MIDSTREAM BUSINESS

OCTOBER 2024

Pipeline Consolidation

Energy Transfer, ONEOK lead the M&A Flow

A SUPPLEMENT TO

Oil and Gas Investor

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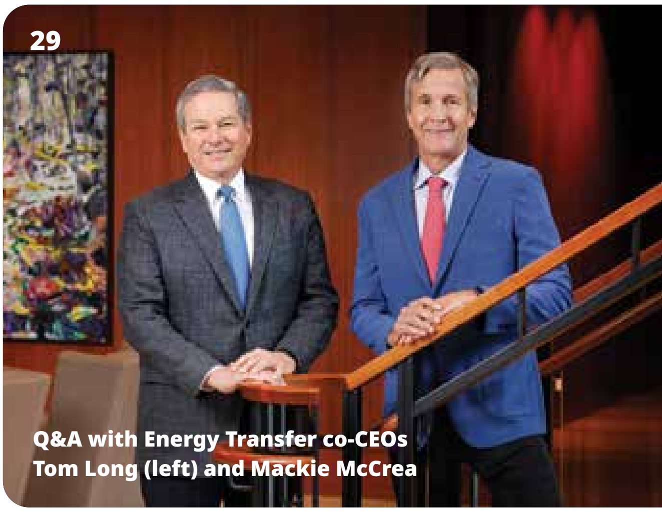

Q&A with Energy Transfer co-CEOs Tom Long (left) and Mackie McCrea

A SUPPLEMENT TO

Oil and Gas Investor

by HARTENERGY

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MIDSTREAM BUSINESS

LETTER FROM THE EDITORIAL DIRECTOR

Midstream Business is Here to Connect the Dots Again

Jordan Blum
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The midstream sector is essentially the business of connecting dots, but those dots are now farther and farther apart as the North American oil and gas sector becomes increasingly global.

The United States is producing record volumes of crude, natural gas and NGL, and they are increasingly feeding international audiences.

That demand requires new long-haul pipelines, more gathering and processing, abundant storage, water infrastructure, massive export terminals, complex LNG liquefaction facilities and much more. This is all occurring amid heightened regulatory and permitting scrutiny, and with greater opposition from non-governmental organizations.

The world may have a better understanding now of the necessity of oil and gas for its energy needs, but that doesn't make building and maintaining the critical infrastructure any easier.

With that in mind, Hart Energy is relaunching its prominent *Midstream Business* magazine as a special publication to tackle all of those issues, as well as the future of the industry. We are publishing one issue this year with multiple editions planned for 2025.

With that future in mind, the midstream space also is getting more involved in carbon capture and sequestration, CO_2 pipelines, green and blue hydrogen projects and more.

For the first time in decades, North America also is set to experience a dramatic uptake in domestic power demand, and that means more natural gas consumption. Some midstream players are investing more in the power space, including gas distribution and even wind and solar power projects.

As for more traditional oil and gas, the industry is building more long-haul pipelines from the booming Permian Basin to port hubs in Texas and Louisiana. The industry trend is to offer more of a full suite of "wellhead to the water" services, and that's leading to more industry consolidation, following the M&A trend of the upstream space.

The sector also is seeing more activity in other basins. There are new rail and pipeline projects from the emerging, waxy Uinta Basin in Utah. The more mature Bakken Shale still needs more capacity and is dealing with NGL conversion projects. The Powder River and Denver-Julesburg basins are gearing up for new growth.

ENBRIDGE

Enbridge President and CEO Greg Ebel visits Enbridge's Keechi wind farm in Jack County, Texas.

The Marcellus Shale finally has the long-delayed Mountain Valley Pipeline project online, but there are many more infrastructure needs within a greatly challenged permitting region. The revitalized Haynesville Shale is adding pipelines and other projects, and wrangling with legal disputes to service global LNG demand.

And, of course, there is a backlog of LNG projects being built, but others still require financing or permitting after the so-called Biden pause. For crude, there is the debate whether existing export terminals will keep growing, or whether any of the pending deepwater crude export hubs will finally be built in the Gulf of Mexico.

This first, relaunched issue of *Midstream Business* features a Q&A with the co-CEOs of Energy Transfer, interviews with the CEOs of Enbridge, Kinetik and many other top players. The magazine features analyses of financing and private equity trends, water infrastructure needs, the future of CCS, the regulatory landscape, pipelines into Mexico, ongoing M&A and much more.

After all, *Midstream Business* is here to help you connect the dots. ■

JORDAN BLUM
EDITORIAL DIRECTOR

OUTLOOK

Electricity and LNG Drive Midstream Growth as M&A Looms

The midstream sector sees surging global and domestic demand with fewer players left to offer 'wellhead to water' services.

JORDAN BLUM, Editorial Director

The U.S. is producing and exporting record volumes of oil, natural gas and NGL with an anticipated surge in domestic power demand from data centers, all of which is expected to require continued midstream infrastructure growth.

The rising domestic demand for natural gas-fired power and for international liquids and gas comes at a time of ongoing industry consolidation and amid a challenging regulatory and permitting environment.

The end result means fewer companies building more pipelines, processing and treatment facilities, storage, and export terminals and LNG facilities while carefully navigating evolving approval processes—much easier said than done.

"The fundamentals are that both oil and gas are still a critical component of any energy policy and of our infrastructure," said Greg Ebel, president and CEO of Enbridge, in an interview with *Midstream Business*. "That wasn't necessarily a popular view a couple of years ago.

"This is about energy evolution," said Ebel, who heads North America's largest midstream player. "As a result, the midstream sector is a critical component. We seem to keep hitting increasingly new records of utilization. It's always a challenging business—all infrastructure is—but we're still building pipes and processing facilities and export facilities at a quicker rate than people are able to do, say, electric transmission lines."

The two big growth drivers right now are electricity and exports, executives and analysts said. And natural gas-fired generation makes up about 45% of all U.S. and North American electricity, necessitating more midstream buildout.

Because more U.S. natural resources are being shipped overseas and because of more associated gas and NGL, especially in the booming Permian Basin, the varying commodities also are more interconnected than ever before, said Rob Wilson, vice president of product for East Daley Analytics.

"There's more need to look at all three commodity streams—gas, crude and NGLs—as opposed to looking at them independently," Wilson said. "You've been able to get away with that, and you can no longer do that.

"We seem to keep hitting increasingly new records of utilization. It's always a challenging business—all infrastructure is—but we're still building pipes and processing facilities and export facilities at a quicker rate than people are able to do, say, electric transmission lines."

GREG EBEL, president and CEO, Enbridge

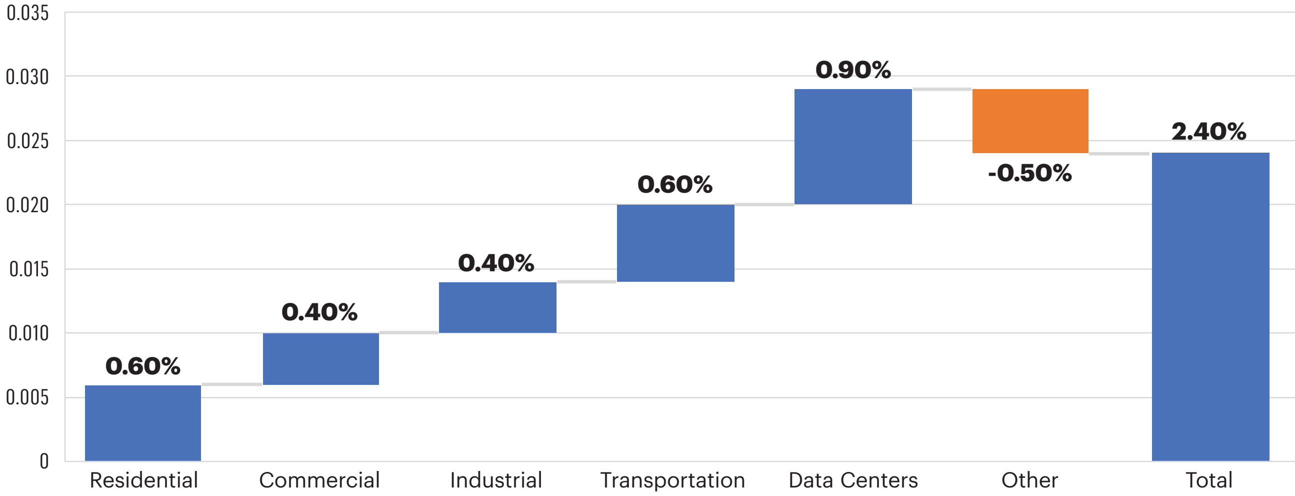
"In almost all three cases, the marginal barrel of growth is almost entirely going to international markets," he continued. "One exception would be with the increase in demand from data centers domestically. But, when you think about gas, we're seeing significant exports of LNG. When you look at ethane, we see a significant amount of activity around exports. We're seeing it with propane. We're seeing it to a lesser degree with crude, but there is still some activity there as far as [adding and expanding] export terminals."

The clearest example is the Waha wackiness in the Permian with the surge in associated gas production, takeaway constraints waiting for the long-haul Matterhorn Pipeline to come online, and exasperation stemming from maintenance downtime with the Permian Highway Pipeline and other systems. The end result has been occasionally negative Waha Hub pricing in West Texas, as well as constrained activity from stranded gas fears.

"Waha is insanely more volatile today than it was two years ago," Wilson said. "That could be a microcosm or somewhat of a canary in the coal mine for what's to happen on a

U.S. Power Demand Growth by Sector

%, 2022-2030

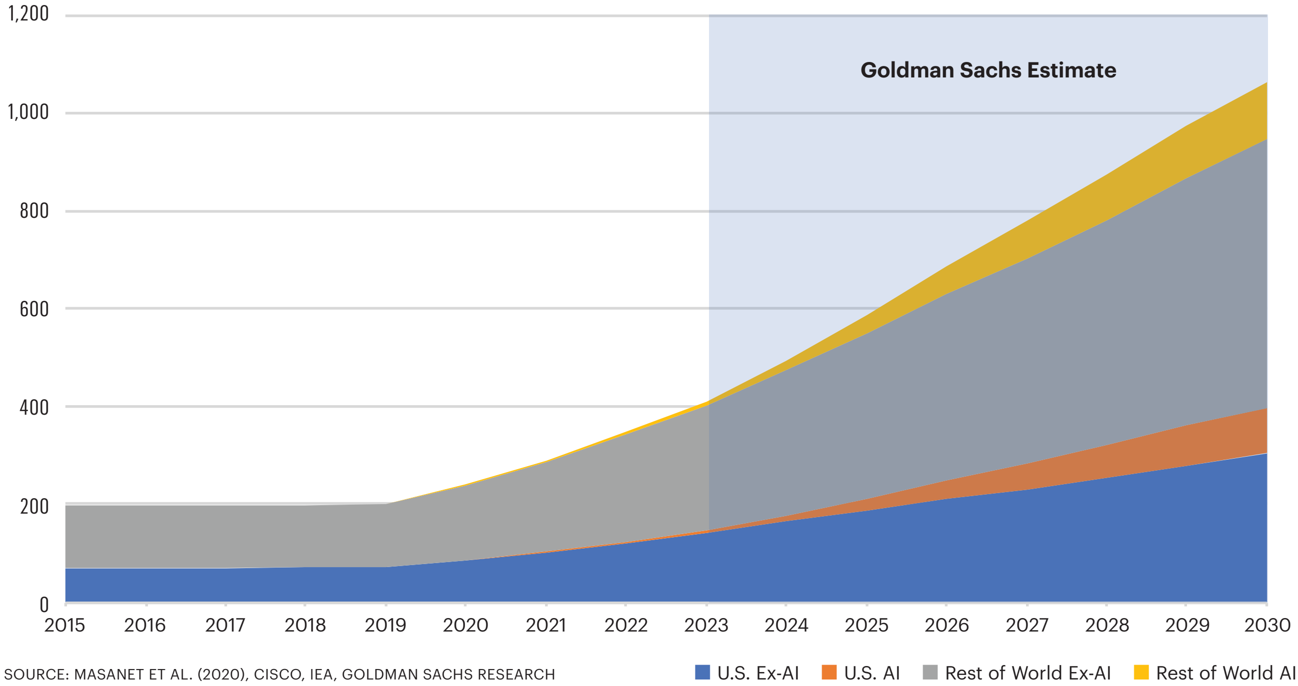


SOURCE: GOLDMAN SACHS RESEARCH, U.S. ENERGY INFORMATION ADMINISTRATION

The demand for electricity is forecast to rise at 2.40% CAGR between 2022 and 2030.

Data Center Power Demand

How the U.S. and the rest of the world compare in data center power demand by AI and non-AI usage in terrawatt hours per year



SOURCE: MASANET ET AL. (2020), CISCO, IEA, GOLDMAN SACHS RESEARCH

broader scale as we open up our markets more and more into international markets.

"It's really those three things: The markets are linked. They're significantly more exposed to growing international demand. And then, the scale of growth will lead to more price volatility."

Gassing Up for More Power

U.S. power demand has held relatively flat for nearly two decades even as the population has grown because of increasing efficiencies from light bulbs and more.

That's set to change now from artificial intelligence (AI) and data center demand and the slow-but-steady electrification of transportation, although by how much is certainly up in the air. Forecasts of domestic demand range from almost 2% to nearly 5% by 2030. Those don't seem like huge numbers, but they represent big jumps in required power generation.

A Goldman Sachs Research report from May projects a

2.4% jump in U.S. power demand between 2022 and 2030, including nearly 1% just from data centers for AI and more—a 165% surge in data center power demand.

The bottom line is this will require a lot more natural gas, regardless of how much more wind, solar and battery power come online.

