RESHUFFLING

THE DECK

High Stakes for Natural Gas & The World is All-In

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U.S. PRODUCTION

NGI | A Special Edition of *NGI's All News Access*

Entering 2023, the natural gas industry appears to be holding all the cards as the fuel continues to evolve as a global commodity. The ongoing war in Ukraine and the resulting cut in Russian natural gas supplies have sent Europe scrambling for alternatives, putting a premium on LNG cargoes from the United States and beyond.

In *Reshuffling the Deck*, Natural Gas Intelligence's roster of veteran Thought Leaders explores pressing questions facing the natural gas market, pivotal events, as well as the challenges and opportunities that may arise for the industry in the new year.

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RESHUFFLING THE DECK: AN NGI SPECIAL EDITION

Volatility Laces 2023 Natural Gas Price Outlook Amid Robust Production, Demand Uncertainty

U.S. natural gas prices are off to a rocky start in 2023, and analysts are braced for a choppy ride ahead amid expectations for strong production levels, infrastructure constraints and forecasts for relatively mild weather during the heart of winter.

Limits on American exporters' collective ability to meet global needs add another layer of uncertainty – given both the *protracted Freeport LNG outage* and a dearth of new liquefied natural gas facilities this year.

"It's looking really volatile here to start the year, obviously," Marex North America LLC's Steve Blair, senior account executive, told NGI. "We have a lot of factors at play – production, LNG – but ultimately weather will rule, as it almost always does.

"It's early in the winter. If we get more Arctic blasts, the direction of prices could change quickly," Blair continued. "If we don't, and production holds up, we could see new tests to the downside."

To be sure, robust early-winter heating demand across the Lower 48 intersected with intensifying calls for American LNG late in 2022 from both Asia and Europe. Harsh weather in the Rocky Mountains, North Dakota and Midcontinent caused wellhead freeze-offs and temporarily dropped production into the low 90s Bcf/d in December, bolstering prices.

Natural gas futures held comfortably above $5.000/MMBtu late last year and NGI's Spot Gas *National Avg.* surged to nearly $20 – boosted in part by widespread freezing weather in typically mild winter climates such as California. By the first week of the new year, however, temperatures warmed over large swaths of the country – with more expected through most of January – and *production rebounded* to around 101 Bcf/d, near record levels.

As the first week of January trading culminated, futures had flopped well below the $4 handle – and far from the highs last summer near $10 — while cash prices fell to near $5. The exceptional price volatility could define trading in the months ahead, at least until the extent of summer heat becomes known.

February fixed prices tumbled an average of $1.070 across the country, while March dropped 46.0 cents on average, according to *NGI's Forward Look*. Smaller losses were posted for the summer (April-October) and winter 2023-2024 (November-March) strips.

Production Powers Up

While characteristically uneven in the winter because of freeze-offs, U.S. natural gas production often topped 100 Bcf/d late last year – hitting record levels above 102 Bcf/d at points. Output averaged close to the century mark for the fourth quarter, according to the Energy information Administration. Production again exceeded the 100 Bcf/d threshold early in 2023.

Output climbed with robust demand throughout 2022 and expectations for long-term growth in export volumes. With associated gas production in the Permian Basin strong alongside oil output reaching a pandemic-era high last year – and holding close it early in 2023 – East Daley Analytics estimated that domestic production would rise by up to 5 Bcf/d over the course of this year and reach 104.5 Bcf/d late in 2023.

East Daley's Robert Wilson, vice president of analytics, told NGI that producers already have set in motion the momentum necessary for ongoing growth this year, and the extra gas will be needed – but perhaps not right away.

Why?

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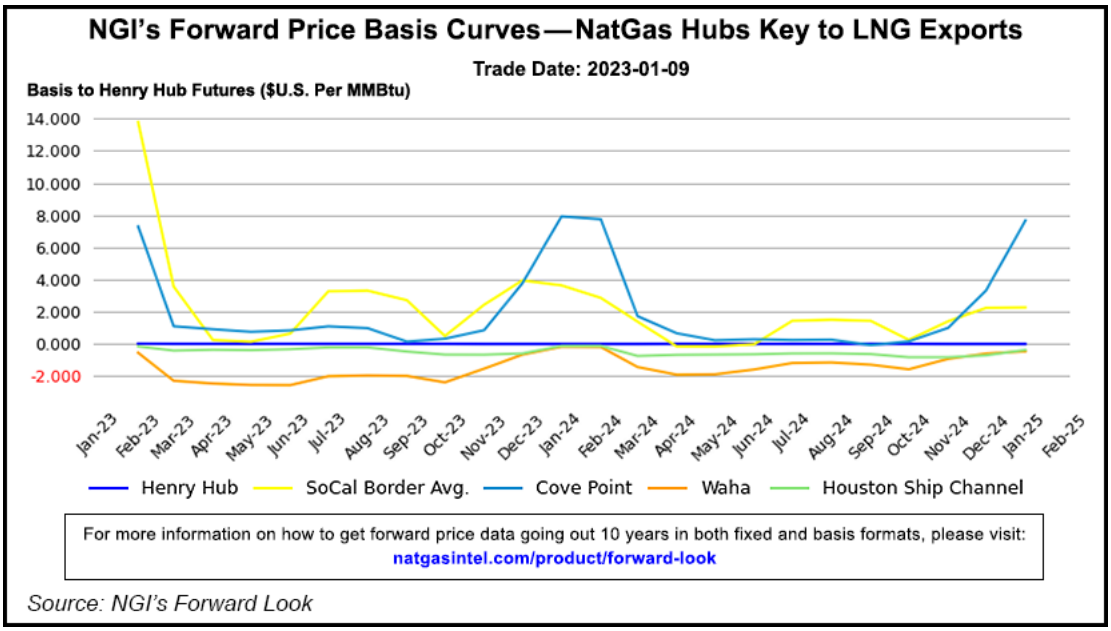

Source: NGI's Forward Look

E&Ps Preaching Discipline Amid Softer Natural Gas Price Forecast, Prioritizing Energy Security Over ESG Transition

The U.S. natural gas and oil sector is likely to achieve moderate growth this year, preferring to hoard cash, reduce debt and continue investor payouts while awaiting stronger commodity prices, according to a bevy of energy analysts and executives.

E&P executives are surveyed twice a year by Evercore ISI to determine the level of capital expenditures (capex) and activity, which often are revised. Respondents indicated that global spending should continue to rise, up by 14% from 2022. However, it's down from the 2022 growth rate, when capital spending jumped 20% overall from 2021.

The upstream sector should have "another strong year," but commodity prices and free cash flow (FCF) are unlikely to match 2022 levels, according to Moody's Investors Service. Mizuho Securities USA LLC is forecasting the U.S. gas macro also to be "challenged until further LNG capacity comes online in late 2024."

The mantra across the board is once again FCF repeating the capital discipline demonstrated in 2022 and 2021. E&Ps no longer want to be caught flat-footed by unforeseen events that jolt the commodity markets and send them scrambling.

"Most producers will try to follow the same playbook in 2023 that yielded strong financial results in 2022," said Moody's senior credit analyst Sajjad Alam. "Companies will look to exercise capital discipline, invest strategically and maximize free cash flow" to improve their balance sheets. In addition, they want to "maintain high levels of shareholder distributions and better position their asset portfolios and production levels for long-term energy transition risks."

Higher Payout Ratios In Onshore

"Don't give up on the U.S. onshore just yet," said Mizuho analyst Nitin Kumar. "While cash returns may be lower year/year in 2023 due to weaker commodity prices, payout ratios will be higher."

Shale well productivity "may have plateaued," but the decline last year in productivity "can be attributed to private operators drilling in (presumably) lower quality assets."

FCF this year, though, may trump all. Since the sharp commodity price downturn in late 2015 and into 2016, E&Ps today are a disciplined lot, more apt to reward shareholders than incur debt to add to their resources.

"While we suspect E&P management teams are unlikely to walk back on current cash return commitments in the near term, we expect investors – especially those

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with longer investment horizons – to focus on the sustainability of value creation rather than the immediacy of it," Kumar said.

Energy security today also is a priority.

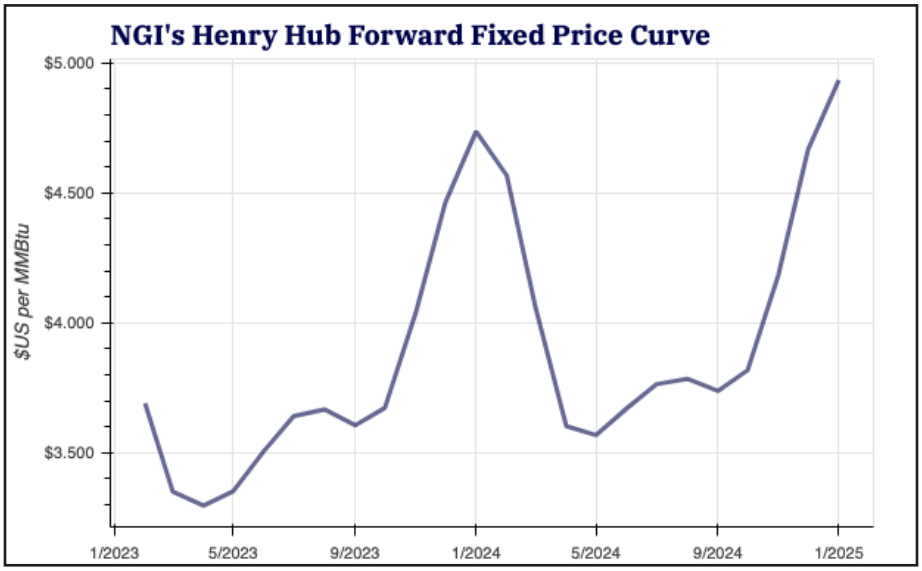
It took "center stage for many nations following Russia's invasion of Ukraine," Moody's Alam said. Evercore ISI managing director James West agreed.

"We are now in a world where energy security has taken center stage and with that, the need to rebuild production capacity after years of underinvestment," West said. "North America will not be able to step in as the swing producer."

'Energy Trilemma' In Focus

Wood Mackenzie analysts said the Russia-Ukraine war threw the "energy trilemma into sharp focus. Oil and gas are part of the solution to finding a balance between security, affordability and sustainability. The immediate call on the industry is for more of both, as fast as possible.

"Yet the longer-term desire remains for an accelerated shift away from hydrocarbons. It's the same, somewhat contradictory, challenge that oil and gas companies have wrestled with for the past five years. The crisis of 2022 has generated new opportunities but also amplified the challenge and exacerbated the associated risks."



Last year had begun with high expectations across the energy sector to enact environmental, social and governance (ESG) frameworks. ESG is still on the table, but don't expect to hear as much about it in the coming months by traditional E&Ps. Energy security demands should continue to usurp ESG, according to Moody's John Thieroff, senior credit officer.

"The energy sector faces a number of conflicting energy transition pressures for 2023 and beyond," he said. Producing fewer fossil fuels to decarbonize remains a priority to limit the rise in global temperatures. However, sanctions on Russia's oil and natural gas exports "removed a significant source of supply from the market, and risks will persist about energy security, affordability and maintaining high levels of reliable production.

"Energy security concerns in 2023, particularly in Europe, add to the burden of accelerating the decarbonization effort," Thieroff said. "While policy risk will remain high for the sector in 2023, energy security concerns will be on equal footing with energy transition efforts.

"A large majority of spending will be directed toward traditional oil and gas operations, with a still small but growing share directed toward new energy businesses. Europe's emergent need for LNG amid the displacement of Russian gas will drive considerable investment over the next several years, including a push to install more multi-decade-lived assets and further supporting natural gas's incumbency."

To that end, E&Ps should continue to shuffle their portfolios, according to Wood Mackenzie's team.

"Oil and gas operators will quietly maintain their focus on investing in security of supply while showcasing decarbonization progress," analysts said. "Portfolio reconfiguration along more resilient and sustainable resource themes will continue, while a handful of advantaged operators will make inroads on developing 'carbon capture as a service' business models."

Supply Chain, Labor Challenges Persist

Some hurdles remain to be jumped.

"Tight land drilling and pressure pumping markets, supply chain and labor challenges and continued discipline from public independents will cause North American growth to moderate," Evercore's West said. E&Ps may face challenges in finding "high quality U.S. land rig and pressure pumping spreads as high utilization levels and no incremental supply keeps markets very tight…"

In addition, the natural gas-weighted E&Ps are facing a dearth of liquefied natural gas export startups (unlikely before 2024) and potential Lower 48 pipeline bottlenecks.

Lower natural gas prices also pose a roadblock to accelerate drilling, according to Tudor, Pickering, Holt & Co. (TPH). Analyst Matt Murphy and his team have a "negative bias" on natural gas pricing into the summer, which could lead to rigs coming down and slow activity.

U.S. onshore natural gas rigs this year are forecast to average 117 across the most prolific gas formations, the Haynesville Shale and Appalachian Basin, according to TPH modeling.

Baker Hughes Co.'s U.S. natural gas rig count for the week ending Jan. 6 fell by four from a week earlier to 152. The *Haynesville by itself posted a three-rig decline* week/week.

FCF, commodity price swings and weather aside, E&Ps and oilfield services companies are

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facing some of the same issues they've felt for years. Labor is one.

"Automation cannot drill wells, move rigs and build locations," an E&P executive said in a *survey conducted in December by the Federal Reserve Bank of Dallas*. "The government can remove all regulations and timetables, and the amount of increase in activity would not be affected by more than 10%."

Employment issues are a "significant obstacle to growth," another executive said. "We cannot hire the talent we need. Our competitors' employment packages are so good at attracting talent that offers have evolved to a level I have never seen in the 40 years I've been in the business."

What may not cause heartburn this year are regulatory issues. Following November's midterm elections, Congress now is split, with Democrats controlling the Senate and Republicans, the House.

However, "the uncertainty of China (Covid-19) and Russia (Ukraine) is creating a great deal of demand uncertainty," an energy executive said. "Ultimately, global demand for fossil fuels will likely outstrip available supply due to nearly eight years of underinvestment, combined with still-constrained capital availability to the industry.

"The only question is when this violent swing to undersupply will occur. Previously, I thought it could happen by the end of 2022. Today, it seems more likely in the second half of 2023." ■

Carolyn Davis

Emerging U.S. Pipeline Bottlenecks Cast Shadow on Otherwise Positive Long-Term Outlook for Natural Gas

As the United States works toward casting a wider net on the global natural gas market via exports, key domestic markets could be turned upside down in 2023 as midstream bottlenecks leave gas stranded in producing basins.

