOT PRICES - Trade Dates 1/17-1/20

Price Point	$/MMBtu	Chg.	High	Low	Avg. Daily Vol.	Avg. Daily Deals	Jan Bid Week
Oklahoma Intras	2.70	-0.10	2.76	2.50	63,314	9	5.86
West Texas Intras	--	--	--	--	--	--	--

PRICE OUTLOOK

	Composite Wellhead	Delivered to Pipeline	12-Month Strip Nymex
Jan 23, 2023	3.99	6.48	3.52
2023 Outlook	3.78	7.90	--

CANADIAN PRICE REPORT

($US/MMBtu and $Can/MMBtu)	ALBERTA AECO Hub	ALBERTA Empress Border	BRITISH COLUMBIA Total Province	BRITISH COLUMBIA Kingsgate Border	BRITISH COLUMBIA NW Sumas Border	MANITOBA Emerson Border	ONTARIO Dawn Hub	ONTARIO Niagara
January 20, 2023								
Delivered to Pipeline (US$)	2.67	2.71	15.15	3.28	16.00	3.09	3.16	--
Delivered to Pipeline (C$)	3.59	3.64	20.36	4.41	21.50	4.15	4.25	--
Wellhead (US$)	--	--	15.01	--	--	--	--	--
Wellhead (C$)	--	--	20.17	--	--	--	--	--
Dec 2022 Avg.								
Delivered to Pipeline (US$)	4.26	4.33	25.45	7.94	27.22	5.26	5.25	5.96
Delivered to Pipeline (C$)	5.79	5.88	34.62	10.79	37.02	7.14	7.14	8.13
Wellhead (US$)	--	--	25.31	--	--	--	--	--
Wellhead (C$)	--	--	34.43	--	--	--	--	--
2022 Avg.								
Delivered to Pipeline (US$)	3.95	4.72	7.70	4.82	8.04	5.51	6.08	6.02
Delivered to Pipeline (C$)	5.12	6.13	10.13	6.28	10.58	7.17	7.91	7.82
Wellhead (US$)	--	--	7.56	--	--	--	--	--
Wellhead (C$)	--	--	9.95	--	--	--	--	--

Note: Monetary conversions are done weekly. All prices represent volume-weighted averages for the most recent Monday-Sunday trading week.

NATURAL GAS WEEK DATA ROUNDUP

NORTH AMERICAN WEEKLY GAS STORAGE

(Billion Cubic Feet)

Region	Week Ending Jan 13	Week Ending Jan 6	% Full	1 Week Chg.	Year Ago	1 Yr Chg.	5 Yr Avg.	5 Yr Chg.
US								
East	662	700	60.2	(38)	678	(16)	658	4
Midwest	785	823	64.2	(38)	779	6	775	10
Mountain	147	153	31.1	(6)	152	(5)	154	(7)
Pacific	157	160	42.5	(3)	201	(44)	228	(71)
South Central	1,069	1,067	68.4	2	1,029	40	971	98
Total Lower 48	**2,820**	**2,902**	**59.6**	**(82)**	**2,839**	**(19)**	**2,786**	**34**
Canada								
East	203	215	72.1	(12)	234	(31)	209	(6)
West	325	333	66.4	(9)	343	(18)	362	(38)
Total Canada	**528**	**548**	**68.5**	**(21)**	**577**	**(49)**	**572**	**(44)**
Lower 48 & Canada								
Total North America	**3,348**	**3,450**	**60.9**	**(103)**	**3,417**	**(69)**	**3,358**	**(10)**

Sources: US-EIA. Canada-RBN Energy. Values in Bcf unless otherwise noted.