Also, this anticipated spike comes during the same timeframe when U.S. LNG export capacity is expected to almost double. That's a lot more U.S. gas being consumed domestically and abroad.

"It's just astronomically taken off. It is a bit surprising how fast that's gone," said Sital Mody, president of Kinder Morgan's natural gas pipeline group. "There's discussion across the board on where to site [data] facilities. We're having more discussions directly with data centers themselves, utilities, power providers."

"It's early in the process," he added. "We absolutely are trying to see how the ultimate market is going to evolve. We do know the demand is there. They're looking for clean power, but the reality is how you get that 24/7 reliability. Natural gas is going to have to be part of the story."

New power and LNG demand will both come online in chunks and not always as quickly as anticipated. More pipelines, gas storage and transmission infrastructure will all be needed, and some aspects will be easier than others, which will all contribute to temporary volatility.

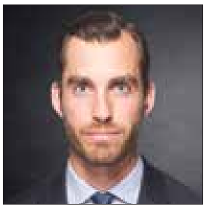
The midstream sector is set to benefit, especially those with strong gas footprints, Mody said. But it won't be seamless.

"If everyone is calling on their capacity and you have a need, then you don't have enough pipeline capacity. That's really going to come to manifest itself sooner as all this LNG demand comes on here in the next year or so," Mody said. "You're going to see the volatility. We expect to see it. These aren't predictions. This is kind of how we see the market coming together at a macro level."

Ebel thinks a lot of prognosticators are underestimating the challenges for permitting and building new electric transmission from state to state.

"I have no doubt that the power demand is going to come. The question is how quickly is that? That's why companies like ours and others in the midstream sector are careful how they do this," Ebel said. "It's about three years in the best jurisdictions to get an interconnect for electric transmission, and the laggards would run six, seven years to get interconnected. If that's the case, then it's going to take a little bit of time for all these data centers to actually get access to the power they need."

This emphasis is partly why Enbridge recently spent $14 billion to dramatically expand its gas utility business by acquiring the East Ohio Gas Co., Questar Gas and the Public Service Company of North Carolina—all from Dominion Energy.



"Waha is insanely more volatile today than it was two years ago. That could be a microcosm or somewhat of a canary in the coal mine for what's to happen on a broader scale as we open up our markets more and more into international markets."

ROB WILSON, vice president of product, East Daley Analytics

In the meantime, the immediate emphasis is on expanding gas takeaway capacity from the Permian. The 2.5 Bcf/d Matterhorn Pipeline to Houston is now online and slowly ramping up, which alleviates a lot of woes.

Kinder Morgan is strongly weighing an expansion of its Gulf Coast Express Pipeline (GCX) from the Permian to the Texas hub in Agua Dulce near Corpus Christi.

"GCX, from a timeline standpoint, has probably a little advantage in terms of how fast it can get to market given the nature that it's just compression expansion," Mody said. "But there is absolutely the need for a pipe, too."

That new pipe is coming in the form of the recently announced Blackcomb Pipeline, which would come online by the end of 2026, carrying 2.5 Bcf/d 365 miles from the Permian to Agua Dulce.

The WhiteWater Midstream-operated Blackcomb project also involves MPLX, Targa Resources and Enbridge, the latter of which owns a 13.3% stake.

"All these projects are competitive, so they stay in the quiet zone until you're confident you've got contracts signed up and you can move forward," Ebel said, praising the joint venture and the pipeline project. "It's exactly the kind of thing that we were looking for."

WhiteWater and its partners also teamed up earlier this year with Enbridge for the initial JV that aimed to connect the Whistler Pipeline from the Permian with Enbridge's Rio Bravo Pipeline project that would stretch from Agua Dulce to NextDecade's Rio Grande LNG project in Brownsville at the southern tip of Texas along the Gulf of Mexico and the Mexican border. Blackcomb is designed to take a similar route to Whistler.

And Energy Transfer is still pushing forward with its proposed Warrior Pipeline from the Permian to East Texas, which, if built, would carry at least 1.5 Bcf/d to the Fort Worth region, potentially serving different markets.

Of course, building long-haul pipelines is more challenging than ever. It's nigh impossible on the East Coast—the recently completed Mountain Valley Pipeline took a decade to finally cross the finish line. But they're not even easy to build in Texas, as recently shown by Kinder Morgan overcoming multiple right of way and eminent domain legal challenges in the Texas Hill Country for its now-operating Permian Highway Pipeline.

"Realistically, you can't take shortcuts in your planning process. You need to reach out to all the stakeholders. You need to be reasonable," Mody said. "Ultimately, when folks aren't reasonable, you've just got to let the process play out and you've got to be patient. You can't overcommit to something without thinking through all the consequences.

"I think our legal and regulatory teams are some of the finest in the industry. How many challenges did we have? We had 14 challenges, and each one of them we overcame legally."

Overall, Jamie Welch, president and CEO of Kinetik, is bullish but realistic on natural gas demand and building more infrastructure amid his gathering and processing empire in the Permian's Delaware Basin.

"We've seen significant growth on the generation side. We're seeing it going through the LNG side. And that's obviously expected to continue. I remain constructive on gas," Welch said. "I do not think gas is a $5/MMBtu commodity. I think we have such an abundance of gas that we will remain $3 or $4, and that's OK, and I think everyone wins."

Processing Problems

Kinetik has quickly grown into the top Permian midstream pure play through mergers and organic growth.

So, Welch is both long-term optimistic but temporarily frustrated with Waha Hub pricing, takeaway issues, and stunted demand from more mild winter and summer seasons.

"We've never seen Waha this bad for this long. It's bad," Welch said. "It has significant negative economic value, and the duration that this has remained has, I think, stunned producers. They just don't know what to do, because no one quite saw this."

Granted, the still-young Kinetik has a nearly $3 billion market cap, earned $109 million in second-quarter net income, and recently acquired the Durango Permian gathering and processing assets in New Mexico for $765 million.

But Welch sees challenges—as well as opportunities—ahead in the Permian.

"I think processing remains tight, treating is very tight. As we continue to see different zones exploited by our customers—in those which have greater ranges of gas quality—that treating and blending is really critical and are areas that have for a long time been overlooked," he said. "You can agree to something by contract, and you can build something that's slightly different where you think it should be, but you couldn't accommodate 5% CO_2."

Kinetik is focusing on moving gas out of New Mexico, especially Lea County, where there are more elevated levels of CO_2 coming out of the production. "We've been a net beneficiary while others have struggled, and that means gas has been diverted our way versus going to other gathering and processing companies," Welch said.

One thing that is catching the industry off guard is the different grades of gas coming out of the more exploratory benches in the Delaware, he said. Kinetik and others are rushing to quickly adapt and take advantage.

"When you look at Lea County and the preponderance of the development and drilling activity there, you've got a lot of Avalon [Shale] and Third Bone Spring that have much, much higher levels of CO_2," Welch said. "We discover these things as we go. There is no wonderful blueprint. We basically roll along with it, and we learn from the process of discovery. The process of discovery is the most important element in the midstream evolution. We understand what we're seeing, and then we adapt. I think that's sort of underestimated."

"I remain constructive on gas. I do not think gas is a $5/MMBtu commodity. I think we have such an abundance of gas that we will remain $3 or $4, and that's OK, and I think everyone wins."

JAMIE WELCH,
president and CEO, Kinetik

Likewise, there are more challenges with a lot of Permian gas and higher nitrogen levels that make processing and liquefaction more cumbersome.

"One key issue on the LNG side is nitrogen. How are we going to handle that as we move forward?" Mody said. "From an infrastructure standpoint, how do you handle the nitrogen needs of the LNG facilities, given the high concentration of nitrogen out of the Permian?"

That also means building more gas infrastructure out of the Eagle Ford and Haynesville shale plays to continue serving the surging—if briefly slowed—LNG demand.

As such, Kinder Morgan is building the Evangeline Pass expansion project in Louisiana for Venture Global's Plaquemines LNG project. And there are the pending Texas Louisiana Expansion and the South System Expansion 4 pipeline and processing projects moving Texas gas to LNG hubs.

"You're going to need all the basins to meet the demand here," Mody said.

Kinder Morgan also is moving more gas to Mexico for planned West Coast LNG, and to the western U.S. to serve growing domestic demand and anticipated data centers. Kinder Morgan's SFPP East Line open season would ship more natural gas from West Texas to Arizona.

Newer processing plants can extract more ethane from the production stream. That has contributed to more NGL conversions along the midstream systems. Enterprise Products Partners recently converted its Seminole Red Pipeline to NGL service from the Permian.

Likewise, in the Bakken, Kinder Morgan is now switching its Double H Pipeline from crude oil to NGL service. In North Dakota, this is related to growing gas-to-oil ratios (GORs) in the Bakken, Mody said.

"This is another example of us looking at the macro and seeing an opportunity to help our producers extract incremental value on their side by not having a limitation on the NGL side," Mody said. "I think you'd be surprised by the GORs. The need for NGL and gas is probably going to go up more than the existing infrastructure out there, even after these expansions."

While most of the crude midstream buildout already occurred in the Permian and Bakken in previous years, East Daley analysts warned that crude constraints could return sooner than anticipated in the coming years.

"Where the market might be overlooking things a little bit is on the crude side," said Ajay Bakshani, East Daley director of energy analytics. "We have Permian crude egress tightening and, as far as liquids go, things tend to tighten up out of nowhere. It's an area the market still hasn't paid much attention to in a while.

"There's a couple of capacity expansions that I think could still be on the table, but I wouldn't be surprised if we see another [crude] long haul as well."

In August, Enbridge announced the 120,000 bbl/d expansion to its Gray Oak Pipeline. Gray Oak is the 850-mile crude long haul connecting the Permian to Enbridge's Ingleside Energy Center, which is the largest crude oil storage and export terminal by volume in the U.S.

Enbridge also is exploring more capacity expansions along its massive Mainline network stretching from the Canadian oil sands down to the Texas Gulf Coast.

"We're in discussion about additional pipeline capacity coming in around 2027 for our Canadian customers that are either trying to get to refineries in the United States or getting all the way to the Gulf," Ebel said.

Meanwhile, the Double H project could inadvertently trigger some crude egress issues from the Bakken, Bakshani said, who noted that Energy Transfer's major artery, the Dakota Access Pipeline (DAPL), is almost 90% utilized.

"If you asked a year ago if that was going to be the case, I probably would've said no," Bakshani said of DAPL. "But now that pipe might be full, and we're seeing a surge in Bakken production as well. There are going to be infrastructure issues across most commodities."

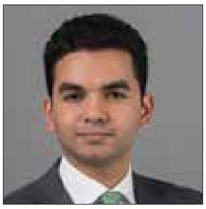
There are crude activity upticks in Wyoming's Powder River Basin and in Utah's waxy Uinta Basin that need more takeaway capacity, too, he said. And it's not just for oil. Kinder Morgan, for instance, just pushed forward with the $263 million Altamont Green River Pipeline project in the Uinta for additional gas egress.

Financing some of these major pipeline projects can be difficult. But one solution is the growing trend of more and larger JVs to finance them, such as with the new Matterhorn, Blackcomb and Rio Bravo projects.

And JVs can invariably lead to more dealmaking, especially in a midstream sector that needs more consolidation to thrive, according to East Daley.

After record-breaking periods of ongoing upstream M&A, the midstream sector is getting busy, too.

"We're still very much in a consolidating period right now," said Wilson of East Daley. "I think that has another 18 to 24 months to it."



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AJAY BAKSHANI, director of energy analytics, East Daley Analytics

Consolidation Concentration

As with the E&Ps, the midstream space is consolidating with a very Permian-centric mindset. But the dealmaking is not West Texas exclusive, either.

Greenfield pipelines are harder to build, making existing pipe in the ground more valuable and ensuring that acquisitions represent the strongest growth option. The trend seems to be for the biggest pipeliners to buy up more gathering and processing players to provide more full-service offerings to their customers.

The big buzz phrase now is "from the wellhead to the water." As Ebel said, "It's being able to competitively put a full path from where the product is produced to actually where it's ultimately being either shipped offshore or being used in the country."

"We've definitely seen the maturation of midstream companies," Wilson said, adding that the industry is essentially in the middle of an acquire-or-be-acquired spree. "If you don't own the full value chain going forward, your long-term strategy is in question,"

The biggest names remain Enbridge, Enterprise, Energy Transfer, Phillips 66, MPLX, Kinder Morgan, Williams Cos., Targa and ONEOK—the latter three of which have especially seen their market cap values soar of late. Anyone else, including even some of the aforementioned, could be scooped up, Wilson and Bakshani said.

"There's a lot of decent-sized Permian G&P systems that are available," Bakshani said. "We're looking at when they were invested in, when these PE companies are probably trying to exit, which is about now. So that's mostly in the Permian.

"I think one of the drivers is going to be on the G&P side and capturing that barrel at the wellhead."

Some of the recent deals include Energy Transfer buying Lotus Midstream, Crestwood Equity Partners and WTG Midstream. Energy Transfer's Sunoco also acquired NuStar Energy.

Otherwise, Enterprise is buying Piñon Midstream in the Permian, Phillips 66 is acquiring Pinnacle Midstream, ONEOK is scooping up Magellan Midstream and more NGL assets from Easton Energy, and upstream gas leader EQT is rolling up Equitrans Midstream.

The latest massive move involves ONEOK buying up a controlling stake in EnLink Midstream for $3.3 billion and a 100% purchase of private Permian player Medallion Midstream for $2.6 billion in cash. The $5.9 billion in combined deals are both with Global Infrastructure Partners, which is selling Medallion and its large EnLink stake.

The most obvious publicly traded acquisition targets remaining, Bakshani and Wilson said, are Western Midstream and, yes, Kinetik, even though it just expanded with the Durango deal. As a side note, producer Occidental Petroleum owns a large chunk of Western, and Oxy is eyeing divestments. Oxy recently sold some Western units for about $700 million.