LNG developers on the Gulf Coast are in a race to boost liquefied natural gas exports to capitalize on rising demand in Europe and Asia. Some projects are *under construction* and could begin operations in 2024. A *handful of others* could be sanctioned this year.

East Daley Analytics Inc. projects U.S. liquefaction capacity could swell to nearly 30 Bcf/d by 2030. That's up from around 13 Bcf/d in 2022. *Gas companies* up and down the value chain also see continued momentum for LNG.

Producers have taken notice of the export growth potential. As head of one of the largest North American independents, *Ovintiv Inc.* CEO Brendan McCracken told investors on the 3Q2022 earnings call that "what we see unfolding is a call on North American gas supply and global LNG demand, whether it's in Europe or Asia or other parts of the developing world…That's durable pricing that we see unfolding over decades…"

U.S. regulators share a similarly optimistic view. The Energy Information Administration sees export demand growth driving an increase in *natural gas production* this year. The agency expects output to average 100.4 Bcf/d in 2023.

At the heart of the increased supply is rising output in the prolific Permian Basin of West Texas and southeastern New Mexico, and the Haynesville Shale in East Texas and southwestern Louisiana.

The problem is, pipelines in the Permian and Haynesville are nearly tapped out and could fill completely this summer. That means any additional production hitting the market this year is likely to struggle to make its way downstream. It's a sore spot for the midstream sector, one that isn't likely to be remedied anytime soon.

For the Permian in particular, East Daley's Robert Wilson, vice president of analytics, said he expects supply growth to fill basin takeaway sometime in the first quarter of 2023.

West Texas Woes

The lack of takeaway out of the Permian has been an issue before.

In 2019, swelling gas output filled pipelines, and the market awaited Kinder Morgan Inc.'s Gulf Coast Express (GCX). The 2.0 Bcf/d conduit was a boon for producers, which sometimes were forced to pay customers to take their gas before GCX *began service in the fall* of 2019. Gas prices at the Waha Hub in West Texas at one point fell to negative $9.00/MMBtu.

Pipeline space grew hard to come by the following year, with prices tumbling to negative $10 as producers paid to get gas off their hands. Kinder then brought online the 2.1 Bcf/d *Permian Highway Pipeline* (PHP).

WhiteWater Midstream LLC and its partners brought online the *Whistler Pipeline* in the summer of 2021. However, Whistler began operations in a far different landscape than its predecessors. After Covid-19 upended the energy industry and decimated demand, Whistler started flowing gas when there was pipeline capacity to spare in the Permian. That didn't last long, though.

Permian production was reported to be close to a record 16.5 Bcf/d in December. Though estimates vary, more growth is expected.

East Daley's analyst team sees a Permian exit-to-exit growth rate of 1.8-1.9 Bcf/d this year. Wood Mackenzie expects production out of the basin climbing only around 0.5 Bcf/d in 2023. Aegis Hedging Solutions LLC, meanwhile, expects growth somewhere in the middle of that range.

What's preventing analysts from providing clearer guidance? Tightening egress and uncertainty over when more pipeline capacity may hit the market.

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Projects In The Works

There are some projects underway in West Texas to add takeaway. Kinder is planning to add compression along PHP. The midstreamer sanctioned the *550 MMcf/d expansion project* last June and is targeting start-up in November.

An open season was launched last May to gauge interest in boosting capacity on GCX as well, but few details have been provided. Notably, PHP's planned expansion is not quite as big as the 650 MMcf/d previously outlined in Kinder's open season.

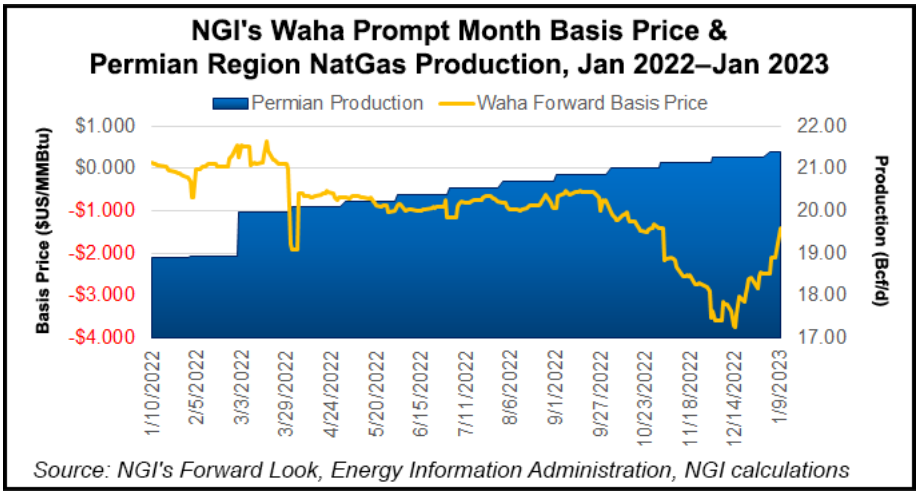
WhiteWater, meanwhile, is forging ahead with plans to expand Whistler's mainline capacity to about 2.5 Bcf/d with the addition of three compressor stations. Those are expected to be in service by September.

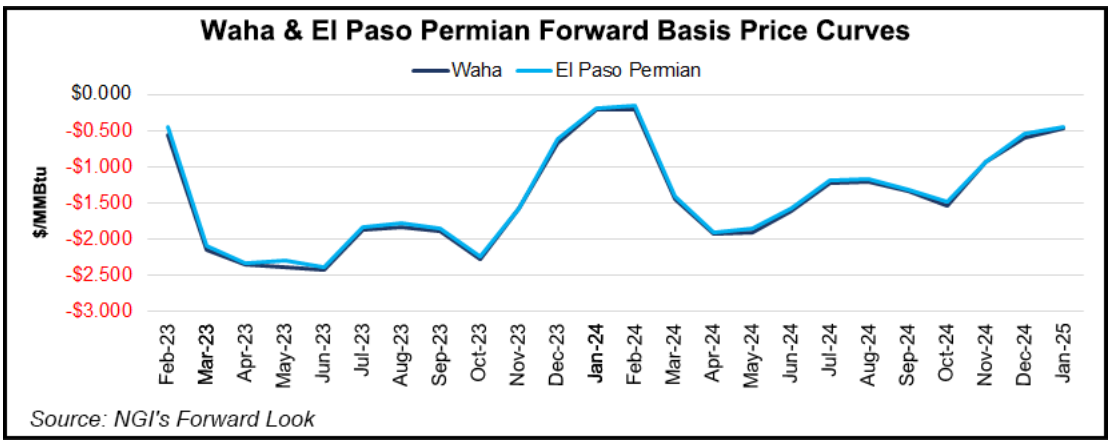
"We need everything online as planned," East Daley's Ajay Bakshani, senior capital markets analyst, told NGI. Even then, those pipelines are likely to fill quickly, he said. No significant alleviation in constraints is expected until 2024, when WhiteWater's *Matterhorn Express* greenfield project is due online, according to the analyst.

"It's not a great outlook for Permian gas overall," Bakshani said. "We're *cutting rigs back* a decent amount, but we're still seeing growth. Matterhorn provides some breathing room, but we expect constraints to materialize again in late 2025 or early 2026."

Energy Transfer LP has discussed building the *Warrior Pipeline*, which could move 1.5-2.0 Bcf/d from the Permian toward Dallas, where it would access existing pipes to the Gulf Coast. Management was evaluating the project last summer, but *expressed optimism* that it could bring the project to a positive final investment decision.

"I wouldn't be surprised to see additional development," Bakshani said. "Those conversations will be happening now."





Situation Worse Before It's Better?

Until then, things could get ugly in the Permian.

Wood Mackenzie's Ben Chu, head of Trading Analytics and Proprietary Data, explained that it's not that the market is awaiting new pipeline capacity out of the Permian. What's making matters worse is that gas flows on existing pipelines are being restricted because of maintenance or otherwise.

Chu said Kinder has reduced capacity on GCX to 1.855 Bcf/d since Dec. 28 because of repairs at the Devil's River Compressor Station. Meanwhile, PHP's throughput has been restricted to 1.8 Bcf/d since Dec. 17.

"Interestingly, both outages were related to compressors in recently installed Kinder Morgan pipelines," Chu said.

It's its last update in late December on GCX, Kinder said, "Due to unforeseen circumstances, it is necessary to keep the reduction in place until further notice."

Similarly, Kinder said the PHP restrictions would likely continue for several weeks after it was determined that one of the units at the Coyanosa Compressor Station would have to be evaluated and repaired following an inspection.

There's also Kinder's El Paso Natural Gas, which shut its Line 2000 in August 2021 following a *deadly blast in Arizona*. That outage took 450-500 MMcf/d of pipeline capacity out of the market.

"The important thing to note though is that the Line 2000 explosion was due to stress-related corrosion cracks eating away at the steel. There's nothing special about the spot that exploded, and El Paso is an old line," Chu said. "Timing is still an unknown, and further findings on an old pipe is just a steadily growing risk over time."

Given Wood Mackenzie's modest Permian production growth estimate, Chu said one could argue the ...cont'd pg. 6

basin would have enough takeaway if Line 2000, GCX and PHP were to return to service. The planned expansions on Whistler and PHP, meanwhile, should help accommodate any Permian growth.

That said, when West Coast demand slows down in the shoulder seasons, all bets are off, according to Chu. The demand sink can only take so much, and California's flexibility in storage is down this year too.

"So there's definitely risk for 2023, and perhaps a higher degree of it going into the fall shoulder season due to both West Coast seasonal demand and any construction timing risk while production steadily grows. Any unexpected outages at that point in time could be highly impactful," he said.

If it weren't for *natural gas flaring*, Chu said, Permian gas would need to price anywhere from negative $6.00 to negative $40 in order for oil and natural gas liquids producers to fully offset their uplift and still cover operating costs. Waha has already hit negative *$10 again this year*.

Rough In Haynesville Too

The Haynesville also is growing considerably, according to Bakshani. He noted the myriad of *offtake agreements* signed between U.S. LNG developers and global customers, especially in the wake of Russia's invasion of Ukraine.

"Clearly, the market is very excited," he said. "The overall attitude toward natural gas is improving with the world realizing how much we need." However, most of the growth in LNG demand is not expected until 2025 and beyond. Until then, the market has to be careful in managing that risk, according to Bakshani. "We view the market being oversupplied in 2023."

Chu agreed.

While Energy Transfer last month started service on the 1.65 Bcf/d *Gulf Run Pipeline* in Louisiana, gas near the Texas Gulf Coast/South Louisiana border is struggling to find an outlet because *Freeport LNG* is still offline following a June explosion, according to Chu. This has left 2 Bcf/d of additional gas to be cleared from Texas markets.

"Pipes from Texas to Louisiana are effectively full, whether at the border or a little further downstream, so there's near-term risk of clearing more Haynesville gas through Gulf Run until Freeport comes back online," Chu said.

Further into the year however, Texas production should continue to grow, according to Chu. At the same time, pipes from the Permian to South Texas would put more gas into the area.

"Eagle Ford is also still growing, so further along in the year, there is risk of more gas-on-gas competition as any *Haynesville gas* pointed to Gillis Hub or near the Texas/Louisiana border will need to compete with Texas molecules."

There are wildcards in the mix. Summer weather should be a key indicator of how much gas is replenished in storage. So far this winter, withdrawals have been light and an

end-of-summer storage inventory level well above 4 Tcf is not out of the question, according to Chu.

"There's a good chance Texas storage will have a little less flexibility in the fall shoulder season than normal," he said.

There are more projects underway to help alleviate the pipeline capacity issues in Louisiana. Enterprise Products Partners LP is targeting the second quarter to bring online its 400 MMcf/d *Acadian Expansion II*. DT Midstream Inc. expects its 300 MMcf/d *Louisiana Energy Access Project (LEAP) Expansion Phase 1* to begin service in late 2023.

Still, Chu, Bakshani and Wells Fargo analysts see *Haynesville takeaway remaining tight* absent more capacity additions. There are several in the works, but those aren't slated for in-service for another two years or more.

MVP Fight Continues

The solution to the Northeast's lack of takeaway, meanwhile, has fallen to producers.

Years after major pipeline projects like *PennEast Pipeline*, *Constitution Pipeline* and *Atlantic Coast* were scrapped, Appalachia-focused producers have had to operate mostly in maintenance mode. By and large, flat production profiles have been adopted by most major producers in the basin.

EQT Corp., for example, curbed production in the third quarter of 2022 as it faced supply chain issues, midstream constraints and adverse weather. The nation's largest gas producer doesn't expect to be back on track until the middle of the year. Appalachian stalwarts *Range Resources Corp.* and *Antero Resources Corp.* also reported midstream issues last year.

With a hostile regulatory environment contributing at least in part to the scrapping of several large pipeline projects in recent years, *Mountain Valley Pipeline* (MVP) stands alone in potentially bringing an incremental 2 Bcf/d of takeaway capacity to Appalachia. Total work on the project is nearly 94% complete, but the pipeline has faced staunch opposition that has resulted in multiple delays – and uncertainty for the market.

MVP, a joint venture of EQM Midstream Partners LP, NextEra Capital Holdings Inc., Con Edison Transmission Inc., WGL Midstream, and RGC Midstream LLC, has said it remains "committed to working diligently with federal and state regulators to secure the necessary permits to safely and responsibly finish construction, and we remain committed to bringing" the project "into service in the second half of 2023." ■

Leticia Gonzales

Henry Hub Seen Recovering Later This Month as EIA Models $5/MMBtu for 1Q2023

Natural gas prices have staggered into the new year, but Henry Hub is set to recover to average near $5/MMBtu for the first quarter of 2023, according to updated projections from the U.S. Energy Information Administration (EIA).

Despite dipping below $4 in early 2023, spot prices at Henry Hub will climb back above the $5 mark for late January into early February, the agency said in the January edition of its *Short-Term Energy Outlook* (STEO), published Tuesday.

The agency said it forecasts falling temperatures later this winter, and it also pointed to the scheduled partial restart of operations at the Freeport LNG terminal this month as a source of upward pressure on prices.

"Based on the most recent press release from Freeport LNG, we expect the facility to resume partial operations in January" and push U.S. liquefied natural gas export levels higher, researchers said. "However, any additional delays to the restart of Freeport, which was originally scheduled to restart partial operations in November, will contribute to downward pressure on prices in the near term."