COMPARATIVE FUEL PRICES

(Cash Market) Jan 20, 2023

Natural Gas	$/MMBtu	Comparative Fuel	Fuel Price	MMBtu equivalent
Appalachia				
App Pool Dvld (util)	2.59	McCloskey CSX Coal	$137.90/ton	5.73
East Coast				
New York City Gate	3.36	Heating Oil No. 2*	317.43¢/gal	22.89
	--	Residual 0.30%	$91.11/bbl	14.49
	--	Residual 1.00%	$80.42/bbl	12.79
Gulf Coast				
TX Central Onshore	2.70	Heating Oil No. 2*	305.52¢/gal	22.03
	--	Residual 0.70%	$76.89/bbl	12.23
LA Gulf Coast Onshore	3.08	Residual 3.00%	$59.10/bbl	9.40
	--	WTI Cushing	$80.03/bbl	13.80

Notes: (1) Residual=Residual Fuel Oil, priced exclusive of taxes; (2) WTI=West Texas Intermediate crude oil; (3) % = % of sulfur content. *Average sulfur content = 0.2%-0.5%. *Sources: Gas: Natural Gas Week; all prices volume-weighted. Oil: The weekly average of The Oil Daily's cash price postings.*

SPOT ELECTRICITY TRADING

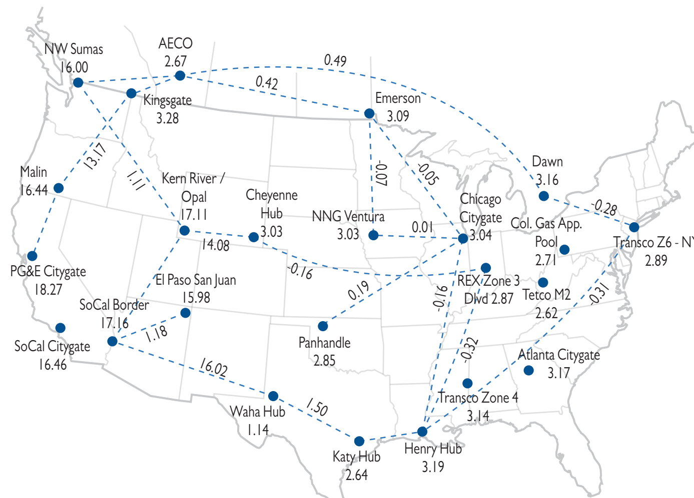
Trading Dates: 1/17-1/19, 2023

POINT	Avg. Price This Week	Avg. Price Last Week	Change	Year Ago	Month Ago
COB	$175.92	$155.55	$20.37	$39.25	$339.33
ERCOT	$35.39	$20.76	$14.64	$33.55	$38.01
Mid-Columbia	$167.85	$146.64	$21.21	$35.13	$308.63
NEPOOL	$48.58	$63.30	-$14.72	$180.63	$144.81
Palo Verde	$137.58	$144.35	-$6.77	$31.38	$277.00
PJM-West	$39.58	$48.13	-$8.54	$58.70	$103.56

Notes: (1) Prices in $/MWh. (2) Prices are for next day peak delivery.
Sources: Energy Intelligence and wire reports.

PRICES AND DIFFERENTIALS FOR MAJOR HUBS AND SELECTED CITY GATES

Jan 20, 2023 — (US$/MMBtu, Volume-Weighted)



Selected Daily Differentials

Differential	Jan 17	Jan 18	Jan 19	Jan 20
NY-HH	-0.46	-0.32	--	--
Chicago-HH	-0.31	-0.16	0.02	-0.05
CHIC-AECO	0.29	0.35	0.35	0.43
PG&E-AECO	19.22	17.41	12.45	12.66

BAKER HUGHES RIG COUNT

Week Ended Jan 20, 2023

Region	Current Week	Previous Week	Year Ago
Total US	771	775	604
Land	753	754	584
Inland Waters	2	2	2
Offshore	16	19	18
Gulf of Mexico	16	19	18
Total Canada	241	227	212
US Rigs Exploring for			
Oil	613	623	491
Gas	156	150	113
Unspecified	2	2	0

US Gas Rig Count