Kinetik's Welch is not blind to that portrayal. In fact, he embraces it.

"We're pragmatists. We'll continue to be a catalyst for growth—whether it's organic or it's acquisitive—until such time as we are no longer tasked with that role, and we are now just being swept up by a much larger competitor," Welch said. "I think the realization we have is that time is finite and that we won't be around too long, and then we will fit into someone else's plans.

"I think the need for consolidation remains because it creates capital discipline as we've seen. On the customer side, it's important to have that growing capital access and scale on the midstream side. That's just the reality. That's just an evolution of the market. They realize the multiple services that larger companies can offer—the wellhead-to-water opportunities."

Kinetik has grown rapidly—it was created through the combination of EagleClaw Midstream and Altus Midstream—but not in comparison to the three Es—Enbridge, Enterprise and Energy Transfer.

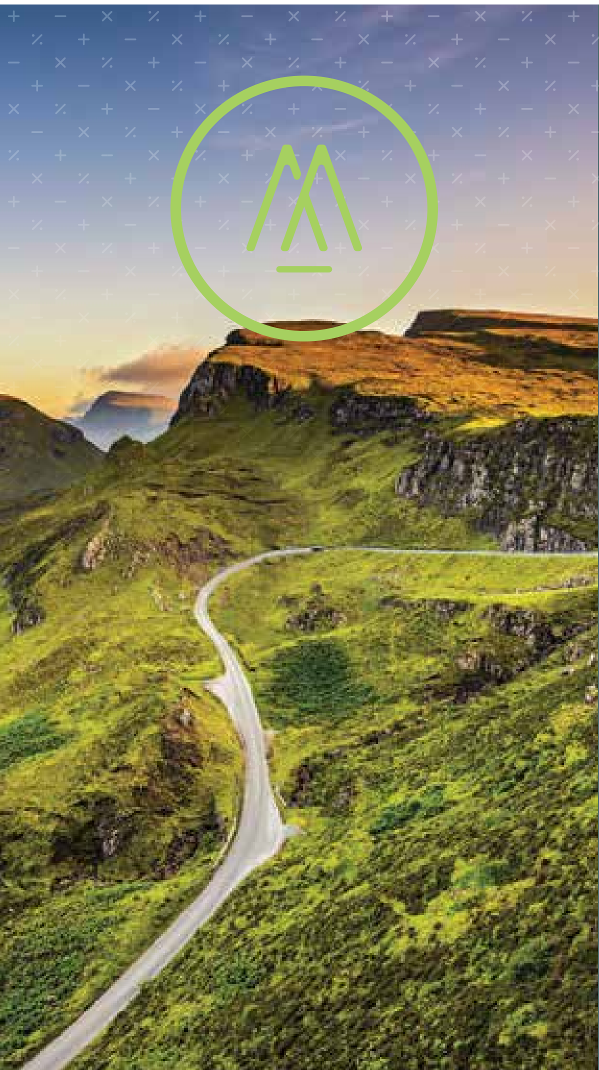
"We are literally a minnow; we are like fish food," Welch said. "We're going to continue doing what we're doing until we're told to stop, and that's all you can do."

But Welch agrees that the private players also will go the way of the dinosaurs. The end of an era is on the horizon.

"The midstream sector remains probably in just about the healthiest place it ever has because balance sheets are much improved, leverage ratios are down, there's much more discipline on distribution growth, and there's not the proliferation of lots of new management teams and lots of new IPO vehicles or public companies," Welch said. "There are fewer customers, there are fewer real impactful basins, and there will be fewer competitors on the midstream side, and that's just a fact of life."

The private players can grow, but only in the short term because they lack the necessary growth capital. And the public producers are reticent to contract with them when they could be "here today, gone tomorrow," Welch said.

The bottom line: "I think all of these private companies are going to be gone in two years." ■



WATER MANAGEMENT

Finding Solutions in Unconventional Plays

How the industry is addressing the challenges and opportunities surrounding produced water.

SANDY SEGRIST, SENIOR EDITOR, GAS AND MIDSTREAM

Steve Coffee finds it ironic that an industry so reliant on hydraulic fracturing is just beginning to give water management the attention it deserves.

"Very few oil and gas companies have a water team or even a water person," said Coffee, president of the Produced Water Society. "It's hard to manage something if you don't even have a person or small team responsible for it."

According to API, the average fracking job uses about 4 million gallons of water per well, and that poses challenges. As the industry has grown, the infrastructure and logistics necessary to provide and dispose of millions of gallons of water for a single well—often in areas where supplies are scarce—have become more and more complicated. At the same time, the public is becoming more concerned about water supply and pollution, and the possible connection between reinjected water and seismic activity.

For the companies involved in midstream water management, current conditions mean a lot of opportunities are on the table.

Midstream water, once considered part of the oilfield services industry, is now a separate industry within the upstream space, according to an analysis released by Mercer Capital in May.

"Very few oil and gas companies have a water team or even a water person. It's hard to manage something if you don't even have a person or small team responsible for it."

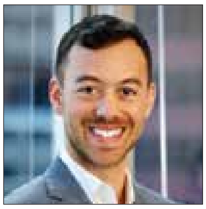
STEVE COFFEE, president, Produced Water Society

"Water management went from being kind of fringe and an issue that people would talk about like, 'Ah, it's so annoying' to being table stakes," said Kelly Bennett, co-founder and CEO of B3 Insight, a water midstream analytics firm.

"Now, if you don't have a viable water management strategy, if you can't understand where that's going over the next X number of years, you do not have a viable company," Bennett said.

A steel pipe drains suspension fluid into a hydraulic dump as part of the process to separate effluents for reuse of water in a closed cycle.

SHUTTERSTOCK



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KELLY BENNETT, co-founder and CEO, B3 Insight

Crossing Streams

Although the midstream water sector has expanded rapidly in the 2020s, it is still growing into the role of a major energy industry player. According to a Mercer Capital report, there are only two pure-play public participants in the market, Aris Water Solutions and NGL Energy Partners, and although the midstream water segment has not seen significant M&A, growth dynamics are favorable for more acquisitions.

In May, Aris reported 15% growth year-over-year and an EBITDA of $53 million in the first quarter. The company is working with ConocoPhillips, Chevron and Exxon Mobil on a desalination pilot project that is scheduled for completion at the end of September. In June, NGL Energy Partners Water Solutions reported a record full-year adjusted EBITDA of $508.3 million, a 10% increase over the prior year.

During investor conference calls, both companies discussed the potential for expansion through M&A, and both said they were cautious about being too aggressive in the market.

Aris Founder and Executive Chairman Bill Zartler explained why the company is not pursuing an acquisition at present. "As this water industry has evolved and developed, the way businesses have grown has been very different in approaches around contracting and around building assets," he said. "And so, we're very careful in evaluating and valuing bolt-on acquisitions. We do think there's some synergies there."

Zartler said the Delaware Basin has a "tremendous opportunity" for growth, but because the water midstream industry includes a very diverse set of players, easy add-ons can be difficult to find.

NGL CFO and Executive Vice President Brad Cooper said his company is focused on its own projects.

Above-ground storage tank used to filter and treat water coming from active wells at a facility near Big Lake, Texas. The scale of hydraulic fracturing in the Permian led producers to develop an extensive network of water pipelines to cut trucking costs and move water more effectively.

"I think there'll be a time for M&A here in the future," Cooper said. "But as Doug (White, executive vice president of NGL Water Solutions) continues to bring the returns he's bringing, we're going to deploy capital to (the organic projects) to the extent we can ahead of M&A."

One of the factors limiting consolidation of water midstream companies, according to the Mercer Capital report, is that E&Ps prefer a market with a multitude of options for bringing in, using and disposing of produced water. A major consolidation would most likely take away avenues of supply and disposal for a product that producers either need quickly or need to dispose of quickly.

A History of Fossil Water

Supply and disposal have been the primary drivers for change in the sector.

Expanding operations have changed things, but when the fracking revolution began, a lot of producers had a single option—themselves.

Although the total amount of water used for fracking varies by basin, an enormous amount of water is required in the Permian, which is the nation's most productive play. The basin has been the focus of the U.S. water midstream development because of the volume of water used and the fact that the region is a desert where average rainfall is less than 20 in per year.

Operators in the Permian Basin, as it became the unconventional production leader, were concerned primarily with getting enough water to drill. Around the 2010s, however, some companies took a more active role in addressing the problem of produced water disposal.

Fracking water contains chemicals and other materials and can bring additional impurities to surface when it comes back up. Water that is left untreated can be toxic and is no longer usable.

Initially, producers pumped produced water into subsurface formations. Though this process sometimes is referred to as "storage," Coffee explained that the term is a misnomer because it implies the water will be extracted again at some point. "It's pouring it down a drain in the ground," he said. "You're not going to be able to use it again."

Seismic activity in basins across the U.S. surged along with the uptick in fracking. Although tying earthquakes directly to fracking activity is difficult—as the exact location and reason for a seismic event is hard to determine—several scientific studies have linked an increase in seismic events with well injections. Oklahoma, which had measured few earthquakes in the years prior, recorded more than 800 events with a magnitude of 3.0 or greater in 2016.

According to Bennett, the thought in the late 2010s was that deeper injection wells, often twice the depth of the earlier wells, would cut the seismic activity and provide more room for disposal.

"So all of a sudden, you have the ability to take way more water in these facilities. They may be significantly more expensive, but they seem like perhaps they're a better reliable,

CANADIAN NATURAL RESOURCES

Produced water recycling facility at Jackfish oil sands field in Canada. While the percentage of reused produced water is growing, many companies are turning their focus to midstream for water management.

long-term solution" he said.

With the introduction of deep wells, seismic activity diminished, at least temporarily.

Meanwhile, the scale of activity in the Permian led producers to develop an extensive network of water pipelines to cut trucking costs and move water more effectively. At the same time, technological advancements allowed lower quality water to be used in the fracking process, allowing for greater reuse, rising to around 10% to 15% before the end of the decade.

Same Problems, Different Times

The percentage of reused produced water continues to grow, but with the current scale of fracking activity, particularly in West Texas and New Mexico, focus has shifted to water midstream. A New York Times article in the latter part of 2023 addressed the growing demand for completions and the threat that poses to the region's aquifers. Politico discussed the same issue in June.

Meanwhile, earthquakes have become prevalent again in West Texas. On July 26, a 5.1 magnitude quake was reported in Hermleigh, Texas, a small town in Scurry County. The event was felt nearly 100 miles to the northwest in Lubbock and 250 miles east in Dallas.

In Coffee's opinion, the focus on water usage could be helpful in the long run.

"More attention, probably, is what is needed to move the dial," he said. "Really most of the reporting isn't thorough enough, or it's just one little slice. How do you write this big novel in 500 words?"

Governments are also taking a more active role. Colorado legislators ordered the creation of a research committee to study potential uses for produced water. In May, New Mexico revealed a draft of new prohibitions for discharging liquid into waterways or using it for agriculture, and provides a path toward more industrial usage. Texas has also been reviewing rules, potentially allowing for agricultural uses and possibly discharge in dry riverbeds.

Companies in oil and gas also are looking for solutions, Bennett said, but he thinks the industry does not get enough credit for the active role it is taking in dealing with its problems. He pointed as an example to an industry initiative called the Texas Produced Water Consortium. The program operates under the administrative oversight of Texas Tech University in coordination with the Government Agency Advisory Council and the Stakeholder Advisory Council.

"One thing that's been pretty remarkable and very unprecedented, that the industry maybe doesn't get enough credit for, is the incredible mobilization of research and science capital to fund it," Bennett said. "It's all focused on understanding this issue. It's a huge amount of operational coordination to get the data that were needed to contribute to the scientific community, the academic community and to the industry itself to better democratize the understanding of what's actually happening here." ■

Finding a Private Niche

Smaller, non-publicly owned midstream companies are moving quickly for a position in a consolidation-driven market.

SANDY SEGRIST, Senior Editor, Gas and Midstream

Private midstream companies are concentrated in the gathering and processing (G&P) sector of the business, which makes that segment especially attractive for acquisition to public companies. According to East Daley Analytics (EDA), the G&P sector accounts for almost half the revenue of a shipped barrel of NGL. By taking over a G&P system and connecting it to its network, a major midstream company can essentially double its earnings.

Public companies spent about $13.5 billion in acquisitions on private G&P networks from 2022 to 2024, according to EDA. The majority of those deals, about $11.2 billion worth, took place in the Permian Basin, the nation's largest producing shale play. EDA data over the last two years show the multiples offered by Permian acquisitions averaged 7.29, while other basins offered an average multiple of 6.3.

"These systems are not just in an attractive basin, but they are competing very well within that basin," said Ajay Bakshani, director of midstream equity at East Daley. "All of the Permian G&P deals had expansions ongoing during the time of acquisition."

The last large acquisition in the Permian, Energy Transfer's merger with WTG Midstream in May 2024, marked a turning point in the basin with the $3.1 billion acquisition of the last, large private G&P network in the basin. WTG's facilities, which touched 25 counties in West Texas, included more than 1 Bcf/d of natural gas processing capacity and had more than 10 rigs operating in the system.

On its own, WTG's system was the seventh-largest G&P network in the basin. With the acquisition of WTG, 82% of the Permian's processing capacity is now owned by eight public midstream companies, according to EDA. Of the remaining midstream G&P networks, 10% is made up of small public and government systems, small private companies with little activity, or small systems owned by E&Ps. The remaining 8% of market share is split among five private companies: Brazos Midstream, Vaquero Midstream, Stakeholder Midstream, Salt Creek Midstream and Canes Midstream.