EIA said it expects U.S. residential/commercial demand to average around 46 Bcf/d in January, lighter than the prior five-year average on mild temperatures to start the month.

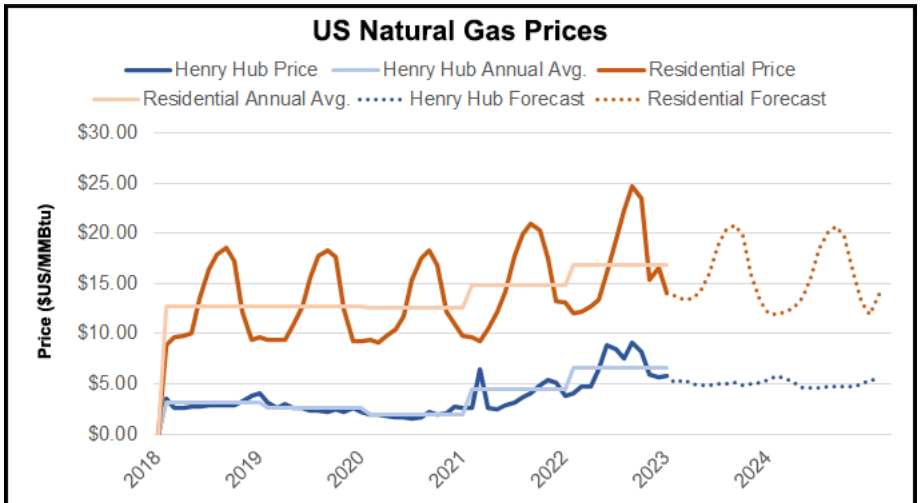
Demand is set to average 43 Bcf/d in February, also below the prior five-year average, EIA said. The agency cited forecasts from the National Oceanic and Atmospheric Administration that "indicate above normal temperatures for February in the eastern part of the United States."

Looking beyond the winter heating season, EIA predicted average Henry Hub prices near $5 for the final three quarters of 2023. A combination of higher domestic natural gas production, flat LNG export levels and declining domestic consumption from power generation and industrial demand sources will "limit upward pressure" on prices this year, researchers said.

"Despite our expectation that new LNG export facilities and expansion projects will come online in 2024, we expect natural gas prices to be relatively flat — with the possibility of lower prices — due to continued increases in U.S. natural gas production," EIA said.

Production out of the Permian Basin and the Haynesville Shale will grow as new pipeline expansions come online this year and next, according to the agency. ■

Jeremiah Shelor



Source: NGI's Bidweek Survey, NGI's Forward Look, NGI calculations, EIA January 2023 Short-Term Energy Outlook

North American E&P Spend Seen Moderating, but Still Up by Double-Digits in 2023

Only a few U.S.-based exploration and production (E&P) companies have provided formal capital spending plans for 2023, but expenditures overall are forecast to decelerate from a year ago.

E&P executives are *surveyed twice a year by Evercore ISI* to determine the level of capital expenditures (capex) and activity, which often are revised. Respondents indicated that global spending should continue to rise, up by 14% from 2022. However, it's down from 2022, when capital spending jumped 20% overall from 2021.

North America, however, is still seen with a solid gain in capex for 2023. "While we forecast growth to decelerate in both North America and internationally, North America's impressive 18% end-of-year growth follows a near record 44% in 2022," said Evercore managing director James West.

U.S. E&P executives surveyed in late December were setting their capex for 2023 using an average oil price forecast of $78/bbl West Texas Intermediate (WTI) oil and $5.10/MMBtu Henry Hub (HH) natural gas.

"Average oil and gas prices of $125 WTI and $7.70 HH were cited for budgets to revise higher while $62 WTI and $3.25 HH were cited for budgets to revise lower," West said. "With energy security, surety of supply and production capacity additions key drivers for a cyclical recovery in global E&P spending, we believe there is only moderate risk to our initial estimates for 2023 growth rates in the 15-20% range for all the key operating regions."

U.S. natural gas futures *averaged above $5.00 late last year*, while NGI's Spot Gas *National Avg.* surged to nearly $20 as freezing weather hit typically mild winter climates, including in California. *...cont'd pg. 8*

Although natural gas prices staggered into the new year, *HH is set to recover to average near $5.00 through March*, according to updated projections from the U.S. Energy Information Administration. The projections were published in the January edition of its *Short-Term Energy Outlook*.

Chevron, ExxonMobil Eye Americas

U.S.-based supermajors Chevron Corp. and ExxonMobil issued their capex plans in December. ExxonMobil's *2023 capital budget of $23-25 billion* has almost three-quarters directed to developments in Brazil, Guyana, the Permian Basin and for LNG projects. Through the first nine months of 2022, the supermajor had spent about $15 billion, implying full-year capex of around $20 billion-plus.

Chevron, which set a $17 billion budget this year, plans to *spend nearly $8 billion for U.S. upstream projects,* up 25% year/year. About one-half of the capex, $4 billion, is budgeted for the Permian, up by one-third.

Chevron's capex plan, said CEO Mike Wirth, is "in line with prior guidance despite inflation. We're winning back investors with capital efficient growth, a strong balance sheet and more cash returned to shareholders."

The Evercore survey indicated that North American E&P capex "should increase by 18% in 2023, rising 6% above 2017 and within 5% of 2019 levels," West noted.

This year may approach pre-Covid levels, he said.

"Building on strong growth in 2022, we project North American E&P spending to increase by 18% in 2023 to within 7% of pre-Covid levels. The U.S. should lead again with spending up 19% in 2023 while Canada moderates at 10.5%."

Independents and private operators account for more than 70% of regional capex in North America.

"While privates were faster to increase capex post-Covid, the publicly traded independents shored up their balance sheets and prioritized returning cash to shareholders," West noted. "We believe this trend could be reversing, with privates becoming more fiscally minded as service cost inflation begins to rise."

The private E&Ps account for around 20% of Evercore's U.S. capex estimate – but 6% of the rig count. That suggests that overall U.S. spending could be larger than Evercore's estimate.

"Directionally our sample of private operators increased U.S. capex by 67% in 2022, accelerating from 56% in our mid-year survey and topping overall growth of 48% from independents…"

When all is said and done, if oil and natural gas prices were to hold at current levels, "we believe 2023 North American capex is at risk of slipping below our initial estimates," West said. "At the current 17% rate, it would take five additional years (end-2028) for North American capex to recover to its historical 2014 peak."

Exploration Spending Up

Nearly 25% of Evercore's survey respondents plan to increase exploration spending in 2023, while around 10% expect to make reductions.

"This is similar to initial plans for 2022, with a two-year streak of higher planned exploration spending slipping slightly from 2.7-2.5 times for 2023," the survey noted

"The economics of exploration are viewed by our survey respondents as excellent or good by a majority 63% in the U.S. but only 22% in Canada and 33% international, generally inline from 62%, 40% and 25%, respectively, one year ago."

If commodity prices were to stage a sharp recovery this year, executives would remain wary. For one thing, oilfield services costs continue to rise. "Service availability" was the most cited potential bottleneck in the survey for E&Ps to miss their 2023 production targets.

"Higher service pricing that materialized in 2022 is expected to broaden in 2023, with pricing increases anticipated for fracturing/stimulation, drilling and completion equipment," West said. "Operators called out subsurface completion and production, and enhanced oil recovery, as areas in need of greater technology innovation…"

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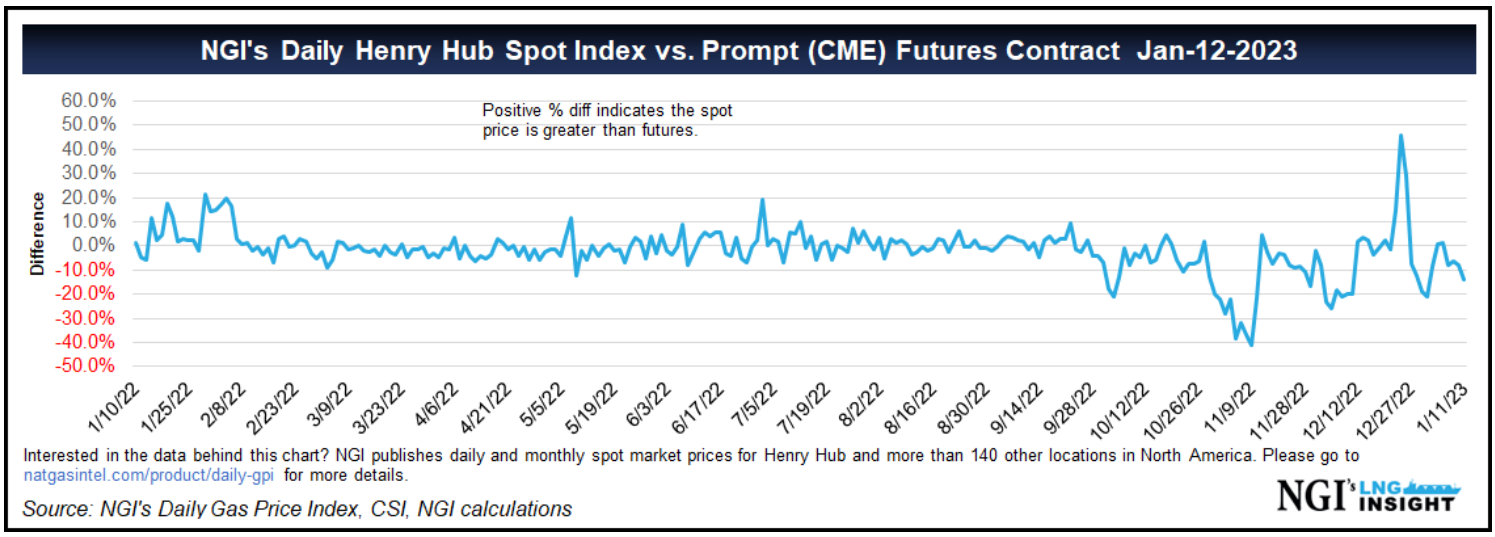

A "small but growing group of E&Ps are more likely to test and adopt new technologies and pay a bit more for service and technologies that lower carbon emission."

Overall capex may be set to rise for North American E&Ps, but the gains may be mostly by the oil-weighted E&Ps – not the natural gas-weighted companies.

"Drillbit capital allocation has been top of mind with investors," said analyst Matt Portillo of Tudor, Pickering, Holt & Co. (TPH). Recent conversations with the gas-weighted E&P executives "suggest that there so far is little movement on capital allocation plans in 2023."

E&Ps working in the Appalachian Basin plan to "stick to maintenance capital plans," and have more "growth aspirations" trained on the Haynesville Shale.

However, Portillo and the TPH team do not think the market needs incremental gas production growth. Ultimately, the market may "need to force the curve lower to push rigs out of the market," he said. Executives "continue to see $3/MMBtu or less on strip, with duration, as a notable inflection point on capital."

Mizuho Securities USA LLC analyst Nitin Kumar noted that U.S. E&P capex had declined overall for two years, primarily because of lower spending by U.S. onshore producers.

"Capex is in great part determined by the oil price environment," Kumar said. Declines in prices, price volatility and a renewed vow to remain disciplined in spending have "led to lower investment plans that keep supply limited, therefore limiting the decline in oil prices (barring a collapse in demand)."

It still comes back to capital discipline and cash flow, according to Evercore.

"For the seventh straight year and eighth time in nine years, cash flow leads as the key determinant of E&P spending," the survey noted. "A new record 88% of our survey respondents cited cash flow as a key driver of E&P spending, up from 77% in our 2022 survey and the previous record of 80% in our 2015 survey."

Cash flow has ranked No. 1 or No. 2 as the leading determinant of E&P spending in all but four of the past 24 years in Evercore's survey history. The price of oil has ranked Nos. 1, 2 or 3 since 2009.

"Natural gas prices reigned supreme from 2000 to 2010 with the onset of the gas shale revolution but have slipped in recent years to a lowly fifth place," the survey noted. "Stronger balance sheets appear to be less of a gating pressure on E&P spending plans."

Investor demands, combined with challenging market conditions, have forced E&P operators since 2018 to become more capital-disciplined.

"For 2023, strong capital discipline is extended again with another 88% of our survey respondents again planning to spend within cash flow versus only 13% that plan to draw down cash from elsewhere to fund capex," the Evercore team noted. "A record 67% plan to generate excess cash, likely for paying down debt and returning cash to stakeholders." ■

Carolyn Davis

What's Ahead for Natural Gas Consumers in 2023?

U.S. electricity consumption is forecast to decline this year and only marginally increase in 2024, but natural gas consumption gains may be seen amid rising industrial demand. Regulatory action also could be stymied, according to industry advocates.

The American Gas Association (AGA) pointed out the positives on Thursday. Incoming Chair Suzanne Sitherwood, who is CEO of Spire Inc. in St. Louis, outlined her vision. She was joined by AGA CEO Karen Harbert.

"What the natural gas industry does reaches far beyond the pipe in the ground," Sitherwood said. "The homes and businesses – and the communities – we serve are the heart of this industry.

"Nearly 187 million Americans use natural gas because it is affordable, reliable, safe and essential to achieving a cleaner future for our nation. Natural gas is the best way to deliver affordability and reliability today and emissions reductions tomorrow."

Spire delivers natural gas to more than 1.7 million homes and businesses in Alabama, Mississippi and Missouri.

Harbert called for an inclusive approach to the nation's climate challenge.

"The most practical, realistic way to achieve a sustainable future where energy is clean, as well as safe, reliable and affordable, is to develop a plan that includes natural gas and the infrastructure that transports it," Harbert said.

In a study titled "Net-Zero Emissions Opportunities for Gas Utilities," AGA presented a "national-level approach that leverages the unique advantages of gas technologies and distribution infrastructure," Harbert said.

To that end, AGA this year is planning a series to examine the importance of natural gas in various industries.

Electricity Generation Slightly Slumping

In its *latest Short-Term Energy Outlook* (STEO), the U.S. Energy Information Administration (EIA) said electricity consumption should decline by 1% in 2023 and then grow by slightly more than 1% in 2024.

Declining electricity consumption may be the result of reduced demand in the residential sector, EIA noted. Declining retail sales are forecast from an expected milder summer ahead, "with about 10% fewer cooling degree days." There's also expected to be a "sharp decline in growth" in U.S. housing.