"These systems are not just in an attractive basin, but they are competing very well within that basin. All of the Permian G&P deals had expansions ongoing during the time of acquisition."

—AJAY BAKSHANI, director of midstream equity, East Daley Analytics

While the pool of remaining private targets continues to shrink, Canes CEO and Co-Founder Scott Brown said the basin still has room to grow.

"It's the best rock in the country, and they continue to find more benches to drill in more economical wells than anywhere else in the U.S.," Brown said.

Private G&P Transactions

Date Announced	Target	Basin/Play	Acquirer	Purchase Price ($MM)	Payment Type	Forward Yr. EBITDA	Est. EV/EBITDA	Capacity at Acquisition (MMcf/d)	Expansions FID'd/ Completed	Expansion ISD
May-24	WTG Midstream	Permian	Energy Transfer	$3,075	Cash & Equity	$356	8.64x	1,300	400	3Q24, 3Q25
May-24	Pinnacle Midstream	Permian	Phillips 66	$550	Cash	$79	7.00x	220	220	2Q25
May-24	Durango Midstream	Permian	Kinetik	$765	Cash & Equity	$139	5.50x	220	200	2Q25
Nov-23	Cureton	DJ	Williams	$560	Cash	$81	6.91x	109	0	
Nov-23	Rocky Mtn. Midstream (50%)	DJ	Williams	$714	Cash	$101	7.07x	460	0	
Sep-23	Meritage	PRB	Western	$885	Cash	$161	5.50x	380	0	
Jul-22	Lucid	Permian	Targa	$3,550	Cash	$473	7.50x	1,400	230	2Q24
Jan-22	Navitas	Permian	Enterprise	$3,250	Cash	$489	6.65x	1,010	900	2023-2025
			Aggregate	$13,349		$1,879	7.11x	5,099	1,950	
			Aggregate Permian	$11,190		$1,536	7.29x	4,150	1,950	
			Aggregate Non-Permian	$2,159		$343	6.30x	949	0	

SOURCE: EAST DALEY ANALYTICS

Canes Midstream's Section 8 Compressor Station in Irion County, Texas. Canes operates 42 compressor stations in the Midland Basin.

CANES MIDSTREAM

"Generally, that's the way to get your foot in the door and start building a grassroots system, is having some kind of niche. For us, when we started building our system, we gave our producers take-in-kind rights for NGLs and residue."

—**SCOTT BROWN,** CEO and co-founder, Canes Midstream

Canes, formed in 2019, operates a G&P system made up primarily of natural gas facilities, with some crude lines in the eastern Midland Basin. The company gained a foothold by offering producers a financial advantage to buy into the system.

"Generally, that's the way to get your foot in the door and start building a grassroots system, is having some kind of niche," Brown said. "For us, when we started building our system, we gave our producers take-in-kind rights for NGLs and residue."

Take-in-kind rights allow producers to market a product themselves instead of depending on the midstream network's downstream contracts.

"As a small private equity startup, you have to be able to customize your agreements with the producers," Brown said. Canes will handle about 600 MMcf/d of natural gas by year-end 2024.

Local Guide

Outside of the Permian, private company Elevation Midstream has been able to differentiate itself to E&Ps by taking on the challenges that the Colorado regulatory regime presents. Plays in this region often are in populated areas and governed by Colorado's state regulators, which API calls "the strictest in the world."

The company operates gas, crude and water lines in the Denver-Julesburg (D-J) Basin, and far from being put off, Elevation CEO John Roberts believes companies willing to take on those challenges can find plenty of prospects.

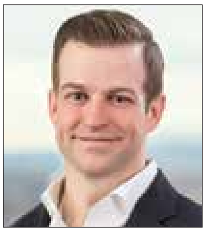
"One of the reasons that we like the D-J is because of the specific complexities from being in Colorado," Roberts said. "There's a perceived overhang due to the complexities of permitting and some of the hurdles of operating here. That tends to keep a lid on competition, which is good for us."

In Colorado, Roberts said, every township and county has its own set of rules, not to mention the state's rigorous legal framework and the occasional hostile politician. The legislature considered a bill in the spring to cease issuing new oil and gas drilling permits by 2030. (The proposal was shot down in committee.)

"Producers, because they have to jump through the same hoops, really know how valuable it is to partner with a midstream operator who understands the complex state, local permitting and all the regulatory regimes and how people can work through all that to get pipe built and their wells connected," Roberts said.

"There's an opportunity here to build a valuable business by targeting a niche spot in the market, both geographically and in terms of where we are in the value chain and doing the hard things well in that niche," he said.

Elevation's operations include crude stabilization capacity of 50,000 bbl/d and 120 MMcf/d of natural gas compression. In July, the company made an acquisition of its own, merging with Platte River Holdings, a subsidiary of ARB Midstream.



"There's a perceived overhang due to the complexities of permitting and some of the hurdles of operating [in Colorado]. That tends to keep a lid on competition, which is good for us."

JOHN ROBERTS, CEO, Elevation Midstream

The Platte River assets added more than 200 miles of crude gathering and transmission pipelines to Elevation's network.

The merger was an indication that the market forces driving consolidation among the larger public companies are at work at the private level as well. The D-J Basin is largely built out, Roberts said, and all companies are looking at other networks for growth opportunities.

"I don't think we're seeing the level of upstream growth in the D-J or anywhere that you used to see," he said. "Those large system buildouts, the large capex spends—that phase is over."

Many senior executives seem to be taking the same approach, exploiting their agility to become experts in an area with a service deficit in preparation for expansion when the right time comes. But not every company is on the bandwagon.

Tallgrass Energy Partners, a public company that went private in 2020, is the exception to the rule with its all-purpose business model. The company operates more than 10,000 miles of energy infrastructure assets across the U.S.

After the Sell

Travis Roby, CEO of Bayou Midstream, which operated out of the Bakken Shale in North Dakota and Montana, said his company's participation in the latest round of midstream M&A is complete as of May with the sale of assets to fellow private company Bridger Pipeline.

Bayou started out in 2018 with 10,000 dedicated acres of crude gathering service for one producer. By 2024, the company had branched out to 90,000 acres and an average flow of 80,000 bbl/d of crude. Bayou's operations even included a sand terminal, which Roby said was a first for him.

"We view ourselves as a midstream company, as a customer service provider for producers," Roby said. "So, we find—or the producers identify—needs they have, and we go solve those needs, or we plug those holes where they have them."

When it came time to sell Bayou's assets, Roby said there was no crystal ball or formula that enabled the companies to decide on the right time.

Bayou had expanded with a merger in 2022, purchasing Northstar Acids. The commercialization of the new assets had gone well, and the company began to receive unsolicited inbounds on its network as the Bakken continued to develop.

"We were in our fifth year," Roby said. "It just seemed like a really good time. It also felt like the window for acquisition was open. Sometimes if feels like there are windows when acquisitions are actually taking place, and there are times when they're not."

The company's crew was either hired full-time by Bridger or kept on as contract workers after the merger. According to Roby, Bayou will probably no longer exist as an entity after this year, but the leadership team is already planning for the next step. Roby and his partner Ross Lairson are once again in negotiations with EIV about starting up another iteration of Bayou.

A Project to Sell

Edmund Knolle, former vice president of business development for Crestwood Midstream Partners and currently the commercial lead for Gulf Coast Midstream Partners, has been working on the business from the other side.

Gulf Coast Midstream Partners, based in Freeport, Texas, is a project company seeking to build the first natural gas storage salt dome on the Gulf Coast in more than a decade.

According to the U.S. Energy Information Administration, salt dome storage capacity in the U.S. has been flat, at 700 Bcf since 2012.

Knolle said demand for salt dome storage has returned to the same levels as in the early 2000s, and the economics are there for construction. This led to the decision that the time was right to pursue a major storage project in the area as LNG export production ramps up over the next few years. The project's appeal to potential customers will be its reliability, he said.

"As a storage person, I think about reliability all the time," Knolle said, pointing to the natural gas supply problems that hit the Houston area in the aftermath of Hurricane Beryl in July.

"There have been a lot of transactions involving existing storage companies in the last few years, but the large public pipeline companies typically are not developers of greenfield storage and haven't been for many decades," he said.

Gulf Coast Midstream Partners applied to the Texas Railroad Commission for a permit to build early in the 2024. Currently, Knolle is seeking to contract with an anchor shipper for the project and then will begin efforts to secure financing.

Knolle said he is optimistic about filling a gap in demand.

More Opportunities Ahead

According to Bakshani, consolidation is the major mover of the energy business today. However, midstream companies will continue to find opportunities as basins build out and move into undeveloped areas as shifts in demand continue.

For industry veteran Roby, the sector remains attractive.

"What drove me into the midstream business was the sense that we are constantly building and developing to keep up with our producer counterparts. Whereas producers have all of their development happening below the surface, I love to be able to visually see it. Building pipelines, building terminals, building processing facilities—there's a visual component to that where you actually get to see the fruit of your labor," Roby said. ■

EXECUTIVE ROUNDTABLE

Private Midstream Executives: More M&A, More Demand, More Gas Pricing Woes

CEOs discuss growth, opportunities and the challenges that lie ahead.

JORDAN BLUM, Editorial Director

Midstream consolidation is ongoing as the biggest public players scoop up smaller pipeliners, but midsized and regional private players still play a significant role in the industry.

CEOs of three of the private players—Howard Energy Partners, Medallion Midstream and Momentum Midstream—recently shared their views on the current status and future needs of the pipeline industry with Midstream Business.

Howard, the largest and most diversified of the three, is big in West Texas, South Texas and Oklahoma, and operates the 200-mile Nueva Era gas pipeline in Mexico. The outlier position is the company's gas-gathering system in the Marcellus Shale.

Howard is in a partnership with Devon Energy for gas gathering and processing systems in the Permian Basin, and operates gas pipelines and processing systems in the Eagle Ford Shale that connect to Mexico and the U.S. Gulf Coast. The company manages Texas hubs for pipeline, marine and rail logistics in Corpus Christi and Port Arthur and operates the Javelina processing facility in Corpus Christi.

Howard Chairman and CEO Mike Howard has led the business since he co-founded it in 2011. Ownership has shifted since then, with the Alberta Investment Management Corp. buying up an 87% stake in Howard by the end of 2022.

Since this interview, Medallion Midstream agreed to a $2.6 billion cash sale to ONEOK.

Medallion works exclusively in the Permian Basin, with integrated midstream services in both the Midland and Delaware lobes of the basin. President and CEO Randy Lentz joined Medallion in 2010.

Global Infrastructure Partners-backed Medallion has a massive Midland Basin footprint, with 1,200 miles of pipeline and gathering systems as well as 1.5 MMbbl of storage. Its smaller Texas Southern Delaware assets include more than 130 miles of crude pipeline in Ward, Pecos and Crane counties and more than 100,000 bbl of storage.

The focus for Momentum Midstream is its large gathering and processing network in the Haynesville Shale. Following acquisitions two years ago from Midcoast Energy and Align Midstream, a large portion of its assets are on the East Texas side of the border. Momentum also has significant gas delivery to LNG hubs along the Texas and Louisiana Gulf Coast.

The company has developed or acquired more than 5,000 miles of pipeline, 18 processing facilities and three NGL fractionation facilities over the past 20 years, and has more than 1 MMbbl of storage with roughly 500,000 hp of compression.

Momentum co-founder and CEO Frank Tsuru has been in his role since the company's inception in 2004. Backed by EnCap Flatrock, Momentum also is supported by Yorktown Partners, Ridgemont Equity Partners and Blackstone Credit.

Howard, Lentz and Tsuru discussed the state of the midstream sector with Jordan Blum, Hart Energy's editorial director.

Jordan Blum: On the macro level, how do you see the overall state of the midstream sector in North America, especially U.S. shale?

Mike Howard: Howard Energy is one of the largest, private midstream companies in the U.S. We are in a unique position with strong capital backing from a pension fund, and we have not used the traditional build-and-flip private equity model. We have a very long-term outlook versus the quarter-to-quarter mindset of the publicly traded market.

So, as an investment, we like natural gas-related infrastructure, and we like NGL and refined product infrastructure. We see short-term growth in shale natural gas—besides the Permian, which is associated gas tied to oil prices—to be challenged due to low natural gas prices and a lack of new infrastructure needs until natural gas drilling picks up. We believe there is still some consolidation in the market since a midstream IPO has not been a great option for private companies since 2015, and mid-tier public companies have shown to have a hard time growing to meet investors' expectations.

Randy Lentz: Overall, the state of the midstream sector is very strong and stable. As producers continue to consolidate and direct their capital to the highest-return basins, midstream companies will do the same and continue to invest

"Bad energy policy in Texas and the United States is what keeps me up at night. Over the last several years, we have come to appreciate the need for energy advocacy and the role all energy employees can play in this space."

MIKE HOWARD, chairman and CEO, Howard Energy

"The midstream sector is in an extremely healthy position. Since 2020, we've seen a significant improvement in public company valuations with these companies strengthening their balance sheets. The financial health of the sector bodes well for future M&A activity."

FRANK TSURU, co-founder and CEO, Momentum Midstream

"The M&A trends are showing that the best basins continue to be the best basins, and the onset of technological advancements to unlock production and inventory is the reason there has been so much M&A activity as of late."

RANDY LENTZ, president and CEO, Medallion Midstream

in growth opportunities as volumes in these basins increase.

Frank Tsuru: The midstream sector is in an extremely healthy position. Since 2020, we've seen a significant improvement in public company valuations with these companies strengthening their balance sheets. The financial health of the sector bodes well for future M&A activity. At Momentum, we're focused on natural gas.