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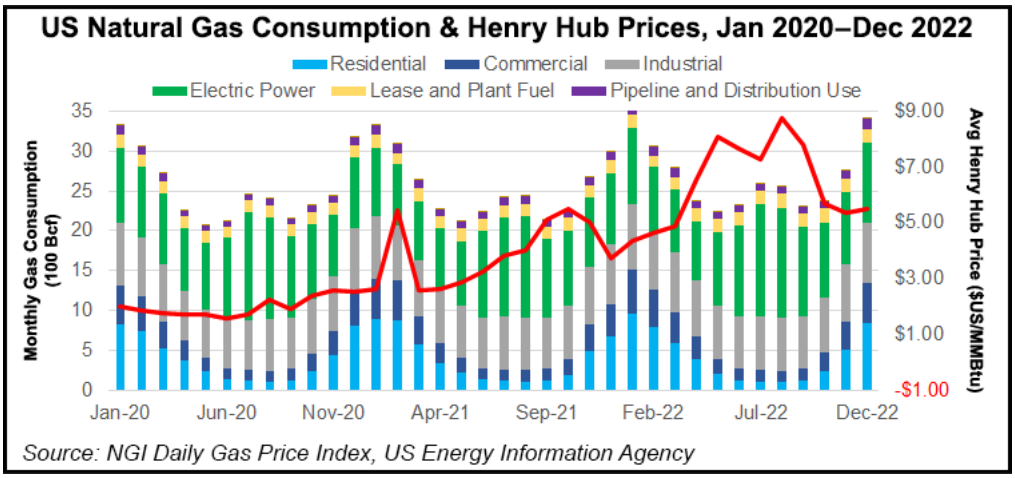
Meanwhile, natural gas consumption in the United States has been fairly flat in recent years, but it is far from going away.

The share of natural gas in the electricity generation market is forecast to decline 1% to 38%, a trend that may continue into 2024, according to EIA.

The global macroeconomic trend may be lurking behind the decline in natural gas generation.

Residential and commercial heating, the primary driver of natural gas demand in the winter, could average slightly lower than usual at around 46 Bcf/d because of warmer temperatures, EIA noted. In February, average consumption is expected to be around 43 Bcf/d, "which is also less than the five-year average, as forecasts…indicate above-normal temperatures for February in the eastern part of the United States."



Source: NGI Daily Gas Price Index, US Energy Information Agency

That said, "potential *natural gas supply constraints in New England* could cause large price increases *if extreme weather hits the region*," EIA said.

"Increases in U.S. natural gas production, relatively flat liquefied natural gas exports and declining domestic consumption in the electric power and industrial sectors will limit upward pressure on prices in 2023," EIA said.

Natural Gas Stoves? Still Here

Meanwhile, 2023 kicked off with a new dilemma to natural gas customers: whether natural gas stoves pose a new candidate for prohibitions by regulatory agencies.

RMI, formerly Rocky Mountain Institute, in a study published in November linked gas stoves to childhood asthma. That sparked U.S. Consumer Product Safety Commission (CPSC) member Richard Trumka Jr. to call them into question.

However, CPSC Chair Alex Hoehn-Saric clarified that the commission is "not looking to ban gas stoves and the CPSC has no proceeding to do so.

"CPSC is researching gas emissions in stoves and exploring new ways to address health risks. CPSC also is actively engaged in strengthening voluntary safety standards for gas stoves. And later this spring, we will be asking the public to provide us with information about gas stove emissions and potential solutions for reducing any associated risks."

AGA's Harbert said the recent studies regarding gas stoves "are based not on facts and data, but on literature reviews…" Some researchers "entered into the study with the assumption that asthma and gas stoves" are linked, "and attempted to then find what percentage of children [with asthma] were exposed or potentially got asthma from gas stoves…"

Harbert also noted "a study that was done in 47 countries looking at 512,000 different cases, so not an insignificant sample there. And that study concluded that there was no linkage between gas stoves and asthma all across the world…

"I'm hoping that in whatever process that regulators follow, that we include all of the evidence and we don't cherry-pick which studies are relied upon."

Sitherwood also commented on the gas stove issue in light of *December's Winter Storm Elliott*.

"We just had, for example… in a lot of places across the country some severe cold weather that lasted for a number of days," Sitherwood said. "Gas was working, people had hot water and they were able to cook, and all of those are very meaningful to them and I think our customers understand that." ■

Morgan Evans

Wave of Long-Term European LNG Contracts Seen Likely This Year

European LNG offtakers in 2023 are expected to continue the flurry of contracting activity that closed out 2022, as more import infrastructure comes online, larger buyers recapitalize and policies become clearer.

Since November, European buyers including *Engie SA*, *Galp Energia SGPS SA*, *Ineos Group Ltd.* and *RWE AG* have signed deals to buy U.S. liquefied natural gas for 15 years-plus. During the same time, *Trafigura Group Pte. Ltd* secured a $3 billion loan backed by the German government to buy more gas for the country. ConocoPhillips also *signed contracts* with QatarEnergy to move more of the super-chilled fuel to Germany.

U.S. LNG projects are poised to benefit most from the contracting rush. Sponsors signed long-term agreements in 2022 to supply nearly 50 million metric tons/year (mmty) of LNG, mainly to Asian buyers and portfolio players. European offtakers accounted for only 11.4 mmty of the total. It is estimated that Europe needs anywhere from 50-75 mmty of long-term LNG supplies

...cont'd pg. 11

from the United States alone to help replace the decline in Russian imports.

Many countries across Europe have been working to build more LNG import capacity. It was a necessary step before buyers could "really settle into working on some long-term deals," said LNG Allies CEO Fred Hutchison.

Germany Leading Pack

Nowhere is that more evident than in Germany, Europe's largest gas consumer and once the most dependent on Russian imports. The *country has chartered* six floating storage and regasification units and is working to support construction of its *first onshore import terminals* at breakneck speed.

"I think things are about as far advanced as they can be in Germany given when this crisis began" in February 2022, Hutchison told NGI. "My view is that there has been a lot going on behind the scenes, and we'll start to see more specific announcements early in 2023."

Some of Europe's larger gas buyers, including France's Électricité de France SA, Germany's Securing Energy for Europe GmbH (SEFE) and Germany's Uniper SE *have been nationalized* and recapitalized. Others have been quasi-nationalized after a stretch of record high commodity prices last year weighed on balance sheets. That has also slowed contract negotiations.

"It's taking politicians time to recognize the severity of the problem, and they're therefore missing out," said a U.S. LNG executive who did not want to be named discussing ongoing contract negotiations. "That has started to break down a bit, evidenced by the Engie deal, by the Galp deal and others.

"The interest from Europe is definitely there…I would anticipate around the middle of 2023, the end of 2023 and into 2024, you're going to see a lot more Europeans come to the market," the executive added. "The volumes we're hearing about are in the tens of millions of tons."

Uniper and SEFE in particular are expected to join other German buyers in clinching more long-term supply deals. German utilities *EnBW Energie Baden-Württemberg AG* and RWE signed deals last year.

A German government official told NGI that the country is doing everything it can to support additional gas purchases, but it would ultimately be up to the private sector. The government's support for strengthening gas supplies, the official said, was evident by its staunch opposition to the *European Union (EU) price cap* on the Title Transfer Facility that is set to take effect next month.

While there are limited supplies remaining, the United States may be the best option for European offtakers. The continent accounted for roughly 70% of all U.S. LNG exports in 2022. The United States also has the most shovel-ready projects in the world. About 20 projects are either under construction, have been approved by regulators or proposed for the country.

While Qatar is working to *boost its LNG output* from 77 mmty to 126 mmty this decade, its relationship with Europe has been complicated by a bribery scandal involving European lawmakers and the country.

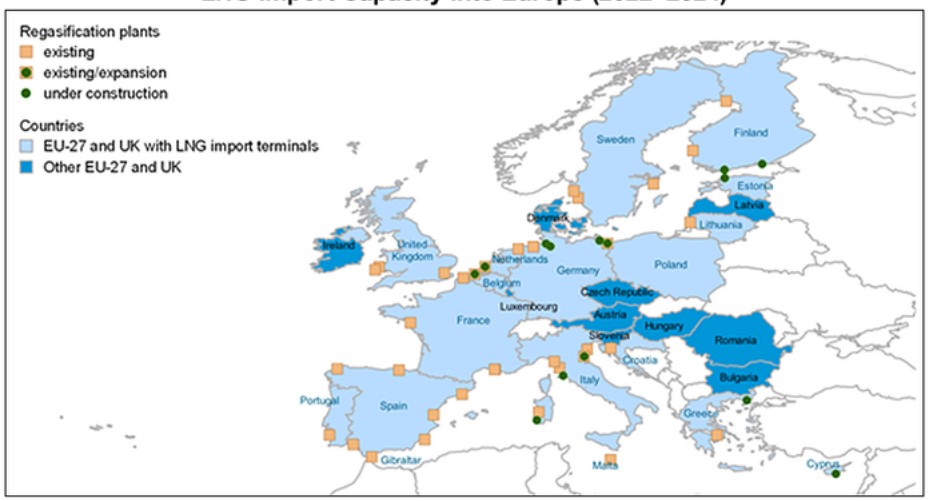
Instability in places like Africa, and a lack of progress on projects in other countries including Canada and Australia, also have the United States well positioned, even though questions remain about how much new capacity can be built in the country in the coming years. European offtakers signed their new supply contracts with U.S. projects last year, except for one between Australia's Woodside Energy Group Ltd. and Uniper.

Mixed Signals

European buyers have also waded through a wave of policymaking and mixed signals as EU lawmakers moved to respond quickly to soaring energy costs and supply shortfalls left by Russia.

The International Energy Agency has warned that the continent could face a *roughly 1 Tcf gap* in supplies this year, meaning more work is ahead to secure *...cont'd pg. 12*

LNG Import Capacity into Europe (2022–2024)



Note: Map displays existing and under construction LNG import capacity in the European Union and UK as of November 2022. Capacity under construction is expected to come online in 2023–24. LNG = liquefied natural gas.

Source: U.S. Energy Information Administration using data from the International Group of Liquefied Natural Gas Importers and trade press

additional volumes. At the same time, EU climate law requires emissions to be cut by 55% by 2030, while the bloc is ultimately targeting climate neutrality by 2050.

"Europe definitely has to continue to adjust its policies and regulations in order to take substantially more long-term LNG and replace Russian gas," said Poten & Partners LNG consultant Majed Limam.

"The long-term environmental impact is one of the drivers – policy limiting long-term natural gas usage can only complicate buyers' lives as they compete for long-term LNG commitments, and potentially muddle financing of supply projects," he told NGI.

The deep-seated reluctance to sign long-term LNG deals in Europe because of broader environmental goals is beginning to ease. The 10-year supply deals that would be ideal for Europe to meet net-zero targets in 2050 are not viable for U.S. project developers grappling with cost inflation and weak financial markets, something sellers are making clear during negotiations.

Furthermore, as contract talks continue to evolve, both buyers and sellers are finding ways to accommodate one another. Some of the deals signed late last year with European offtakers included provisions to use certified natural gas or frameworks to lower the carbon intensity of U.S. liquefaction plants.

Senior visiting research fellow Agnieszka Ason at the Oxford Institute for Energy Studies said she expects some European contracts to include renegotiation mechanisms as parties search for a balance between locking in long-term volumes now and meeting future decarbonization goals.

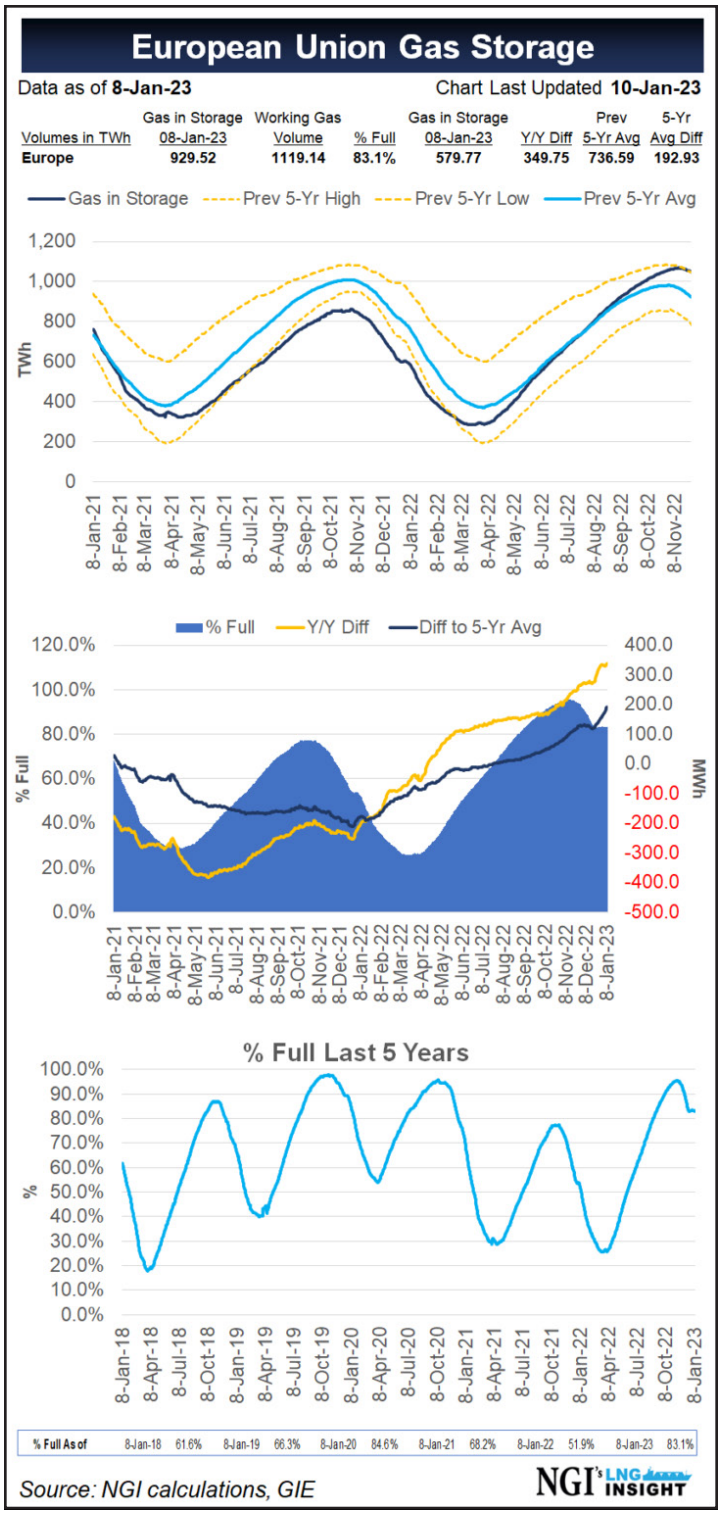
"These contracts should serve parties well in a low-carbon future," Ason told NGI. With that in mind, she said, sales and purchase agreements "will either already incorporate greenhouse gas emissions mitigation objectives, such as LNG sourced from certified gas or offset-paired cargoes, or, taking a long-term outlook, contain mechanisms to recalibrate contract terms in response to the emerging decarbonization requirements." ■

Jamison Cocklin

Warm Winter in Europe Eases Natural Gas Restocking Concerns, But 2023 Still Looks Daunting

An unseasonably warm winter and ample LNG imports are dampening expectations for high volatility when European countries start restocking natural gas reserves this spring, but risk still abounds for a region facing a tight supply outlook for years to come.