Yes, the market is currently oversupplied, partly due to an unusually warm winter. But let's not lose sight of the bigger picture. The structural support is there, driven by the strong demand growth in Gulf Coast LNG and the power sector and, finally, the fuel switching of power plants from coal to clean-burning natural gas. Renewables will certainly supplement power growth, but the supply and runtime certainty provided by natural gas-fired turbines will remain essential. We continue to see the Haynesville as the primary gas-supply basin to meet this growing demand, thanks to its superior rock quality, proximity to key demand centers, and an accommodating regulatory framework in Texas and Louisiana.

JB: How do you see midstream consolidation continuing to play out for the industry, especially amid all of the upstream M&A?
RL: In the near term, it will likely continue, especially in the basins where the largest upstream M&A consolidation is occurring. Larger [publics] will acquire smaller private companies or possibly look at mergers or JV opportunities with other [publics] to capture more synergies.

JB: As the numbers of major midstream companies shrink through M&A, what kind of an effect does that have on the private companies? And what advice would you give to someone starting their own private midstream business?
MH: Our advice to someone looking to start their own private midstream company is simply, don't. It's too hard.

All kidding aside, if you must, picking a basin and figuring out the infrastructure needs in that area are key. We have

HOWARD ENERGY PARTNERS

Howard Energy Partners' Nueva Era Pipeline nears the Rio Grande outside Laredo, Texas. The Nueva Era Pipeline connects Eagle Ford Shale gas to the industrial center of Monterrey, Mexico. Chairman and CEO Mike Howard believes more infrastructure in this area is needed to keep up with current demand.

also found that, like any other business, relationships are everything. If you can prove that you can execute better than others while remaining relationship-oriented, you will beat out the competition. Capital is the other major factor. Finding the deal first, then the capital to back it may not be the easiest approach—and often requires patience—but is more beneficial in the long run.

We experienced the creation of multiple private midstream companies in the late 2000s with the shale boom. Given the private company exits and consolidations that have occurred, there is an opportunity for smaller companies to thrive, even though access to capital is much more difficult these days. At Howard Energy, we built a business around projects that require moving at speed and cost structures that bigger companies often don't pursue. We punch above our weight in sophistication and project execution as well, which makes us well suited to providing services to large customers. We have the unique ability to figure out the infrastructure gaps that need to be filled and work quickly to address them.

RL: Private midstream companies with good assets in good basins will continue to have options. While there could be fewer exit opportunities, scarcity value could become real as large publics run out of acquisition targets.

Starting a new private midstream business in the near term will be challenging, given the lack of new basins and the infrastructure maturity of existing basins. However, there could be acquisition opportunities down the road. As companies grow, it is much harder to maintain efficiencies, and ultimately, non-strategic assets will be on the market.

JB: Are there any trends you see emerging from the M&A deals that have happened recently?

RL: The M&A trends are showing that the best basins continue to be the best basins, and the onset of technological advancements to unlock production and inventory is the reason there has been so much M&A activity as of late.

JB: What are the primary needs for the industry in terms of infrastructure gaps, growing demand, etc.?

RL: Significant increases in natural gas production will continue to drive infrastructure in the form of additional gas processing facilities and NGL and residue takeaway pipelines. Additional LNG facilities or expansions also will be needed to provide a market for supply growth.

FT: North American LNG exports are set to nearly double by the end of the decade, with most of this growth coming from Louisiana and Texas. This expansion could require over 20 Bcf/d of additional supply, and as I mentioned earlier, the Haynesville will be a key source for Gulf Coast LNG. Pipeline expansions are already underway, including our NG3 gathering system, which can provide up to 2.2 Bcf/d

MEDALLION MIDSTREAM

Medallion Midstream has 1,200 miles of pipeline and gathering systems in the Midland Basin, as well as 1.5 MMbbl of storage. Its smaller Texas Southern Delaware assets include more than 130 miles of crude pipeline in Ward, Pecos and Crane counties and more than 100,000 bbl of storage.

of low-carbon feedstock. However, more infrastructure will be needed. I expect another two or three regional pipeline projects from the Haynesville to the Gulf Coast will be necessary to meet the projected growth. The supply and demand will be lumpy as 1.5-2.5 Bcf/d of takeaway capacity will become available every time a new regional pipeline comes on.

We also need to consider the Permian. New intrastate pipelines will connect associated gas production to the coast, but the high nitrogen content of Permian gas presents challenges for the LNG industry. With nitrogen content often twice the preferred LNG specifications, the Haynesville—with its lower nitrogen content—becomes an attractive blend stock. Significant supply growth will require large investments for in-field gathering, CO_2 and H_2S treating, and gas-processing infrastructure. This is especially true as producers push the boundaries of existing plays. We're already seeing this in the Haynesville, particularly in the Shelby Trough and Western Haynesville, where production has potential to overwhelm local infrastructure in the near term.

JB: In the Permian specifically, what are the other top needs? Processing? Long-haul gas? Blending and treating? And what gets overlooked?

RL: The priorities will be gas processing, residue gas and NGL-frac capacity. With robust activity in the Permian, an expansion of crude takeaway capacity also will be needed in 18 to 24 months. What gets overlooked is the in-field gathering—gas, oil and water—infrastructure required to aggregate and deliver Permian production to processing plants or oil long-haul pipelines.

JB: How do you see domestic power demand—especially with the growth of artificial intelligence—impacting the industry? And why? How do you see pricing playing out?

MH: We believe that energy demand and GDP growth are intrinsically linked. The U.S. and Mexico are experiencing energy demand growth of electrification, LNG export, data centers [including AI] and manufacturing. Natural gas is the most reliable, low-carbon and low-cost energy source to meet the increase in this demand. However, our experience is that, in the near term, natural gas supply in the U.S. can far outstrip demand due to our innovative upstream industry. In the free-market environment that we have today, it makes us bullish on energy demand in the U.S. and Mexico and bearish on long-term, five-year natural gas prices.

RL: Power is a long-term challenge for everyone in the industry. As we focus on reducing Scope 1 emissions, power needs through the use of more renewable energy become a bigger part of the algorithm, but the nature of that power availability becomes a large factor, too. More investment is needed in all forms of power generation to meet both demand and manage power costs.

FT: Utilities are investing heavily to support power-demand growth, and the reliability of natural gas makes it a crucial part of the generation mix. Peaker plants are being developed to address the "duck curve" problem created by solar and wind. These plants need callable gas, which can only be provided instantly through access to storage. Baseload plants are being installed to meet the needs of AI and data center growth. This means utilities need firm capacity on long-haul pipelines to reach supply. Gas power plants must be sited near data centers, and while gas infrastructure is important for these decisions, the future availability and cost of pipeline capacity can be a real challenge for utility companies, but that can create opportunity for midstream companies. Increased demand should be beneficial for pricing, with peaker plants leading to increased volatility.

JB: How difficult and frustrating is pricing right now? Not just Henry Hub, but Waha and others?

MH: We have a bearish outlook on long-term natural gas pricing. It has been our experience that the industry can quickly address short-term price dislocations with an increase in supply, which keeps gas prices historically low. This can be frustrating when approached in the short term, but when we look at the long term, natural gas is really the only energy source that can meet the scale and intermittency required in the electricity market. New gas generation installations will help to maintain the reliability of our power grids and support our growing energy demand from technological advances like AI. Through continued innovation, our industry will adapt to the lower-for-longer gas prices like we always have.

JB: What is the potential for greenfield midstream growth, and where is the need greatest?

FT: Over the last five to 10 years, supply-push commitments from producers have helped FID critical infrastructure to link production basins with end markets, particularly Gulf Coast LNG. In the near term, greenfield midstream growth will be demand-pull, driven by utilities and industrials. These sectors have historically been able to procure delivered gas at their plants, but they are now focused on securing supply due to increased competition from LNG and data center demand. Now, they are competing for the same molecules in congested areas like the Mississippi River corridor in Louisiana and Port Arthur and Beaumont in Texas. We believe the Haynesville and Permian are well suited to address these challenges, though it won't happen overnight. These projects require scale and cooperation from different companies with different views on how to fix the problem at hand.

JB: What is the current and future role of midstream in carbon capture and storage, hydrogen and other new energies ventures?

MH: We believe the companies in the midstream business will be a major player in new energy ventures since we have the experience and capital to build industrial infrastructure. As capitalists and a midstream company, we focus on maximizing the return of our investors' dollars by meeting the increased demand for energy and listening to the market's desire for lower-carbon forms of energy. This ability to understand the duality of these focused goals, holding two truths at the same time, is what makes us unique.

Howard Energy Partners, through our Low Carbon Solutions group, has an active project for CCS in the Coastal Bend area of South Texas supported by a DOE [U.S. Department of Energy] grant. We also produce low-carbon-intensive hydrogen at our Javelina facility in Corpus Christi that includes our partnership with E-fuels producer, Infinium. We also own the largest renewable diesel logistics facility in Texas. These and other new energy venture projects will only happen if they make an acceptable return on investment.

FT: Following the sale of M5 Midstream in 2019, we spent quite a bit of time exploring low-carbon and waste-to-fuel projects. Generating acceptable returns and deploying capital at scale was challenging. Our new ventures focus at Momentum is on CCS where it makes economic sense.

Our project currently under construction, NG3, is a great example of how CCS can be economically deployed at scale. We are using 45Q tax credits, which were put in place to encourage midstream investment just like NG3, to provide our customers with a differentiated, cost-competitive gathering and treating solution that is net negative, meaning we will sequester more CO_2 than we emit.

JB: What midstream technological development has excited you the most?

RL: The use of AI in everyday operations and its predictive nature regarding maintenance. It can be a gamechanger.

JB: What current and potential global geopolitical impacts are you watching?

MH: We are specifically focused on energy demand that we can impact, which is Gulf Coast LNG and Mexico. We are experiencing record natural gas and electricity demand in northern Mexico due to the industrial nearshoring from overseas companies.

Our Nueva Era Pipeline connects Eagle Ford Shale gas directly to the industrial center of Monterrey, Mexico. We believe more infrastructure in this area is needed to keep up with current demand. On the LNG front, we watch the growing LNG demand from Cheniere Corpus Christi and the NextDecade facility in Brownsville and look for ways to supply them with the low-nitrogen gas of the Eagle Ford.

JB: What are the things that concern you most about the future of the midstream sector?

MH: Bad energy policy in Texas and the United States is what keeps me up at night. Over the last several years, we have come to appreciate the need for energy advocacy and the role all energy employees can play in this space. The short-term thinking of energy policy—when it should be long-term, multidecade-level thinking—is difficult to overcome and has proven to be an uphill battle with the mounting negative rhetoric. To combat this approach to short-term thinking, we must focus on energy education and encouraging our energy leaders to step up as advocates and policymakers. ■

M&A Trend: Quality Assets in Quality Basins

Canes Midstream CEO Scott Brown believes the Permian Basin still has plenty of runway for growth and development.

SANDY SEGRIST, Senior Editor, Gas and Midstream

Scott Brown started his career in the 1990s as a plant engineer with Warren Petroleum. He worked his way up through the ranks at several energy companies, lastly at Energy Transfer, before he joined Lucid in 2013. After several iterations, the company emerged as Canes Midstream in 2019, with Brown as a founder and CEO. The company, backed by EIV Capital and Trace Capital Management, has operations in the Midland Basin, and according to East Daley Analytics, is considered one of the hotter remaining private operators in the Permian. Brown, who was nominated along with executives of Energy Transfer and Clearfork Midstream in 2023 as midstream executive of the year by D Magazine, sat down with Midstream Business *for an interview in June at the company's Dallas offices.*

SANDY SEGRIST: Let's start with M&A. The midstream market is warming up, and some people are saying it is already boiling over. You have been through several rounds of the process during your career. How is Canes Midstream positioned?

SCOTT BROWN: I personally think Canes is well-positioned. We've got a pretty straightforward business; there are no secrets, no weird things. The timing for us just depends on a number of things we're still trying to accomplish. We've accomplished a lot over the last couple of years, but we've got a handful of other things we're trying to get done. For example, in July, we're going to start up an expansion. It's a relatively small 40 MMcf/d expansion on our processing system. We've got a few others that we want to get accomplished before we think the timing would be right.

SS: From the M&A deals that have been announced publicly so far, have you noticed any trends?

SB: I'm obviously focused more on the midstream M&A deals, but it seems to be that the ones that are transacting are the quality assets in quality basins. I think another trend, really over the last three or more years, [is that] buyers have been a lot more disciplined than they used to be—doing a lot more due diligence, valuing based on existing business that's line of sight versus valuations based on a dream. Another thing I'm seeing are targeted acquisitions. It seems like it's very clear how they fit with the buyer's either current assets or business plan versus just out there buying anything.

SS: Some analysts have said that the Permian is so well developed that there are not a lot of major projects or midstream projects left to develop or grow. Is that more of a concern for the public majors or is it something that private companies also worry about?

SB: It's challenging. I think it's a concern for both publics and privates. With the consolidations, especially in public companies, and [those companies] buying up the private companies, that makes it challenging as well.

What I will say is, the Permian Basin is the basin that just keeps giving. We've been hearing about producers who are testing different benches, specifically in the Midland Basin where we are. It's mostly Wolfcamp A and B, and Lower Spraberry that have been developed, but there's a lot of testing in the Barnett, the Jo Mill, Wolfcamp D, Dean and the Upper and Middle Spraberry.

So, they continue to add benches. It feels like there is a lot of runway for a lot more growth and development. It's just a matter of, "Is it already dedicated?" The question I have is, "Is it just those consolidators that will be doing most of the projects and expanding?"

"I think another [M&A dealmaking] trend, really over the last three or more years, [is that] buyers have been a lot more disciplined than they used to be—doing a lot more due diligence, valuing based on existing business that's line of sight versus valuations based on a dream."

SCOTT BROWN, founder and CEO, Canes Midstream

CANES MIDSTREAM

Canes Midstream's Big Lake Processing Complex in Reagan County, Texas, has a capacity of 440 MMcf/d. The cryogenic gas processing plant handles production from the Wolfcamp Formation in the Midland Basin.