Headed into winter, the market faced the possibility of harsh weather and *China's return* to the liquefied natural gas



spot market, but neither have materialized. The region built higher than average storage levels before the heating season began in October, but prices have only *recently come down* to levels last seen since before Russia invaded Ukraine as supply concerns ease.

As Europe experiences what could be one of the warmest winters on record, Kpler Inc.'s Eleni Papadopoulou, lead gas and LNG analyst, told NGI that fears of a severe supply crunch and rationing are becoming "somewhat *...cont'd pg. 13*

subdued" thanks to a lifeline of "ample regional gas and LNG stocks."

[Want to know how global LNG demand impacts North American fundamentals? To find out, subscribe to LNG Insight.]

After a short cold snap in early December, the weather made an unseasonable shift, allowing some countries like Germany to make substantial injections to storage. By the end of December, Europe's natural gas inventories were 32 billion cubic meters (Bcm) higher than the same time in 2021, according to Kpler.

Morgan Stanley analysts estimated this week that Europe could be on track to exit winter with gas storage levels around 50% full. That could mean storage levels on the continent would be twice as high as the same time last year and closer to the five-year average.

European storage was around 83% full, trending along the five-year high, after the first week of January, according to *NGI calculations* of data published by Gas Infrastructure Europe. Europe's heating season typically begins in October and can last until March, when countries begin purchasing large volumes of natural gas to restock reserves.

"Price spikes due to prolonged and consistent market sentiment along with fundamentals seen in 2022 should in theory be reduced in 2023," Papadopoulou said.

Ending the winter with healthy reserves could help *temper prices* as traders weigh Europe's supply outlook against its ability to compete with China and other Asian LNG buyers for cargoes.

In a model conducted by the *International Energy Agency* (IEA) in December, Europe was expected to have a 27 Bcm supply gap after the heating season that would need to be filled by mostly U.S. LNG suppliers. Russian supplies that have since been cut almost completely helped to fill the continent's inventories last year. The United States exported around 53 million tons of LNG to Europe last year, according to data from Kpler.

If *China's LNG demand* growth is modest in 2023, Papadopoulou told NGI, Kpler expects the flow of additional volumes to be partially offset by potential import declines from Japan and South Korea, lowering the chances of spring price spikes.

"However, when looking at daily gas availability, there is an upside risk from the substantial annual decrease in Russian gas flows to Europe still leaving the market exposed to gas price volatility from multiple factors such as weather, and any unplanned infrastructure/supply issues," Papadopoulou said.

Fundamentally Undersupplied

At the crux of Europe's upside risk is the fact that it still faces a fundamentally tight natural gas market until at least 2024 when substantial additions of *U.S. LNG capacity* come online, Poten & Partners' Jason Feer, global head of business intelligence, told NGI.

European Union LNG Regas Terminal Storage

Data as of **8-Jan-23** Chart Last Updated: **10-Jan-23**

Country	Terminal	Inventory (10^3 m^3)	Chg	Max Cap (10^3 m^3)	% Util
Belgium	Zeebrugge	455.0	-58.0	566.0	80.4%
Croatia	Krk	35.1	-11.5	140.0	25.1%
France	Dunkerque	365.5	-42.8	570.0	64.1%
	Fos Tonkin	41.1	-10.1	80.0	51.4%
	Montoir	302.9	-40.1	360.0	84.1%
	Fos Cavaou	189.0	-57.8	330.0	57.3%
Greece	Revythoussa	158.4	0.0	365.0	43.4%
Italy	Rovigo	49.5	-20.8	250.0	19.8%
	Panigaglia	52.3	-9.5	75.0	69.7%
	Toscana	31.4	-21.7	137.2	22.9%
Lithuania	Klaipedos	34.4	-51.9	166.7	20.6%
Netherlands	EemsEnergy	136.6	-11.0	155.2	88.0%
	Gate	355.8	44.6	540.0	65.9%
Poland	Swinoujscie	153.4	-33.3	320.0	47.9%
Portugal	Sines	283.9	-12.8	390.0	72.8%
Spain	Barcelona	640.4	-7.3	760.0	84.3%
	Bilbao	336.9	-27.1	450.0	74.9%
	Cartagena	375.2	-7.2	587.0	63.9%
	Huelva	405.6	-17.8	619.5	65.5%
	Mugardos	209.7	-8.8	300.0	69.9%
	Sagunto	478.0	146.1	600.0	79.7%
UK	Grain	-	0.0	-	0.0%
Total		***5090.2***	***-258.6***	***7761.6***	***65.6%***

Source: NGI calculations, GIE NGI's LNG INSIGHT

Feer said the firm estimated that Europe would continue to secure the majority of LNG cargoes for the next year, barring an economic recession. The trick, he added, will be repeating the endeavor without the benefit of relatively cheaper Russian pipeline gas.

"There is focus on how the region will get through this winter, and Europe has been good about making that resupply happen so far," Feer said. "I think that's part of the problem. The focus has been on 'let's not freeze to death this winter,' and the next question is how to do it again and again for the next few years."

The largest addition to U.S. export capacity isn't expected for another two years. The first train of *ExxonMobil and QatarEnergy's Golden Pass LNG* southeast of Houston could start up in 2024, with the second and third trains expected to follow in 2025.

Venture Global LNG Inc. is ramping up production at *the Calcasieu Pass* terminal in Louisiana. Its Plaquemines LNG facility could have half of its 18 modular trains ramp up starting in 2024. The other nine trains could enter service sometime in 2025.

In the meantime, Russian pipeline gas flows are down around 80% compared to the same period last year, the IEA estimated at the end of December.

Rice University's Anna Mikulska, a nonresident fellow in energy studies at the Baker Institute for Public ...cont'd pg. 14

Policy, told NGI there is a chance Russia could further reduce volumes to influence market volatility at opportune times, although it has incentive to keep gas flowing as long as possible.

"Everything is possible and allowable in modern battle, and Russia has shown us it isn't necessarily driven by economic or emotional rationality," Mikulska said.

However, she added, "it's important to underscore it's not the Europeans that aren't taking Russian natural gas, it's the Russians that aren't sending it. Europe hasn't found a way to *displace its supply* quickly, and that will remain a problem throughout the year."

Most EU member countries now also have a legal requirement to reach storage levels of at least 90% by Nov. 1, which Mikulska said could keep European countries pushing up prices through the restocking season. Some countries, like Germany, have set more substantial benchmarks at 95%.

In a case study published by the Baker Institute in December, Mikulska and her co-authors posited that new storage requirements could increase market tightness throughout the year as governments limit the supply of natural gas for customers to inject into storage. It could also increase the need for gas rationing, especially in the summer.

"Because it is a mandate, price isn't going to be the main concern," she told NGI. "Over the summer, when demand is generally lower, we could see higher demand and increased competition with Asia." ■

Jacob Dick

China Seen as Wildcard for Global Natural Gas Market in 2023

China's thirst for LNG is likely to rebound in 2023, which could exacerbate the global energy crunch, but to what extent the country returns to the spot market remains unclear as it continues to grapple with Covid-19.

China has eased restrictions aimed at curbing the spread of the virus. Those measures limited economic activity and energy demand, but cases have surged in recent weeks as the so-called Covid-zero policies have been undone.

"The exit from zero Covid will likely be bumpy, slow and met with a rapid rise in cases and mortality," said Kpler economist Reid I'Anson. He said the reopening process is likely to take time. Kpler is forecasting annualized economic growth in the country of 3.5%, higher than its previous expectations, but well below levels of about 6% pre-Covid.

Assuming lockdowns aren't implemented again, the economic resurgence is still expected to boost overall natural gas demand in China, said Wood Mackenzie's Valery Chow, head of Asia-Pacific gas and liquefied natural gas research.

"However, this does not necessarily translate into greater LNG imports, given China's ability to call on more competitive substitutes like domestic coal and pipeline gas imports," Chow told NGI. "Domestic gas production has also been ramping-up quickly."

Spot Market Absence

China's LNG imports reached 80 million tons (Mt) in 2021, but they are projected to finish at just 64 Mt in 2022, according to Kpler data. The country is among the world's *largest LNG importers*. It has accounted for the bulk of long-term supply agreements that have been signed in recent years.

Spot buying dried up in 2022 as industrial demand declined and the country's buyers scoffed at high prices. Chow said Wood Mackenzie expects LNG demand to recover to 68 Mt in 2023, but she noted that would largely be driven by a ramp in existing long-term contracts.

Trident LNG's Toby Copson, global head of trading in Shanghai, pointed to a China National Offshore Oil Corp. (CNOOC) tender that closed Dec. 14 as an early indication of the country's activity on the spot market next year.

CNOOC purchased between four and six spot cargoes for delivery in 2023 at a price of roughly 30 cents above the Japan-Korea Marker, traders with knowledge of the purchase told NGI.

"I believe it's equal parts optimization of their portfolio and a little bit of front-running demand going into that period," Copson said of the CNOOC tender. "They're probably just getting a head start on things."

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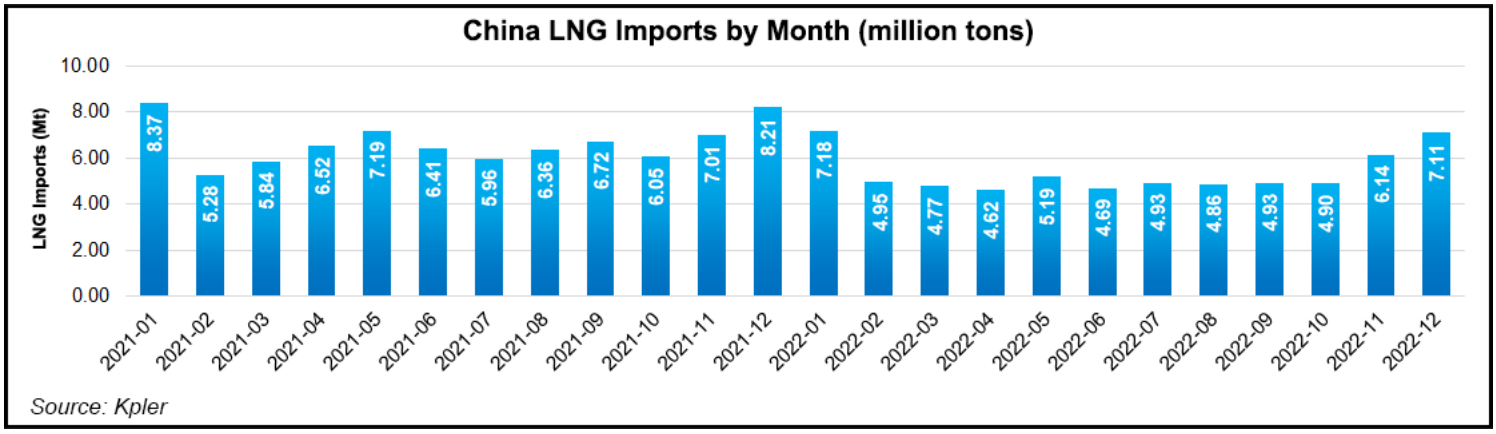


Global Competition

CNOOC has reportedly forecasted that China's natural gas imports will be 7% higher year/year in 2023. The additional demand could test Europe's efforts to bring in more cargoes as buyers there work to *restock inventories* for winter 2023-2024 without Russian imports.

Japan is also *stepping up efforts* to secure more LNG as global competition is poised to increase. The country plans to establish an LNG reserve, sign more long-term contracts and provide financial support for buyers.

Barring a cold snap that could accelerate spot buying deeper into winter, Copson added that China's storage inventories are comfortable for now.

"I don't feel that there's any panicking going on," he told NGI. "We haven't seen any cataclysmic demand come back, so I think most traders, portfolio players and majors don't seem to be in too much of a rough position just yet."

China has also deepened its relationship with Russia, which has led to an increase in pipeline imports. Gazprom PJSC said Dec. 17 that another record was set for deliveries to China on the *Power of Siberia* pipeline. Volumes exceeded contractual obligations by more than 16%, according to Gazprom.

Domestic gas production continues to rise as well. China National Petroleum Corp. produced record amounts of oil and gas from the Tarim Basin in 2022, according to state news media reports. Domestic coal output has also skyrocketed since blackouts impacted the country's grid in 2021.

As a result, LNG import growth is likely to be modest, with any notable gains on paper owing largely to weak buying during 2022. The CNOOC spot tender was the country's first since Russia invaded Ukraine in February.

I'Anson added that manufacturing output could also be tested in China if economies in the West contract amid the broader risk of a global recession. That would limit China's export demand for a variety of goods, he said.

Longer-term, though, the country is expected to remain a net importer and a force on the global gas market. It has invested billions of dollars on LNG import infrastructure.

"From a breakeven capex standpoint, they're going to have to run these terminals for many, many years to make them worthwhile," Copson said. "We can't be looking at a three- to five-year timeline, this is 20 years-plus." ■

Jamison Cocklin

Are Higher Canada AECO Natural Gas Prices a Pipe Dream?

Discounted pricing at the NOVA/AECO C natural gas hub in Southern Alberta is likely to remain a fact of life over the near term, even if pipeline expansions and LNG exports in Western Canada come online as scheduled, according to experts.

Abundant gas supply from the Western Canadian Sedimentary Basin (WCSB) and limited egress capacity out of the region have historically kept downward pressure on the price of gas delivered to AECO, the hub that is synonymous with TC Energy Corp.'s Nova Gas Transmission Ltd. (NGTL) pipeline system.

Pipeline maintenance on NGTL can also cause AECO prices to collapse as molecules have nowhere to go.

As a result, producers and marketers of Western Canadian gas have sought to maximize their exposure to higher prices in the United States and/or Eastern Canada. The challenge, however, is a lack of available firm transport capacity out of the AECO region and into these more lucrative markets.

There simply is "no more pipe out of the basin," a Calgary-based natural gas trader who did not want to be named told NGI. "It's all contracted…so there's not a lot of egress for the next little while."

Additionally, associated gas from the Bakken Shale of North Dakota has been displacing Canadian volumes on TC's Northern Border pipeline system, which connects WCSB supply with demand in the U.S. Midwest, according to FactSet Research Systems Inc's Connor McLean, senior energy analyst.

With pipeline space already limited, "any of that capacity that gets displaced really just backs up into the AECO market," McLean told NGI.

Limited capacity beyond Alberta's borders also can hinder the ability of Canadian gas to respond to price signals in the Western United States, he said.

"The marginal molecule for the western U.S. is not Canada," McLean said, but rather the Opal Hub in southwestern Wyoming. He explained that "Canadian gas is flowing as much as it can across the border, and every incremental molecule that California or Nevada or Utah needs, has to come from the Western Rockies."

NGI's *Opal forward basis curve* showed a $6.25 premium to U.S. benchmark Henry Hub for the balance of winter (February-March) as of Wednesday's (Jan. 4) trading day, according to *NGI's Forward Look*.

NOVA/AECO C gas for the balance of winter, meanwhile, was trading at an 83.9-cent/MMBtu discount. For summer 2024 (April-October), when maintenance on NGTL is expected to impact flows out of the region, the basis discount stood at $1.405. For the 2024/2025 winter (November-March), NOVA/AECO C gas was trading at $1.282 below Henry Hub.

What About LNG?

Liquefied natural gas exports from British Columbia (BC) could potentially offer some upside to AECO pricing. There are *several LNG projects in the works* in Canada, with one set to begin service in BC within two years.

TC's *Coastal Gaslink pipeline* is slated to add 2.1 Bcf/d of takeaway capacity to the *Shell plc-led LNG*

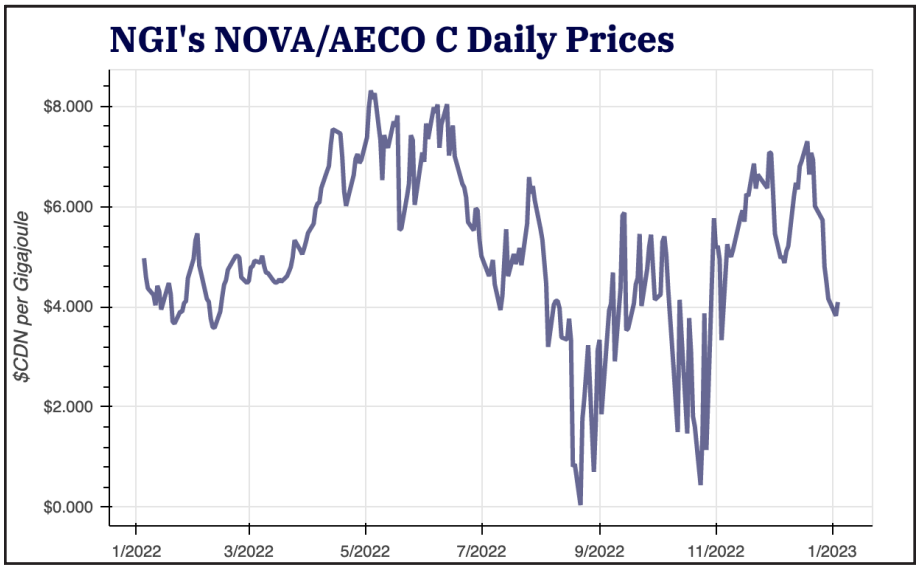
...cont'd pg. 16

Canada terminal under construction in Kitimat, BC. The pipeline is expected to be mechanically complete by the end of this year. LNG Canada's in-service date is forecast for 2025.

"In theory, all else being equal, that tightens the supply/demand balance," the Calgary trader said. "However, a certain amount of that has got to be priced into the market already… And then I think there's such vast amounts of gas in this part of the world that a lot of the export molecules will be met with a fresh production molecule."

McLean expressed a similar view.

"I know some people think that LNG Canada, if it starts on time, is bullish for AECO markets. I don't necessarily see it that way," he said. "I think that any incremental LNG demand is just going to spur an equivalent amount of increased Canadian production…You may see some short-term relief." However, "what we've seen historically is that Canadian producers grow to fill the space. They just kind of crush their own basis."



Canada E&P Gas Production

Leading exploration and production (E&P) companies working in the WCSB have signaled plans to increase gas output in 2023.

Tourmaline Oil Corp., Canada's largest natural gas E&P, is forecasting 7% year/year production growth in 2023 to 2.51 Bcf/d. By 2028, the firm expects to produce 3.22 Bcf/d. *Canadian Natural Resources Ltd. (CNRL)* expects gas production growth of roughly 5% in 2023 versus 2022, with plans to export about 36% of output outside the AECO market. Another 36% is allocated for consumption by CNRL's oilsands operations in Western Canada.

Montney Shale pure-play *Arc Resources Ltd.* is forecasting production growth of about 2% in 2023. CFO Kris Bibby told analysts during a 3Q2022 earnings call that the firm expected "very healthy pricing" through winter at the AECO hub, citing planned expansions of NGTL as a bullish driver.

However, Bibby noted that any pricing improvement would depend on the cadence of WCSB production growth. Arc's plan is "to make sure that we're selling as much gas as we can into the U.S. when there's periods of congestion at AECO."

TC, for its part, has sanctioned 1.3 Bcf/d of intra-basin capacity expansions slated to come online in Alberta by 2026, along with expansions of 300 MMcf/d and 400 MMcf/d to U.S. markets as part of the West Path and East Gate projects, respectively, on NGTL.

Gas demand on the Canada system has "never been stronger," said TC's Bevin Wirzba, executive vice president of Canadian natural gas pipelines, during the investor day in late November.

"In Alberta alone, we anticipate demand growth to be over 10% over the next decade," he said.

Demand within the basin, however, is unlikely to meaningfully strengthen AECO basis differentials, according to the Calgary trader who wished to remain anonymous.

So what would need to happen?

"The supply/demand balance…in Alberta and British Columbia would have to tighten to the point where AECO maybe needs to turn off some exports and keep some gas here," the trader said. "Or, just if the supply/demand balance tightens in general and more gas is going to leave the West Coast of Canada through upcoming LNG projects." ■

Andrew Baker

Global Reshuffle Presents 2023 Opportunities for Risk-Takers in Mexico's Natural Gas Sector

In 2023, Mexico's natural gas industry will be shaped by public-private partnerships and the shifting landscape brought about by Russia's invasion of Ukraine. Political risk for private and international firms, meanwhile, remains high.

Last year, President Andrés Manuel López Obrador's team said they would carry out costly *infrastructure works in conjunction with the private sector*. These include 7 GW of combined cycle generation plants, natural gas pipelines, and LNG export projects.

There are as many as *six liquefied natural gas export projects* planned for Mexico. These projects would re-export U.S. gas to Europe and Asia. In one instance, the gas would be sourced from the *Lakach offshore gas field* in the Gulf of Mexico and shipped off to Europe via a quick-build export facility.

While there has long been interest in these projects, enthusiasm boiled over following the war in Ukraine.

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In September, López Obrador even told German President Frank-Walter Steinmeier *that his country would help* Germans replace Russian natural gas.

State utility Comisión Federal de Electricidad (CFE) is also eager to use its natural gas capacity on myriad pipeline systems zigzagging Mexico and crossing over into the United States. CFE has 8.203 Bcf/d of capacity contracted in Mexico, but only 53% is being used. In the United States, CFE has contracted 11.3 Bcf/d, but only 38% is under use, according to the company.

With Russia's invasion of Ukraine, "the [LNG] opportunity today is clearly tremendous because of what we're seeing in markets," Francisco Monaldi of Rice University's Baker Institute for Public Policy told NGI. But, he cautioned, "I think the potential that is there is not going to be fulfilled because of the risks."

USMCA Dispute

Last July, U.S. Trade Representative (USTR) Katherine Tai announced the start of dispute settlement consultations with Mexico. She cited *unfair treatment of U.S. firms* in the energy sector, including in natural gas. She said Mexican actions violated the terms of the United States-Mexico-Canada-Agreement, or USMCA.

She specifically mentioned a June 2022 directive from Mexico energy ministry Sener that would *require natural gas marketers* and large consumers to source the fuel from either national oil company Petróleos Mexicanos (Pemex) or CFE.

[LatAm Energy Trends: From Mexico down to Argentina, from natural gas and LNG to crude oil and ESG, listen in as NGI's Christopher Lenton and Rice University's Francisco Monaldi discuss what to expect from the energy markets of Latin America in 2023. Tune into the Hub & Flow podcast now.]

That rule change has since been halted, but the dispute consultations are ongoing, with the real threat of potential penalties on Mexico. Duncan Wood of the Wilson Center in Washington D.C. said that he thinks the United States and Canada will "follow though."

"The wheels are turning and Tai will want to see progress from Mexico," while Canadian Trade Minister Mary Ng "is under pressure from Canadian investors to get some movement," he told *NGI's Mexico GPI*.

Matters are further complicated by energy sector regulators that have *been significantly weakened* by the López Obrador government. The energy permitting process has also become slow and burdensome.

Still, none of this has slowed *the growing momentum for nearshoring*, which promises to bring the three countries of the USMCA even closer together. This week, U.S. President Joe Biden made the first visit to Mexico City by a U.S. head of state in nine years. He was attending the North American Leaders Summit, which also included Prime Minister Justin Trudeau of Canada.

U.S. President Biden and Mexico President López Obrador in Mexico City

Source: Mexico Government

The trade dispute was kept out of the discussion as the leaders chose to focus instead on the opportunities presented by nearshoring and changing supply routes.

U.S. leaders have made it no secret that they seek to boost semiconductor production in North America. This would add to the major auto manufacturing business across borders, along with already existing, deeply integrated energy systems.

Growing Natural Gas Production

While Mexico will continue to meet a majority of its natural gas needs *through pipeline imports* principally from Texas, domestic *production is showing growth*. Pemex is targeting full-year average natural gas production of 4.67 Bcf/d in 2023, up 20% from the 3.88 Bcf/d averaged in the third quarter of 2022.

But despite this, and a high price environment, Pemex *continues to struggle financially*. "Pemex continues to lose money," Wood said. He said the Mexican government in 2023 needs to "decide if they are really willing to sink more billions into the firm ahead of the election when the money spent thus far has failed to turn the ship around."

Monaldi added that, "even though production has stabilized or slightly increased I don't think the prospects are good, and I think the company will continue to be in trouble for the foreseeable future with heavy debt."

Looking To 2024

One thing López Obrador has proven time and again is that he is not going to change his general position on energy policy. "Priority energy issues for this government will remain the *Dos Bocas refinery,* and the strengthening of state firms," energy consultant Eduardo Prud'homme wrote in a recent column for *NGI's Mexico GPI.*

Through to the end of his term in 2024, President López Obrador will continue to be the dominant actor

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in the sector, with rules determined at his whim, according to analysts. "I don't see Mexico moving into a more rules based economic system," academic Tony Payan said at the U.S.-Mexico Natural Gas Forum late last year.

Payan added that with an eye to the presidential election in 2024, López Obrador's pick as successor would probably be Mexico City Mayor Claudia Sheinbaum.

Sheinbaum has recently indicated a commitment to López Obrador's energy policies. She told reporters that she would seek to amend the constitution to grant CFE at least a 54% share of the generation segment, something *the current president failed to achieve*.

"In the opposition, no one stands out just yet, none that captures the imagination," Payan said. "If the opposition doesn't go as a united block, expect another Morena victory," Payan said. Morena is López Obrador's highly popular ruling political party. ■

Christopher Lenton

Column: Regulatory Risk Big Unknown in Mexico 2023 Energy Outlook

Editor's Note: *NGI's Mexico Gas Price Index, a leader tracking Mexico natural gas market reform, is offering the following column by Eduardo Prud'homme as part of a regular series on understanding this process.*

January 2023 brings with it new hope for Mexico's natural gas industry. It is an illusion to think that the environment for private investment will improve. But Mexico natural gas production is on the up. Priority energy issues for this government will remain the Dos Bocas refinery, and the strengthening of state firms. Massive energy exchange across the U.S.-Mexico border will continue unabated, even with commercial disputes as a backdrop.

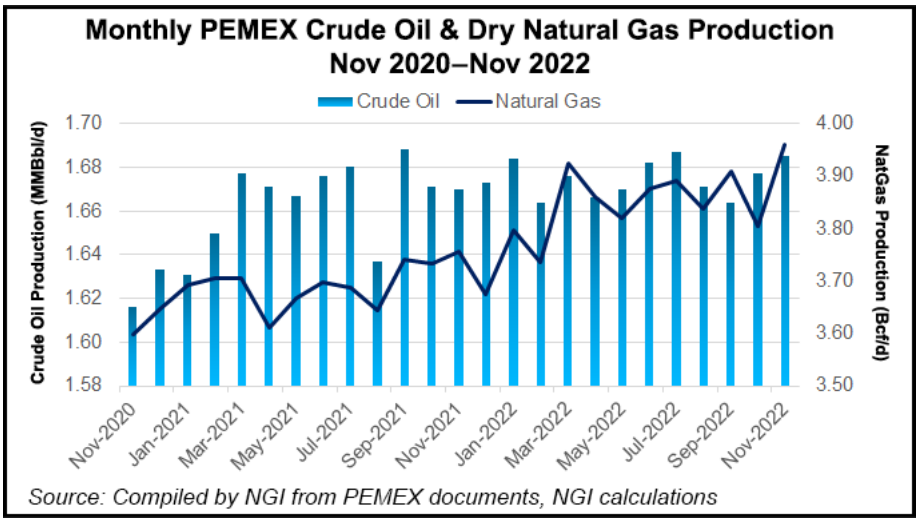
At the start of the year, the two sector regulators still have important vacancies. At the Comisión Nacional de Hidrocarburos (CNH), which is in charge of regulating the upstream segment, Alma América Porres Luna has left her position as commissioner after 12 years of outstanding work. Her talent as a geophysicist and her efforts to create the valuable National Hydrocarbons Information Center contributed to the institutional growth of the CNH. Her leadership was simultaneous to the consolidation of the CNH as the leading technical authority for the opening of the exploration and production segment to private investment. With her departure, the collegiate body that by law must have seven members, is now left with only three acting commissioners. This condition makes it impossible to hold sessions because the minimum quorum is four commissioners.