SS: Let's talk about your background. You went from Energy Transfer, one of the biggest publics, to private Lucid in 2013. What attracted you at that point to a private company?

SB: First of all, I've got to say Energy Transfer is a great company. I have a lot of respect for those guys. They've built a great business, and I enjoyed my time there and learned a lot. But yeah, when the opportunity came to go to the private side, it felt like more ownership in the business versus just being one of 1,000 people working in a business. It's really the ownership, and then the opportunity to get involved in every aspect of running a business. When I was fortunate enough to be commercial, it was a lot of fun. I met a lot of producer customers. I got to work on a lot of fun stuff at Energy Transfer. Being in a private equity-backed smaller business, you have to wear a lot of different hats and work on all different aspects of the business, which I enjoy. I'm self-motivated and just like the challenge of doing other stuff.

SS: Was it something you always planned on doing?

SB: You know, I would say, not really. When the opportunity came, I jumped at it, for sure. But it's not something that I had always planned on. I mean, when I was younger, coming out of college with a chemical engineering degree, I thought I'd probably stay with the same company my entire career. Of course, it's a bit of a different world now. I don't know that I would think that coming out of college now. But no, it's something that probably grew on me over time.

SS: You joined Lucid in 2013, then started Canes in 2019. How did things change?

SB: [Lucid] had already been established, and they had a little bit of traction on a project, and that's when they brought me in. And we were fortunate. We were able to grow the company significantly from that point. With Canes, I had to go raise the money, get the equity backing. Then, when we were fortunate enough to be backed, go rent office space, hire a core group of people, set up payroll. I became involved in a whole lot more aspects of the business.

Lucid was already up and running. Canes had its own challenges. We got backed in late September of 2019, and then in March of 2020 everything gets shut down because of COVID. Deals weren't getting done. It was kind of an awkward time for us. Like, "Oh, crap, how is this going to work out?" But I will tell you, our sponsors were very supportive and assured me all along the way that we would have plenty of running room to get a project; It wouldn't be a typical two-year deal, where "you need a project, or we're going to cut your funds."

CANES MIDSTREAM

Canes Midstream's Silver Plant is a gas processing facility in northern Sterling County, Texas.

SS: EIV gave you your funding originally?

SB: It was originally EIV and then, when we brought Cogent [Midstream] in [in 2022], it was Denham [Capital], which is now Trace [Capital].

SS: As one of the founders of Canes, was there a primary idea that you brought with you that you wanted to build the company around a specific aspect of midstream?

SB: Yeah. We were looking at G&P. We looked hard at a crude line. So, we did not specifically know exactly what kind of asset we would end up owning. But whether it was going to be a greenfield or an acquisition, I did want a quality asset in a quality area and a team of individuals with high integrity. It was just very, very important to me. And I'm very grateful and feel very fortunate that I think we've achieved that. We've got a really good asset in one of the best basins in the world, and the team we've got here is really top notch.

SS: You have two primary operations, both in the Midland Basin. You talked a little bit about growing your plant. What's the major goal for the company right now?

SB: We've grown the assets. Just some statistics—the month before we acquired them, they had about 420 MMcf/d on the system. Today, we've got about 550 MMcf/d on the system, and we are going to about 600 MMcf/d. We've got 570 million of processing capacity, and once this 40 million expansion gets in, we will be capable of recovering about 70,000 bbl/d of NGLs.

"We feel like we've got a great asset in a great area. We've got the G&P asset and then we've got a small crude system in Irion County. Our growth will all be on the G&P asset."

SCOTT BROWN, founder and CEO, Canes Midstream

We have looked at some acquisitions that didn't make sense. We ended up not pursuing them really hard. We'll continue to look at other acquisitions, but the primary driver is to continue to grow the business we have. We feel like we've got a great asset in a great area. We've got the G&P asset and then we've got a small crude system in Irion County. Our growth will all be on the G&P asset. ■

CORPORATE STRATEGY

Energy Transfer Leads the Midstream Consolidation Flow

ET co-CEOs discuss pipeline pain points, needed M&A, regulatory woes and much more in a Midstream Business exclusive.

JORDAN BLUM, Editorial Director

Midstream magnate Kelcy Warren handed Energy Transfer's metaphorical baton—or pipe—to right-hand men Mackie McCrea and Tom Long in the height of the pandemic and amid much industry uncertainty after announcing them as co-CEOs in October 2020.

At the time, ET traded at about $6 per unit during the temporary COVID-19 bust. Now it's nearly triple that value as Energy Transfer leads the newest wave of industry consolidation and organic growth in the midstream sector, including its ongoing control of Sunoco and USA Compression Partners.

Fewer than 50 days after taking over, McCrea and Long led the $7.2 billion acquisition of Enable Midstream in early 2021. After a brief hiatus, the $1.5 billion deal for Lotus Midstream followed in 2023, then the $7.1 billion acquisition of Crestwood Equity Partners and, this summer, the $3.25 billion purchase of WTG Midstream.

Earlier this year, Sunoco scooped up NuStar Energy for $7.3 billion. ET-controlled Sunoco promptly joined with Energy Transfer to form a new Permian Basin crude oil and produced water joint venture, utilizing much of those NuStar assets.

And they're not about to stop. McCrea and Long insisted much more midstream M&A is still required, and that ET will continue to stand out as the leader in the consolidation space.

Energy Transfer increasingly has a dominant Permian presence—from gathering and processing systems to long-haul pipe—and strong positions in every key oil and gas basin in the country. ET also continues to grow in the burgeoning liquids and LNG export markets along the Texas-Louisiana Gulf Coast.

Warren, who remains executive chairman, grew ET aggressively from its birth nearly 30 years ago. McCrea joined Energy Transfer nearly from the beginning in 1997 as a senior vice president, working his way up to president and chief commercial officer before taking on the co-CEO role. Long signed on in 2015 and served as CFO for about five years.

The two can balance each other out on the operating and financial sides while leading business strategies together for an empire of more than 130,000 miles of pipeline and associated energy infrastructure spanning 44 states.

McCrea and Long sat down exclusively with Hart Energy's editorial director, Jordan Blum, to discuss Energy Transfer, the state of the industry and changes on the horizon.

Jordan Blum: Starting a little broad, what's your take on the overall state of the midstream sector in North America right now, especially U.S. shale, and, of course, Energy Transfer's role there?

Mackie McCrea: From a macro level, what we see in the midstream industry is a lot of activity. There's cryos [cryogenic gas plants] being built all over the Permian Basin. You've got pipelines being built or brought online in different areas of the United States. And, certainly, if you look at Energy Transfer specifically, we're in that same boat. We've got a lot going on—building new pipe, proposing new pipes, adding export capabilities, adding cryos, etc. So, even despite what's going on from an administration and political standpoint, where we are seeing a very difficult environment, the midstream [industry] is still thriving despite a lot of the hurdles that have been thrown up.

JB: What are the primary needs for the industry right now in terms of infrastructure gaps with growing demand and everything? I'm asking from the long-haul pipelines to whatever needs there are in terms of fractionation, blending and treating, etc., including a lot of the stuff that gets overlooked.

MM: I'll focus on what we're looking at, what our needs are, which of course is in much of the U.S., but I'll start in the Permian. It's probably the most prolific basin in the world from different aspects. There's significant infrastructure needed out of there. There's a lot of cryo being built. We've announced one and, more likely than not in the second half of this year, we'll announce another one or so. We'll see how that goes. In addition to that, there needs to be another [long-haul gas] pipeline. There's a 42-inch pipeline coming online here [Matterhorn Express Pipeline]. We hope that's going to alleviate the pain for producers in the short term.

But we believe, within 18 to 24 months, if not sooner, it's going to get tight again. So, there definitely needs to be more pipe built out of the Permian Basin, and we actually think there needs to be more pipes built in both directions eventually out of the Permian. We believe there also needs to be another pipeline or more pipelines built out of East Texas and North Louisiana to feed into the growth

Energy Transfer co-CEOs Tom Long, left, and Mackie McCrea took the reins of the midstream giant in late 2020 and have since presided over acquisitions totaling more than $26 billion.

TOM FOX

along the Gulf Coast, certainly the LNG growth as well as other growth, and also connecting to pipelines that go more to the Southeast. And, additionally, there needs to be more pipelines built out of the Terryville [Louisiana] area where a lot of the big-inch pipelines come in there, and there needs to be more capacity built to the Southeast.

If you look at just NGLs, there's been some announcements of NGLs coming out of the Permian Basin, and we certainly need to look very closely at what we're going to do with our NGL growth. We already have a lot of growth. We already have a lot of third-party business. We're adding cryos. We'll need to be able to get those NGLs to Mont Belvieu [Texas], and a lot of that on the water. Finishing up, there's a lot of production in this country and it cannot be absorbed and consumed in the United States. There's a dire need for LPG growth and natural gas growth throughout the world. So, there's a significant importance for getting both natural gas and natural gas liquids on the water. We do see a continued growth feeding on what we're already doing for export capacity for NGLs along the Gulf Coast.

JB: Do you see crude oil pipeline capacity as being pretty solid, at least for now compared to greater needs for NGLs and gas?
MM: I think that sums it up very well. You look back around the pandemic times, and then where volumes have grown from there. Oil has kind of consistently grown moderately over the last three or four years, and gas has just taken off. So, we don't really see a need short term for crude oil. Now, there are some rumors out there that there may be some repurposing of some crude pipes. So, there could be some things that happen where all of a sudden there's a need. But, certainly, from our standpoint over the next year or two, we don't see any rush for more crude capacity out of the Permian Basin.

JB: Is Energy Transfer looking at repurposing possibilities?
MM: What I was just referring to is not us, but we have teams that are looking at everything we own that's underutilized. Would it make sense to put it into a different product service? Absolutely. We're always making those analyses and reviews.

JB: Switching gears a little bit and, obviously, you've been very involved in this, but what's your take on how midstream consolidation is unfolding? There's been a big wave of upstream consolidation ongoing and it seems to be coming into midstream now. There's fewer and fewer players with a handful dominating in the three Es—Energy Transfer, Enbridge and Enterprise Products Partners—and then a few others more gas- or NGL-focused in Kinder Morgan, Williams Cos., Targa Resources and ONEOK.
Tom Long: We are very, very excited about the consolidation that's occurring. You can pretty much ask anyone out there when they talk about M&A, and Energy Transfer is going to be the first name that comes up as very, very active in this. Even when it wasn't the popular thing to do, we never stopped talking about it, we never stopped pursuing it, and look where it's gotten us. And now, all of a sudden, it's the thing that the others are trying to play catch-up on. If you go back, not even that long ago to 2010 or so, we were really gas-focused. Then, you just saw us continue to make acquisition after acquisition that now has us in every commodity—not just natural gas, but all the natural gas liquids and the crude oil.

You can also see from a geographic standpoint how we've

Located on the Sabine-Neches Waterway between Beaumont and Port Arthur, Texas, Energy Transfer's Nederland Terminal receives, stores and distributes crude oil, NGLs, feedstocks, petrochemicals and marine vessel fuel for refiners and other large transporters. Energy Transfer is working on the potential Blue Marlin Offshore Port, a deepwater crude export terminal offshore the Nederland Terminal.

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moved all the way to the wellhead and to the water and any markets in between, and also on the international front. I think you're going to continue to see it, and you're going to see that a lot of these were pretty small midstream companies that were started up by private equity firms. You're not seeing private equity firms invest a whole lot more, and you're actually seeing them exit. West Texas Gas [WTG] that we just closed on was a good example of that. We now have the ability to provide the broadest scope of services to the upstream customers. A lot of these others—when they look out and start thinking five, 10 years down the road—they're kind of landlocked, they can't really move upstream a whole lot more, and there's not necessarily a lot more they can do downstream. They usually have to bring the product back to us to get to the markets. It's just not a good place to be.

We've created an unbelievable footprint entity that can participate in pretty much any market and have access to all the major producing basins. You're also seeing what's happening to our [upstream] customers with all the consolidation that's occurring there. So, it makes sense. All in all, this M&A has been very good for the industry, and we feel like we were and still are the leader in the consolidation that's occurring.

JB: Do you feel like you're really strong in where you want to be in basically every basin now? You look at the map, and you're basically everywhere, but is there anywhere you specifically still want to grow?

TL: That is a very commonly asked question. What they tack onto it is how much larger can you get without running into FTC [Federal Trade Commission] issues?

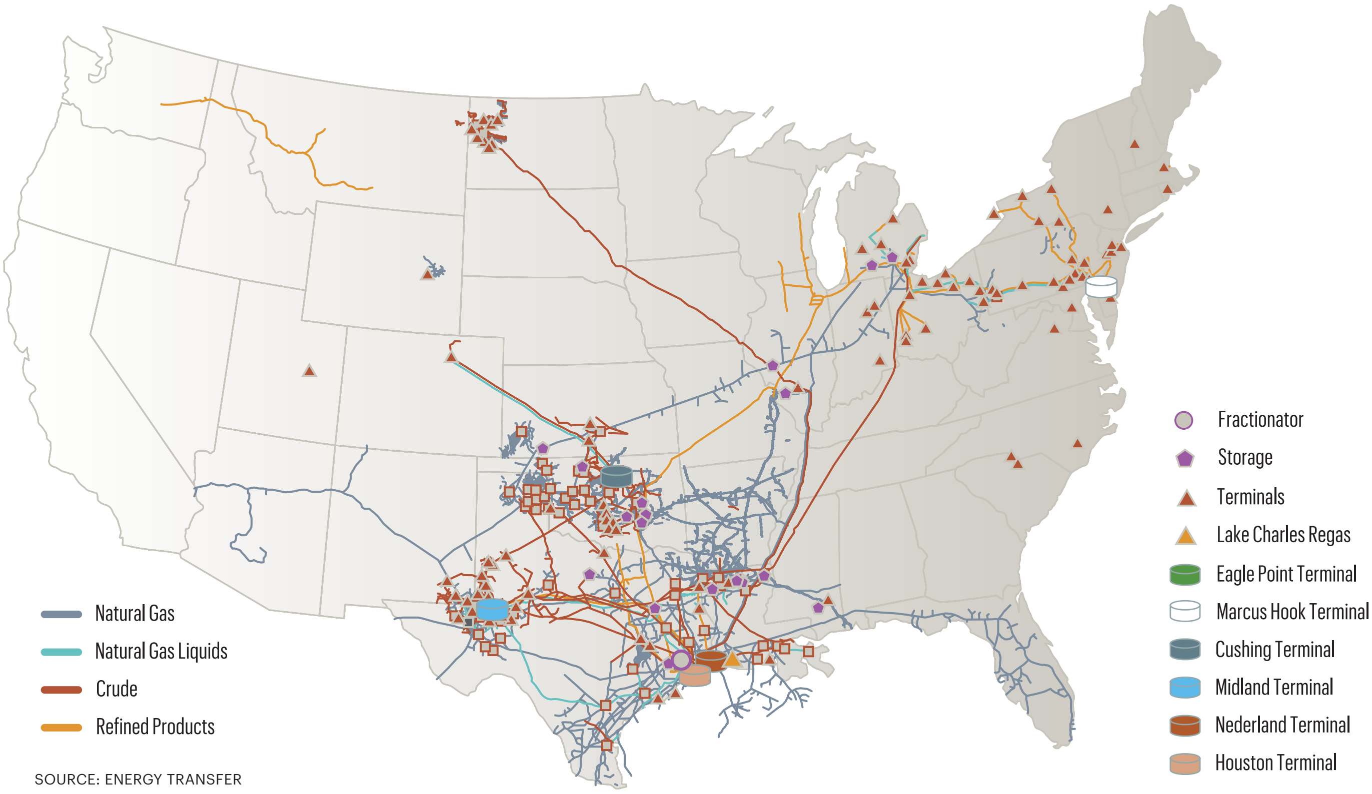
When you look at each one of these basins, we feel that there's still enough competition. We still feel it makes sense as long as you have a few competitors in each area. Remember, we are not just natural gas. We're natural gas liquids and crude oil. So, when you stack this up, you can look just about in any of these basins, and we feel like there's still more we can do that does make sense, and we have no intention of slowing down here.

JB: Delving into WTG, that makes you even stronger in the Midland Basin and farther east. I just wanted to see if I could get you to elaborate on just the fit there, but also for future positioning as Permian producers try to extend those sweet spots in Mitchell County and different areas. Does that position you well for the future as well as the present?

TL: Just continuing with what I was just rolling through, West Texas Gas, Crestwood, Lotus, Enable, those are the more recent ones. When you look at how we go through the process, we first look at a fit and then everything I talked about being in all the commodities and pretty much all the basins. It fits a pretty easy box to check when you really think about it. So now it comes down to if it's accretive on a distributable cash flow per unit. We want to make sure that we're creating value for our stakeholders, for our equity holders. And then the third thing we'll look at is leverage. We want to make sure that we continue to create value for the debt side of our capital structure, meaning that we're bringing leverage down and continuing to strengthen the balance sheet.

Once again, when you participate in all the commodities, it's pretty easy to find a lot of value downstream of these acquisitions we make. A lot of these have been the ones, especially the most recent, that I call more in the gathering and processing side of the equation. We're very excited

Nationwide Footprint



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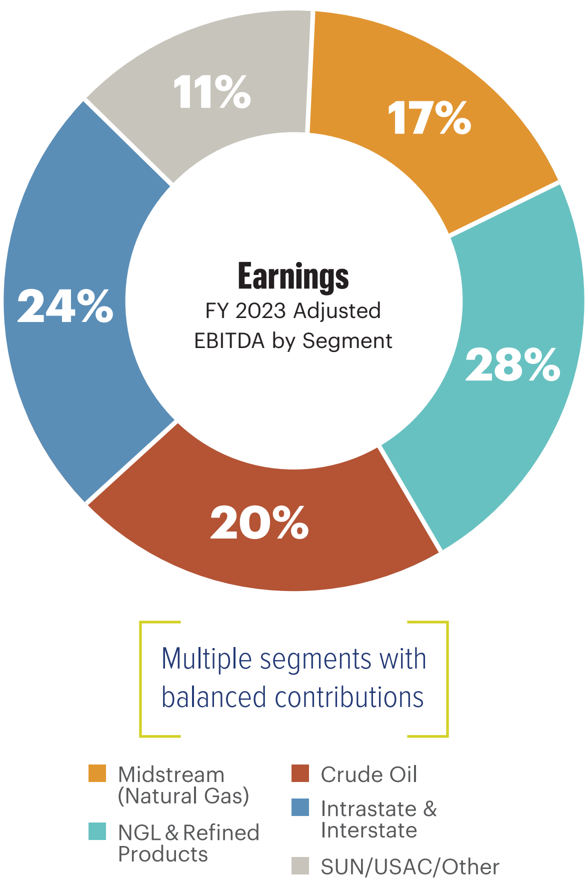

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about these, and they are clearly checking all the boxes.

MM: You look at WTG, you look at Crestwood, you look at Lotus, those were assets and companies that were in dire need of transfer. And what I mean by that, and Tom alluded to it, is they were stuck. They gathered gas, they processed it, and then they gave it to some other parties. Now, we can go to those same producers that are already on the systems and attract new customers and we say, "Where do you want to go? Do you want to go to a power plant? Do you want go across the state with your gas to an LNG facility? Do you want to move your liquids to Mont Belvieu? Do you want your liquids exported?" So, it's that next step from all these assets they couldn't do on their own. We're really able to create some significant savings when we buy these companies, but also significant synergies. They will feed into our NGL network, they'll feed into our intrastate and interstate networks, and they will also help our export projects in a big way.

TL: The way that we will talk to the Street about these is they were starved for capital. They didn't have the balance sheet to do it and yet, talking to their commercial folks, they had a long list of projects that they would've loved to do. That's what we bring to the table. And we are absolutely second to none when it comes to the operations side of it. We've got a formula here that's working, and the market gets it. They see how successful we've been at this and, once again, we're seeing some of our peers stop and take note of this. I think some are going to try a little bit harder to see what they can do, but it's maybe a little too late.

The Mont Belvieu Facility is an integrated liquids storage and fractionation facility located 30 miles east of Houston along the U.S. Gulf Coast. The facility has strategic access to multiple Natural Gas Liquids (NGLs) and refined products pipelines, the Houston Ship Channel trading hub, and numerous chemical plants, refineries and fractionators.

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JB: We talked about WTG. And you mentioned Lotus and Crestwood, which are all strong in the Permian. But Crestwood also has a big Williston Basin presence. What's your take on growth in that region and supporting DAPL [Energy Transfer's Dakota Access Pipeline]?

MM: We're really excited about what's going on up there. With prior acquisitions, we kind of got in the water business. But that [Crestwood] put us in a big way in the water, which is a big deal up in the Bakken. What it's really doing is, and I can't go into the specifics, but it's giving us the opportunity to increase our processing business. When we bought Crestwood, they had assets that were available, but just weren't full. So, we are negotiating, and hopefully finalizing soon, new deals to fill up those cryos. But what we're really doing, too, is gathering more crude to Dakota Access, and we're bringing it to areas where Dakota Access is the outlet. With all the trouble we went through to get that [DAPL] in service, what a great asset that is for us, for our country, for refineries. And we are the dominant player there. Regardless of how much the Bakken may grow, we will see most of that growth because of what we can offer to customers by delivering to the refineries in the Midcontinent or all the way down the Gulf Coast.

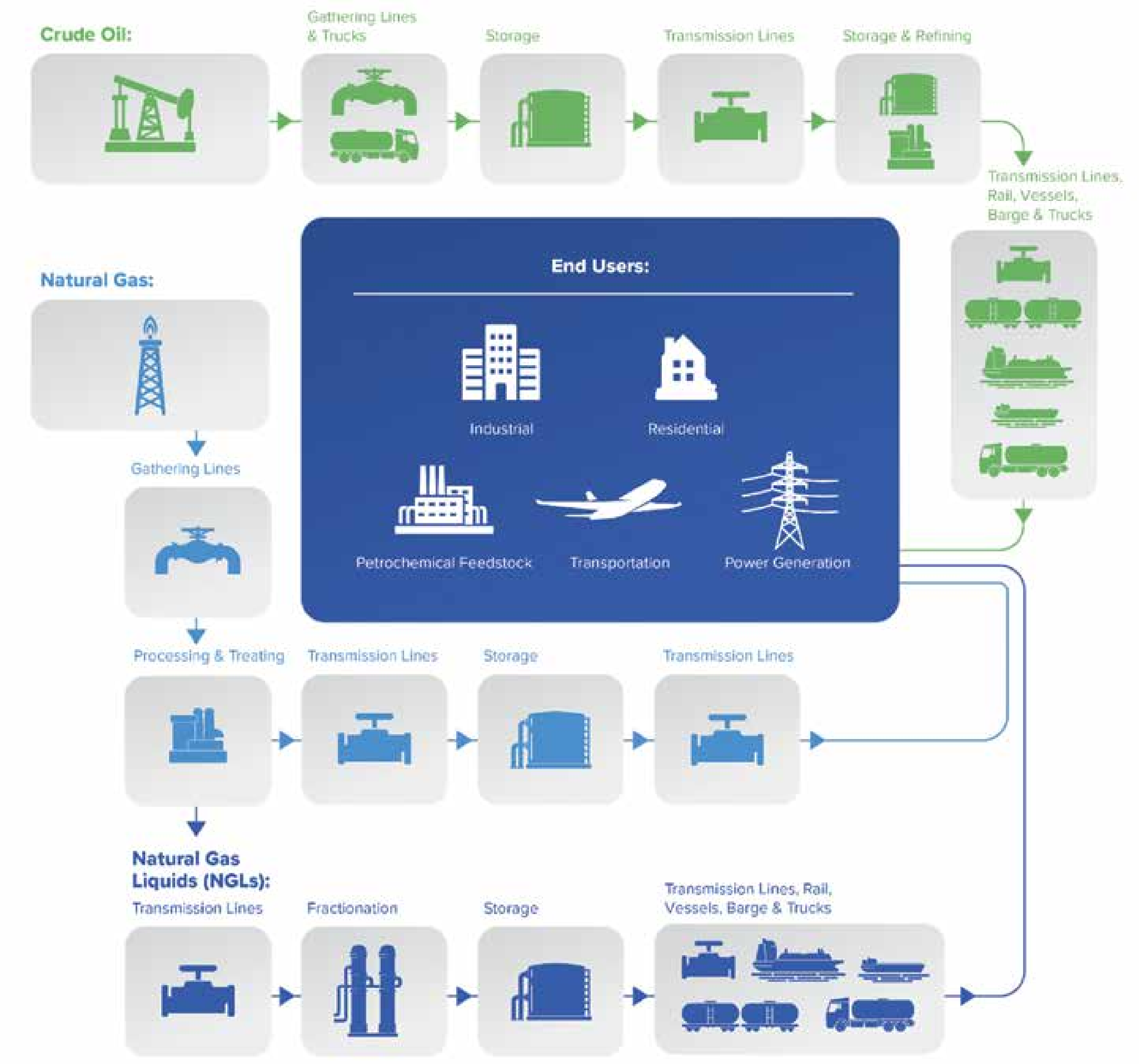
JB: I wanted to bounce around the other basins a little bit, too. Going back about three years, you grew in the Midcon and in the Haynesville Shale with Enable, and you have Gulf Run [Pipeline] online and some other projects. Can I get your thoughts on those basins as well?

MM: You look at a pipeline map, and you've got to get some gas out of Oklahoma or North Louisiana or the Permian or East Texas, and where can you go where one company can do all that? There's only one company that can do that. So, we're very bullish on our position to be able to accommodate whether it's markets along the Gulf Coast or other areas of the U.S., or whether it's producers trying to find the best outlet, most efficient, most profitable outlet for them and they're looking at our assets, and certainly Enable helped that in a big way. That gave us a very good position, a better and stronger position across North Louisiana with the enormous reserves in Haynesville. And then it connected the dots by connecting the Oklahoma assets with our East Texas 42-inch assets that come into Carthage [Texas], with our 42-inch pipelines that come out of Carthage all the way to Terryville, with our Gulf Run that goes down and connects to Golden Pass [LNG], and some other projects that we have planned. So, Enable has been an incredible asset to us that continues to create value that we didn't really even see when we were in the process of acquiring it.

JB: Earlier, you mentioned having pipes go more in both directions from the Permian. I know this is to serve growing domestic power demand and, therefore, natural gas demand for data centers and artificial intelligence. But the focus still remains on heading to the Gulf Coast for bullishness on LNG facilities, even if they're going slower than you'd like.

MM: A lot of stuff that we're working on is early stages and pretty confidential, but I guess it's fair to say the growth is all over the United States for different needs of electricity. Certainly, a lot of

Providing Services from Wellhead to Water



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things are going on, for example, in Arizona around data center growth and power plant demand. There's a need—there's a significant need—for more gas, certainly in California, and they're going to import their stuff, but also more gas in Nevada and more gas in Arizona. So, we do see that as growth potential.

When you talk about natural gas transportation and natural gas delivery, we couldn't feel better about where we sit and where the upside is for our assets. I mean, other than the Eastern Seaboard, there's really no market area that we can't touch with our significant intra- and interstate pipeline system. We're very excited about this so-called transition because what we're transitioning into is a significant need in demand growth for natural gas.