At the other Mexican energy regulator, the Comisión Reguladora de Energía (CRE), the president commissioner, Leopoldo Melchi, and the only remaining commissioner from the previous government, Guillermo Pineda, concluded their terms on December 31, 2022. The CRE governing body must also have seven commissioners, and with these departures it is left with four. President López Obrador must propose shortlists to the Senate to ratify the new appointments. At the time of writing this column, the president has developed a shortlist that includes Melchi along with two other directors of the Energy Ministry (Sener).

Meanwhile, the pandemic and the attempts at legal changes to reverse the 2014 energy reform created a significant backlog in the work of the CRE, complicating matters further.

There have been no announcements for replacements to fill the vacancies at the CNH. The government will maintain its practice of austerity in this regard, leaving the positions unoccupied so long as a minimum is met for the deliberative sessions. At some point the position will be given to a person related to the government whose thinking is aligned with the current energy policy. There will be no new rounds to assign new blocks, there will be no new contracts, and the commitment to increase oil and gas production will continue to be led by Petróleos Mexicanos (Pemex), not the private sector.

Lopez Obrador, or AMLO, is committed to Pemex. The policy has not been entirely unsuccessful, but it has been consistent. Production has certainly grown. However, it is difficult to see that this growth will be sustainable and sufficient to significantly reverse imports from Texas. According to CNH data, in November 2022 the daily production of methane, the main component of natural gas, showed a month-on-month increase of 335 MMcf/d. It is the highest growth recorded since January 2016. The big unknown is how many months ahead we will see this rate. An analysis of production patterns in the relevant fields ...cont'd pg. 19



suggests such growth is overly optimistic due to declining production in multiple areas. Ixachi and Quesqui are not sufficient to make up for the loss of associated gas from the maturing southeastern basins.

The only way for natural gas production to show sustained long term growth would be through unearthing massive reserves similar to those of the mega deposits found in the 1970s. Without new upstream bid rounds, and along with the rule changes that have affected private operators, investments in contracts for the exploration and extraction of hydrocarbons have fallen sharply in recent years. Exploration and production investment among private firms dropped from $3.3 billion in 2020 to $429 million last year. The country's proved, probable and possible reserves dropped from 23 billion boe to 22.1 billion boe in the same timeframe. Pemex remains in a poor financial position despite the high oil and gas price environment. The Dos Bocas refinery has swallowed up the attention of the state oil firm.

But some operators have said that they will continue injecting resources into exploration in Mexico. Italy's Eni SpA will invest approximately $120 million this year. Surely, with elevated prices, there will be more operators willing to continue in Mexico. However, AMLO's failed attacks in 2022 to change the laws of the energy sector have left a sour taste in the mouths of those in the sector. The perception of regulatory risk adds to the pressure.

Yet Mexico maintains geological potential. Mexico will not return to the big leagues of hydrocarbon suppliers in 2023, but the potential is there. It won't operate in the conventionally expected way. The energy attractiveness of Mexico in 2023 lies in its capacity as a re-export platform for Texan natural gas. Sempra's projects in Baja California and Sonora are those with the highest probability of execution. This company has demonstrated its management capacity to achieve high-level dialogue and carry out projects. The central unknown for this year is whether Mexico is capable of taking advantage of its potential, and whether it will work as it should toward strengthening partnerships and improving its investment climate.

Prud'homme was central to the development of Cenagas, the nation's natural gas pipeline operator, an entity formed in 2015 as part of the energy reform process. He began his career at national oil company Petróleos Mexicanos (Pemex), worked for 14 years at the Energy Regulatory Commission (CRE), rising to be chief economist, and from July 2015 through February 2019 served as the ISO chief officer for Cenagas, where he oversaw the technical, commercial and economic management of the nascent Natural Gas Integrated System (Sistrangas). Based in Mexico City, he is the head of Mexico energy consultancy Gadex. ■

Eduardo Prud'homme

CFE Alliances Driving Mexico Natural Gas Infrastructure Growth as Imports Cool Off

The past year marked a renewed sense of collaboration between Mexico's state power utility Comisión Federal de Electricidad (CFE) and private sector energy firms, resulting in the sanctioning of new natural gas infrastructure projects and agreements to advance stalled ones.

Meanwhile, Mexico's pipeline natural gas imports from the United States were down year/year during summer, which is typically Mexico's high-demand season for gas.

U.S. pipeline flows to Mexico averaged 6.05 Bcf/d in July 2022, down from 6.37 Bcf/d in July 2021, according to the U.S. Energy Information Administration.

This trend is due in part to "an apparent structural recovery in Mexican dry gas output that, since last summer and despite the persisting short-term volatility, has led to stronger gas-to-gas competition against Mexico's pipeline imports of U.S. gas," Wood Mackenzie's Ricardo Falcón, a Mexico natural gas analyst, told NGI.

State oil company Petróleos Mexicanos (Pemex) has managed to stabilize a years-long decline in natural gas production, largely through increased output at its newly incorporated *gas-rich fields such as Quesqui and Ixachi.*

Falcón also cited "near record-high volatility and spreads in key U.S. benchmarks" such as Henry Hub, Houston Ship Channel and Waha, "which have underscored both the liquidity constraints across Mexico's gas trading regions and Mexico's incremental exposure to U.S. natural gas market dynamics along the border."

Waha in particular has become a more relevant pricing location for Mexico, as *U.S. gas exports via West Texas* have grown rapidly in proportion to South Texas – historically the primary exit point.

This is due in large part to new infrastructure in western Mexico such as Fermaca's Waha-to-Guadalajara system.

Flows from West Texas to Mexico likely would be even higher if Mexico had underground storage capacity, according to NGI's Josiah Clinedinst, markets analyst.

"If there were natural gas storage built in Mexico, especially in Hidalgo state, near Samalayuca or El Encino, there would probably be no more negative Waha prices until takeaway capacity in West Texas became an issue," Clinedinst said.

CFE Driving Pipeline Growth

CFE is Mexico's largest power generator, and its main importer and marketer of natural gas from the United States. Domestic production by Pemex has fallen well short of CFE's needs over the past decade, resulting in a building spree of cross-border pipelines to import U.S. gas, with CFE as the anchor shipper.

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CFE had about 3.2 GW of natural gas-fired power plants under construction with another 3.3 GW in development as of November, according to Guillermo Turrent, head of the Energy and Infrastructure Advisors consultancy.

Calgary-based TC Energy Corp. and San Diego, CA-based Sempra have been among the main players in the pipeline buildout, and each firm has signaled plans to continue building out their respective natural gas networks in Mexico.

TC is forecasting Mexico's natural gas demand to grow by 35% from current levels to reach 12 Bcf/d by 2030, and for Mexico's gas imports from the United States to reach 9 Bcf/d from about 6 Bcf/d currently.

In August, TC and CFE reached a final investment decision (FID) on the *444-mile, $4.5 billion Southeast Gateway* offshore natural gas pipeline.

The 1.3 Bcf/d conduit would originate onshore in Tuxpan, Veracruz, then proceed offshore before making landfall again at Coatzacoalcos, Veracruz, and Dos Bocas, Tabasco. The companies are aiming for the project to enter service in 2025.

Southeast Gateway would function as an extension of TC and Sempra's existing 2.6 Bcf/d Sur de Texas-Tuxpan (STT) pipeline, for which CFE is the sole capacity holder. Flows on STT averaged 952 MMcf/d in September, according to data from energy ministry Sener.

Southeast Gateway would serve industrial demand in southern Veracruz state "and potentially some LNG export markets," TC's Stanley Chapman III, vice president of U.S. and Mexico natural gas pipelines, said in late November.

Over the nearer term, TC is aiming for the south section of the 886 MMcf/d Villa de Reyes (VDR) pipeline in central Mexico to enter commercial service this year, along with the VDR Lateral, which is mechanically complete.

This would complete the 261-mile VDR pipeline, which is meant to serve power generation facilities in Central Mexico.

The timeline for completion of the adjacent Tuxpan-Tula pipeline remains less clear, although progress is being made, according to TC management.

As of July 1, 2022, TC has begun transport service for CFE on the Tuxpan-Tula East and VDR north segments, Chapman said during TC's investor day on Nov. 29.

He said that "we're working with the CFE to resolve the remaining stakeholder issues on the VDR South segments so it too can be completed and placed into service."

Chapman added, "On the remaining sections of the Tuxpan-Tula pipeline, we're working with the CFE to advance the west portion…I expect to have more information on that to you shortly. And then lastly, we're continuing to evaluate the central section, referred to as the reroute of

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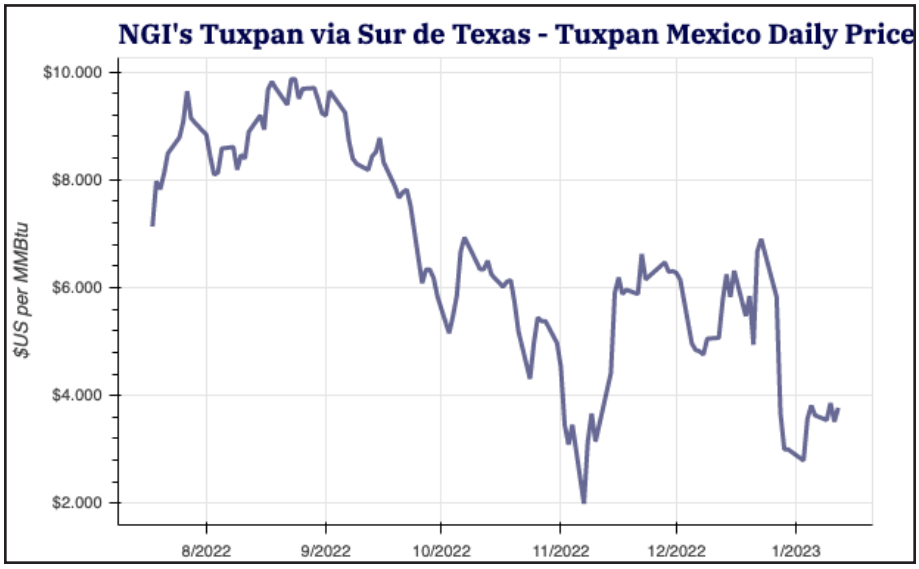

the Tuxpan-Tula pipeline, and we're targeting an FID for that in the first half of 2023."

Sempra Advancing LNG, Pipeline Projects

Sempra, for its part, announced *a memorandum of understanding in early 2022 with CFE* to develop two new liquefied natural gas projects, and to resume operation of the Guaymas-El Oro pipeline in northwestern Mexico, which has been out of operation since 2017. The other two projects comprise the proposed, roughly 2 million metric tons/year (mmty) *Vista Pacifico terminal* in Topolobampo, Sinaloa, and a possible regasification project in La Paz, Baja California Sur, neither of which has been sanctioned.

These are in addition to the roughly 3 mmty ECA Phase 1 export terminal in Baja California, which has a targeted in-service date of mid-2025. Plans are to source gas from the Permian Basin.

A 12 mmty second phase of the ECA terminal also is in development, though it to has yet to reach FID.

The timeline for a possible re-route and/or restarting of service on Guaymas-El Oro remains unclear, the firm indicated in its third-quarter report to shareholders.

Other LNG projects under development but yet to reach FID include a *2.6 mmty proposed terminal by Mexico Pacific Ltd. LLC* and the *Amigo LNG project* in Guaymas, Sonora.

New Fortress Energy Inc., meanwhile, is developing an offshore LNG export hub with CFE and an offshore natural gas production-to-LNG project with Pemex.

North of the border, meanwhile, U.S. midstream giant Oneok Inc. is developing the roughly 2.8 Bcf/d Saguaro Connector pipeline. If sanctioned, it would export Permian gas from Oneok's existing WestTex intrastate pipeline system to Mexico.

The project could also serve LNG exports on Mexico's West Coast, the company said. ■

Andrew Baker

NGI STAFF PREDICTIONS

What Are NGI's Thought Leaders Forecasting for Natural Gas Prices, LNG, Russia – and Beyond?

Asking natural gas and oil executives about the market, their projects, cash flow and budgets is a staple of the NGI Thought Leader team's daily routine. Turning that microphone around to ask journalists the questions is a bit trickier!

The Thought Leader team was up for the challenge, though, to editorialize as we enter 2023. Here are some of the hot natural gas topics and beyond that NGI's editors foresee this year. What's the direction of natural gas prices? How much could the LNG market grow?

Is more pipeline infrastructure going to reduce bottlenecks in Appalachia and the Permian basins? What potential issues could NGI's audience face?

Editor-in-Chief Alex Steis plans to closely follow Russia's war with Ukraine and its continuing impact on Europe – and U.S. LNG supply.

"I am very interested to see whether Europe is able to quit Russian natural gas supplies for good," Steis said. "In retaliation for Russia's February 2022 attack on Ukraine, European countries weaned themselves off of Russian natural gas supplies, with the common refrain of 'never again.'

"However, time is a funny thing, so it will be interesting to see whether the individual bans hold up when and if the war ends," Steis said. "If down the road the picket line gets crossed, and the spigots get turned back on, there will be a direct impact on North American LNG export demand, which in turn will put some serious downward pressure on North American natural gas prices."

Predicting Natural Gas Prices? A Tricky Business

Determining the direction of natural gas prices is a bit of a sticky wicket, Steis said.

"Answering this question correctly requires a crystal ball, but I'll take a stab – with a twist.

"While Henry Hub cash prices finished 2022 in sub-$4/MMBtu territory, I think the real question is whether natural gas prices as low as $3 to $4 will become a thing of the past over the next few years.

"As the largest producer of natural gas globally, the U.S. has no lack of supply…unless of course someone else is willing to pay more for the molecules.

"With numerous projects ramping up to increase U.S. LNG export capacity in the coming years, we could be in a situation where gas with a $3 or $4 dollar handle will be forgotten about, if not in 2023, then I believe, quite possibly by 2025."

NGI Senior Editor Chris Lenton, who oversees coverage of Mexico's natural gas market, expects 2023 "to be another year of great change, unpredictability and volatility. This will create many opportunities for swift-moving countries and companies.

"I'm curious to see how changing supply chains and nearshoring opportunities change the North American energy landscape," Lenton said. He noted that the disputes between North America regarding the U.S.-Mexico-Canada Agreement, aka the USMCA, "could dampen the spirit of cooperation; or a positive outcome could bring the region closer together.

"The war in Ukraine," Lenton said, "will continue to change the global energy sector and impact natural gas prices and market conditions. So too might an economic recession."

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Weather: That Is The Question

Asked what market forces could cause natural gas prices to shoot higher this year, NGI's editorial team cited not only Russia's war with Ukraine, but the weather as well.

"Any expansion of the conflict in Ukraine that would further jeopardize trade flows would likely push global prices higher given unease over the supply outlook," said **Senior Editor Jamison Cocklin**, who oversees *NGI's LNG Insight*.

"Weather is always also a wildcard," he noted. "Severe cold in the northern hemisphere that would boost demand in North America and lead to a protracted battle for cargoes between Asia and Europe would likely push major benchmarks higher given how interconnected the global gas market has become."

Associate Editor Morgan Evans said, "Domestically, it's weather, weather, weather! Any substantial heatwaves, like those seen in 2022, and any more Arctic blasts, across the Northeast in particular, would cause another surge in natural gas prices."

NGI's **Kevin Dobbs, Senior Editor of Markets**, agreed.

"Weather is always king, and summers seemingly get hotter and drier by the year," he said. "Another scorching summer would propel demand in the U.S., as well as Europe, just as the continent, no longer able to rely on Russian fuel, scrambles again to stock up on American liquefied natural gas for the next winter.

"The confluence of such events," Dobbs said, "coupled with limited global supplies, propelled prices to near $10 in summer 2022 and could again this year."

'Expect The Unexpected'

Price and Markets Editor Leticia Gonzales said, "If there's anything the last three years have taught us, it's to always expect the unexpected. However, based on the supply/demand fundamentals at hand, I expect the U.S. natural gas market to experience the first year of 'normalcy' in quite some time. That means a shift back to the $3-4 gas prices the market had grown accustomed to over the past decade, along with less volatility, if we're lucky.

"This is all thanks to projections for robust supply and slightly lower demand," Gonzales said. "This should be welcome news to a market that has endured huge daily price spikes regularly in recent years. Of course, we'll be on watch for any unexpected developments as the year plays out."

NGI's **Jacob Dick, Associate LNG Editor**, said, "On the international front, I think Russia still has some levers to pull when it comes to stoking supply concerns for Europe. Combined with potential maintenance issues at global LNG terminals – or even attacks on infrastructure – there could be even more volatility this year."

NGI **Senior Editor Andrew Baker** agreed with his colleagues about the situation in Europe – and how volatile natural gas prices could be this year.

"It's hard to imagine a scenario of year/year natural gas price growth in 2023, absent another Ukraine-magnitude disruption to the market." Baker said.

For the United States, he noted, "keep an eye on the Rocky Mountain region, which is now the swing supplier for West Coast markets amid capacity constraints out of Canada and the Permian Basin.

"As a source told me recently, 'every incremental molecule that California or Nevada or Utah needs, has to come from the Western Rockies.'"

LNG, LNG, LNG…

"Europe is likely to exit the winter with healthy natural gas storage inventories, which will ease the continent's restocking burden this spring," Cocklin said when asked what positive signs the market may see.

"And at some point, likely sometime in the first quarter, Freeport LNG will finally return to service!"

The Texas export terminal has been out of service since an explosion last June.

NGI's LNG expert also foresees more European offtakers signing long-term contracts with U.S. export projects this year. That would "continue the momentum we saw in 2022 and keep the U.S. at the front of the pack in terms of global supply additions," he said.

Cocklin didn't name any names, but he noted, "We're also likely to see at least one U.S. natural gas producer enter the LNG market this year. That producer is likely to take an equity stake in a new liquefaction project, announce some sort of a supply agreement with an overseas end-user or strike some other type of novel deal."

Cocklin also expects to see "at least one U.S. LNG project…sanctioned in 2023, likely Port Arthur LNG, Delfin LNG or Rio Grande LNG."

Said Dick, "The refrain of the prior year has been that there isn't enough additional LNG capacity coming online before 2024 to fill the gaps. The projects that are moving forward are in the United States.

"I think there will be a magnifying glass on projects like Golden Pass, Venture Global LNG Inc.'s Plaquemines LNG, and any floating terminal that looks like it may move forward."

Some people, Dick said, "are still holding their breath about whether investors, particularly in Europe, are going to break the dam and bring a flood of support to new infrastructure projects. There is a strong consensus among analysts I talk to that any new LNG volumes will easily find a home for the next decade or so, but how many additional tons get added to the market may be determined in the next few years."

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NGI Staff | Jekyll Island, GA, November 2022

Infrastructure Roadblocks?

The NGI team shared some of the possible issues facing the natural gas and oil industry.

Cocklin said the "debt and equity markets will continue to be a challenge for infrastructure projects seeking financing as the global economic outlook weakens.

"This could create longer-term supply issues for the global gas market at a time when more investment is needed."

Gonzales also weighed in on infrastructure challenges.

"Infrastructure will continue to be hotly debated in 2023 as consumers try to understand the complexities that have led to soaring natural gas prices in some regions, including years-long underinvestment in natural gas pipeline capacity and historically low storage inventories," Gonzales said.

"In other areas of the U.S., the failure of natural gas-fueled power generators in key demand markets at the height of a major winter storm will likely catch the attention of state and federal regulators. Both issues have the potential to set off increased oversight that could ultimately lead to long-term changes for the natural gas industry."

Dobbs was in agreement.

"New pipeline capacity is on the way — or at least planned and in the works — in the Permian Basin this year," Dobbs said. "It is sorely needed. Without it, the U.S. could struggle to deliver both LNG to the water and, critically, get much-needed gas to energy-depleted California."

'Big-Ticket Projects'

Mexico may see some "big-ticket projects" move toward a positive final investment decision this year, Lenton said. Elections are scheduled soon in Latin America, he noted.

"On a political note, this is the year that Mexico will start to seriously debate its future around the 2024 election," Lenton said. "Farther south in Argentina, a general election is also set to take place in 2023 as Vaca Muerta looks to become a natural gas export option."

NGI's **Carolyn Davis, Managing Editor of News**, said one of the "bigger issues" is likely to be centered on jobs.

"I think one of the bigger issues that does not get a lot of attention by the media is the labor issue facing many producer and oilfield services firms," Davis said. The companies "know it, and they mention it in conference calls and in surveys. But it's a tough, tough market out there.

"Many people graduating from college don't want to work for traditional oil and gas companies, even as many operators are improving their technologies and transitioning to more renewable resources.

"It's also particularly more stressful today as some people are choosing to work from home. As one executive said, 'you can't build a rig or move supplies to the gas and oilfields without people. Robots can't handle everything.'

"Meanwhile, turnover is ongoing at the top, as executives who've carried their companies through the past few volatile years begin retiring. There are plenty of people

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to promote, but then, who fills their spots? On top of that, I've spoken with executives about the inability of some job candidates to pass drug tests.

"While there is a lot more efficiency in the industry, I think this labor crisis needs to be continually addressed to ensure our energy security," Davis said.

Transition…And Split Congress

The global energy transition is poised "to continue to gather steam," Lenton said, "with natural gas playing a part replacing coal in many grids, and major energy companies continuing to add renewable energy to their portfolios."

Evans expects hydrogen projects also to be in the news.

"It will be exciting to see what the finalized plans will be for the use of natural gas in the regional hydrogen hubs as states begin to send in their full applications for funding this spring," Evans said. "With a final decision expected in winter 2023-2024, a new nationwide use for natural gas for domestic purposes will surely affect the fuel's demand moving forward, and perhaps become poised as a new signal for prices."

Legislatively, it may be a tricky year for the U.S. energy industry. President Biden had two years to pass climate-related legislation and roll back some less stringent oil and gas regulations in a Democratic-controlled Congress. Now, the GOP holds slim control of the House.

"Even with a Democratic majority, we saw how tight margins in Congress presented difficulties with passing infrastructure packages," Dick said. "If the industry is expecting permitting reform this year, I think a split Congress presents some bumps in the road."

Evans agreed.

"A split Congress and the typical slow movements that would arise from political back-and-forth may initially hurt the oil and gas industry as slow-to-pass final decisions from lawmakers delay projects or leave policies ambiguous," Evans said. "That said, hopefully negotiations, bargains and compromises lead to more stable policymaking that persists through more than what would arise from a single-party Congress.

"What has seemingly hurt the oil and gas industry, or at the very least been unhelpful, is legislation from such one-sided governments that is erased once the next party comes in and undoes any footing that was gained under the previous party's rule."

Still, America is "very likely to gain a new foothold as a leader in oil and natural gas exports, solely because Russia is likely to be taken down a few pegs amid its invasion of Ukraine," Evans said. "The U.S. has taken on an expanded role as the West's global energy supplier."

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There's "greater potential" for grid issues to build out more transmission for renewable resources to arise over the coming decade, according to Evans.

"There have been calls from the energy transmission sector the last few years that upgrading the grid and adding more transmission lines is going to be pertinent and paramount to support the renewable generation that is scheduled to be constructed and brought online," Evans noted.

"The generation from wind and solar is surely coming and ramping up, but it would seem the efforts are really all for naught if the energy produced is unable to reach the energy-hungry consumers." ■

NGI Staff

. . . from Volatility Laces 2023 NatGas Price Outlook Amid Robust Production, pg. 1

While demand for U.S. LNG reached record levels in 2022 and is expected to remain elevated, no new domestic export facilities are slated to come online this year, limiting exporters' ability to ramp up further to meet global energy needs. Europe, in particular, boosted its demand for LNG in the wake of recent Russian *moves to cut off pipeline gas exports* to the continent amid the Kremlin's ongoing invasion of Ukraine. Europe is expected to do so again ahead of next winter.

Following *a fire last June*, the Freeport LNG facility in Texas is slated to return to service in stages by the end of March, steadily building back to 2.38 Bcf/d capacity. That will help balance supply/demand to a degree, Wilson said. But if East Daley's output projection proves accurate and either the remainder of this winter or the coming summer prove modest in terms of demand, production levels may be too high this year to support a sustainable price recovery, he added.

"Of course, there are wildcards," Wilson said. "The weather dramatically shifts and demand could increase with it. Production could always pull back. But from what we see now, it seems we could be oversupplied" in 2023.

Infrastructure Limits, Takeaway Woes

What's more, late in 2022 and again early this year, cash prices in West Texas were under heavy pressure amid a surge in production, limited pipeline capacity, and takeaway constraints compounded by maintenance events.

Spot prices at the *Waha* hub in West Texas, for example, briefly flipped negative last year amid a supply glut. NGI's Spot Gas *National Avg.* in the first week of January continued to more than double prices at Waha and several other Texas hubs, including *El Paso Permian*.

Analysts at The Schork Report noted that West Texas prices have been periodically under pressure for several years, and they expect this to remain the case, "owing to robust associated gas production and pipeline constraints throughout the market area."

The American Gas Association's (AGA) Morgan Hoy, senior market and regulatory analyst, told NGI that the United States needs to expand its production and delivery infrastructure to keep pace with demand – in Texas, the Northeast and elsewhere. She said positive momentum, however, could remain elusive because capacity limits exist in large part because of regulatory restraints and political pressure to curb fossil fuel development to help combat climate change.

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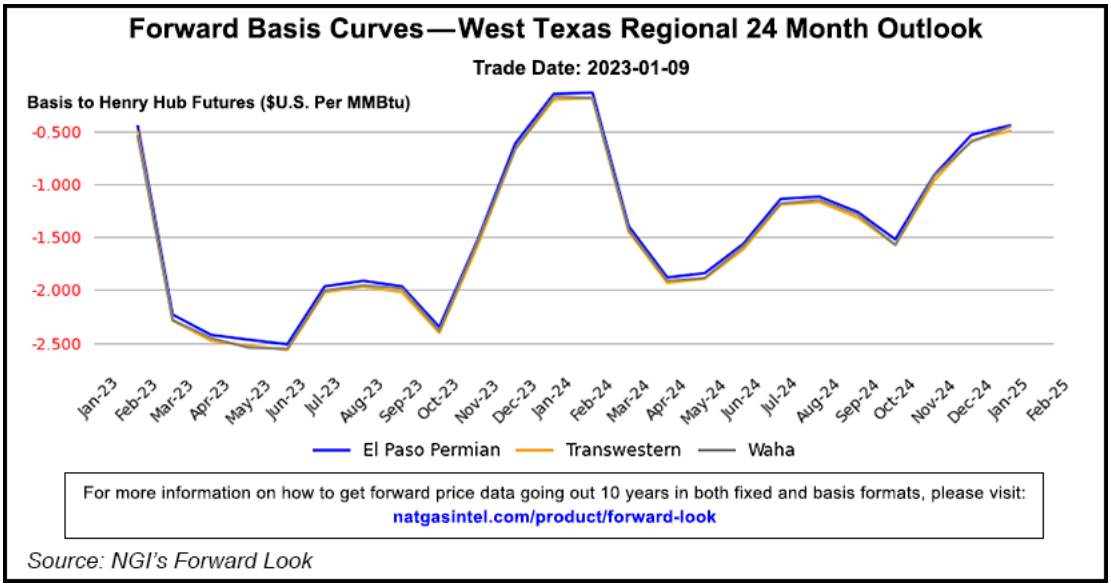

Source: NGI's Forward Look

Hoy, however, said the AGA's outlook shows natural gas demand enduring for decades. Without more infrastructure to both deliver more gas to domestic markets and to move fuel to the Gulf of Mexico for export, the United States could struggle to meet energy needs at home as well as a string of future LNG facilities expected to launch later this decade.

"We have the gas, but we do have serious concerns about having the needed infrastructure to get it where it needs to go," Hoy said.

RBN Energy LLC CEO Rusty Braziel shares those concerns, though he is optimistic that needed infrastructure will get developed in the wake of Russia's war and its unintended effect of amplifying the importance of natural gas – specifically U.S. gas.

RBN expects Lower 48 year-on-year dry gas production to increase by up to 5-7 Bcf/d in 2023.

"Where will all that incremental gas go, assuming power generation is already taking a lot of supply and exports will max out? The answer is…inventories," Braziel said. "And as inventories build, that will most likely translate to lower prices versus 2022."

However, he added, "for you gas bulls out there, don't get too down in the dumps. Starting in 2024, new LNG export capacity starts to ramp up, potentially turning into a torrent over the coming years. Can production growth keep up with all that LNG export capacity? Probably so. But it will be touch and go in some years, with little chance of gas market oversupply conditions coming back after 2023 for a very long time to come." ■

Kevin Dobbs

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Reshuffling The Deck: An NGI Special Edition

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