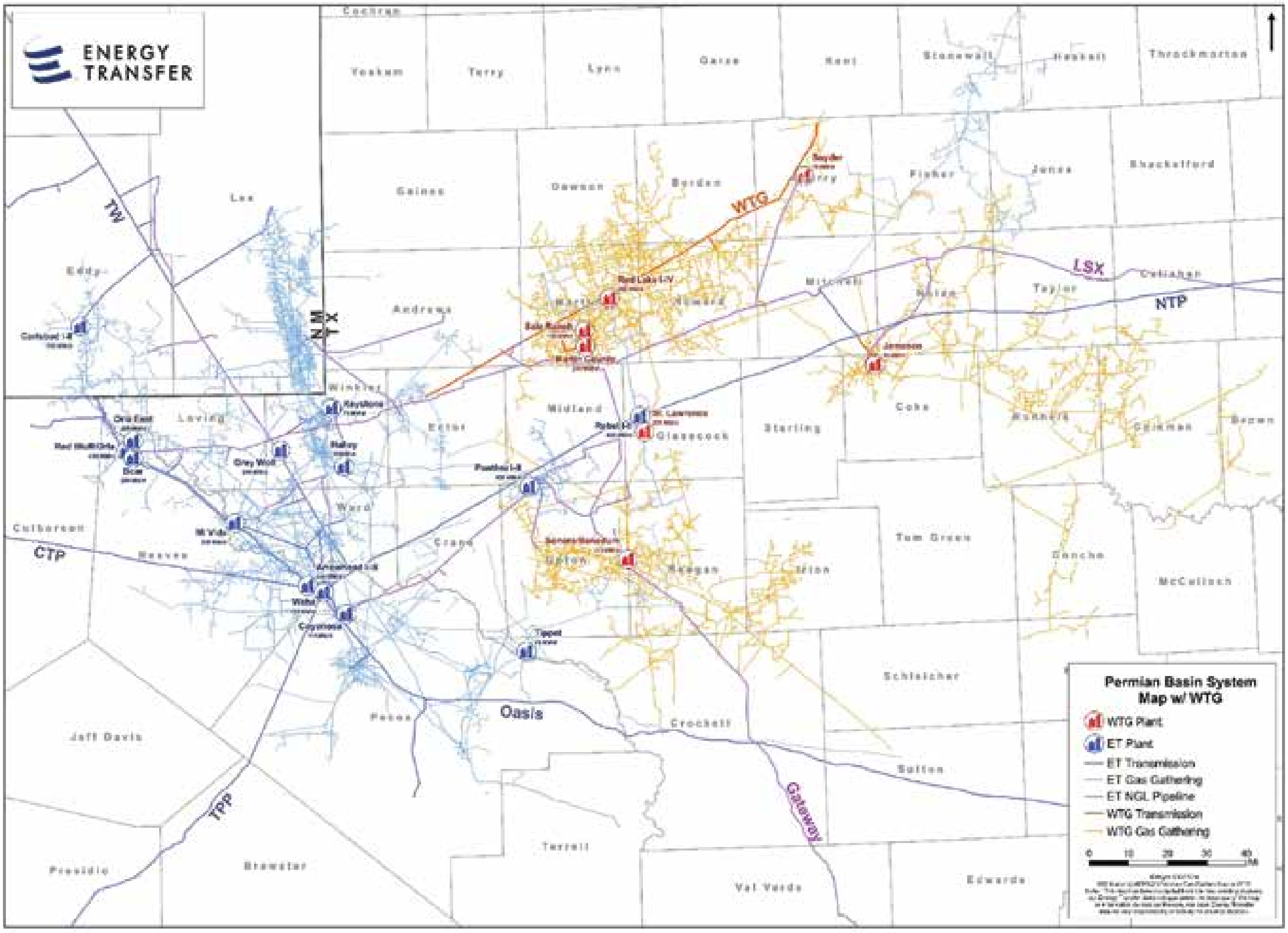
JB: It seems like AI and data centers are going to be huge for the industry even if you're not actually utilizing the AI.

MM: Exactly. Unlike crypto, they can't go down. So, you're not going to run a data center on solar; you're not going to run a data center on wind. You've got to have natural gas.

JB: Obviously, exports are key, including your Nederland [Texas] terminal hub. But I also wanted to get your thoughts on the future of crude exports and where things might stand with the potential for the Blue Marlin Offshore Port [deepwater export terminal offshore of Nederland] down the road.

MM: I've joined our team over in Europe and parts of Asia, and

WTG Transaction Highlights



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it's very clear there is more than enough support to support at least one [deepwater terminal]. And there may only be more than enough support for at least one, and we believe it will be ours. When you look at some of the competition, and there's not a lot out there, they just don't compare in a number of ways. One, they can't easily get as many barrels into their projects as we can to ours. We also are brownfield. This isn't a greenfield project like some of our competitors. The pipe is already laying in the Gulf. It already is going out to a dock to a terminal that we will be upgrading offshore. So, yeah, we've got to build some tanks and build some pipe onshore, but we've got a huge advantage there, and I think the market has recognized that.

We're working hard, we're being very aggressive. This is a big commitment with the size and volumes of projects like this, but they [TotalEnergies and other potential customers] vastly prefer our project. It's brownfield, less expensive, more supply flexibility, just a lot of pluses. We're very optimistic that if a [project] gets to the finish line it will be ours.

JB: It went from a lot of competitors prior to the pandemic to very few, as you said. I don't know if you can elaborate on this, but is it kind of a Blue Marlin versus SPOT [Enterprise's Sea Port Oil Terminal] race at this point?

MM: That's probably pretty fair.

JB: Staying on crude, I was going to ask initially how the Sunoco-NuStar deal factors into the broader ET umbrella, and if you would eventually want to consolidate more with Sunoco. But now you've announced the Permian Basin crude oil joint venture with Sunoco and the NuStar assets, so will you elaborate on that and if that kind of suffices on that front?

MM: We've got a really good relationship and partnership in some areas with Sunoco. This really is one of those deals that we believe is going to be better for the customers because this combined JV approach is going to give them more flexibility, more things to do with their oil. It's also going to be very beneficial to our two partnerships. It really is one of those situations where one and one are going to be a lot more than two, whether it's offering more downstream storage or downstream access to longer-haul pipes and a lot of other things we can do. So, we're very excited about that JV.

JB: Switching back to gas and LNG, obviously LNG should be bullish for you regardless of what happens. And things are on pause a little bit, but can I get you to elaborate on just how things are looking with the FID for the Lake Charles LNG?

ENABLE MIDSTREAM PARTNERS	WEX WOODFORD EXPRESS, LLC	LOTUS MIDSTREAM	Crestwood	WTG
▶ **Closed December 2021** ▶ Assets complementary to ET's interstate and intrastate pipeline system ▶ Increased gathering and processing footprint in the Midcontinent and added complementary U.S. Gulf Coast infrastructure ▶ Anchored by strong customers and fee-based contracts ▶ Immediately accretive to free cash flow and DCF/unit ▶ At announcement, transaction value represented 6.9x multiple of 2021E run-rate EBITDA	▶ **Closed September 2022** ▶ Assets extended ET's gas gathering and processing system in the SCOOP play in OK ▶ Added processing/treating plant and gathering lines directly connected to ET's network ▶ Anchored by strong customers and fee-based with significant acreage dedications contracts ▶ Immediately accretive to free cash flow and DCF/unit	▶ **Closed May 2023** ▶ Assets complementary to ET's crude oil pipeline system ▶ Increased gathering and promisi Basin print in the increased connectivity to major hubs ▶ Anchored by strong customers and fee-based contracts ▶ Immediately accretive to free cash flow and DCF/unit	▶ **Closed November 2023** ▶ Assets enhanced NGL & Refined Products storage and logistics business ▶ Increased gathering and processing footprint in Delaware and Williston Basins ▶ Added entry into the Powder River Basin ▶ Anchored by primarily fixed fee agreements and top-tier customer base ▶ Immediately accretive to DC/unit upon closing	▶ **Closed July 2024** ▶ Expanded natural gas pipeline and processing network in Permian Basin ▶ Expected to add incremental revenue from downstream NGL transport and frac fees ▶ Supported by high-quality customers with an average contract life of 8+ years ▶ Estimated DCF accretion of ~$0.04/common unit in 2025, increasing to ~$0.07/unit in 2027 ▶ At announcement, transaction value represented sub 7x multiple of 2025E run-rate EBITDA

SOURCE: CORPORATE FILINGS

Obviously, you got the FERC [Federal Energy Regulatory Commission] approval, but then there's the time extension issues [denied summer 2023] and you're maybe looking for partners on the project. So where do things stand?

MM: This one has been frustrating to us. Usually, when we set our minds to something, especially significant projects, sooner or later we get there. We still believe we've got a good chance of getting there. We had a lot of momentum. We felt pretty good about how we were proceeding. And then the pandemic hit that brought everything, at least from our standpoint, to a screeching halt. Then we had Russia-Ukraine, and that turned everything 180 in the other direction. We picked back up, had tremendous momentum, had already secured a significant amount of commitments. We're in the process of solidifying enough commitments to get us to FID or close to FID. FERC had extended our permit. We were assured all along the way by the DOE [U.S. Department of Energy] and had no indication whatsoever that they might not extend it even up until about two weeks before they came out and said, "We're not extending it." So that certainly cut our legs out from under us. But the way I would describe it is, we're not slowing down. Right now, we're in negotiations with over 33 million tonnes that have an interest in our project, but they want to know that we're for real, that we're moving forward. So, we're doing everything we can to solidify the commitments from our customers, and to solidify the approximately 75% to 80% equity interest that we need to bring in. Our interest is only keeping about 20% of the LNG facility, but we're continuing to push.

Our goals right now are to keep the EPC [engineering, procurement and construction] iron hot, keep that as fresh as we can and get to the end of this year, see what happens in November [presidential election], and be prepared to go to FID if all these boxes are checked. We've got to get the equity partners, we've got to get the minimum commitments we need, all the supply and everything we need. We hope to be ready to go to FID as soon as maybe another [Trump] administration would approve it fairly promptly sometime maybe in February. So that's our goal. A lot of things can happen. We certainly had a tough road for all the reasons I mentioned. We're not giving up, and we still think we've got a good chance of getting it to FID.

JB: So, a lot is hanging on the GOP winning the White House and the recent U.S. Supreme Court ruling overturning the Chevron deference doctrine that had given more authority to federal agencies, including the DOE?

MM: We feel confident if there's an administrative change, they're not going to come in and say, "Oh, you've got to do this. You've got to do that." They're going to say, "Follow the laws." Whether it's FERC, DOE, SEC, FTC, whatever, follow the laws and we can all play by those rules. We do believe there'll be a sensibility, a reasonableness coming out of the new administration across the board. And that probably means pushing some new folks into the administrative arm of these regulatory agencies to follow the law, not to make a law, but to follow it.

JB: Lastly, I wanted to get your take on MLP trends and having fewer partnership players, and just the viability of that structure going forward?

MM: The MLP structure really was the big driver on the infrastructure buildout that you've seen in the U.S. When we look back on this, you can see how it really changed starting from a little retail investment option and, all of a sudden, the institutionals started moving in and it worked. It accomplished exactly what it was set up to do and that's helped incentivize, in a tax-efficient manner, the buildout of the midstream space within the U.S. When we look out, we have no intention of not being an MLP. We're going to stay in that format. The consolidation [wave] is going to continue a little bit more, and you can probably see the ones out there that aren't of the same scale and size that will probably be rolled up at some point.

I really think that the U.S. would not be enjoying this energy independence and security if it wouldn't have been for the midstream space and what all we've done. ■

Awaiting the Merge Surge

Midstream growth prospects limit funding at the moment, but the coming consolidation should shake things up.

MARK DRUSKOFF, Contributing Editor

You could call it a lull, but maybe intermission would be a better description. Today, midstream finds itself in a place where the action and drama of the shale revolution served as the opening act. Now, industry players wait and watch, trying to determine what will happen next.

What is clear is that upstream consolidation will have a major influence on the course of events and, to a large degree, will dictate the availability of opportunities. While the size and scale of those openings continue to take shape, midstream operators are hard at work seeking out projects where they can put capital to work. In doing so, they will have to consider a number of forces if they are to secure the financing necessary to get those projects off the ground.

Prime Mover

According to Nick Dhesi, partner, Latham & Wakins, the key is M&A.

"Upstream consolidation is the biggest mover of the market at all levels," he said.

Upstream producers are primarily being rewarded for optimizing cash flows, reducing expenditures and returning cash to investors rather than drilling more and bigger wells, Dhesi said. That dynamic will tend to tamp down the need for large-scale midstream investment.

In other cases, however, consolidation can produce positive outcomes.

"Upstream consolidation in the Permian contributes to a constructive outlook for midstream players in the basin," said Phil Segal, energy research analyst with VettaFi, the firm formerly known as Alerian. "Consolidation results in stronger customers for midstream, and in the case of Exxon's acquisition of Pioneer, the pace for production growth is set to be more aggressive than it would have been if Pioneer continued on its own."

Pinnacle Midstream II, backed by Energy Spectrum Partners, is one company that has benefitted from consolidation, according to Ben Davis, managing partner at Energy Spectrum. Pinnacle Midstream's original anchor customer was Double Eagle, which sold to Pioneer, which sold to Exxon. The Exxon acquisition was a "bullish sign" for Pinnacle because the supermajor is known for drilling, and thus increased the value of the midstream assets.

Midland Basin-focused Pinnacle announced in May it would be acquired by Phillips 66 for $550 million in cash.

Midstream buyers are not only looking to acquire an asset that is attractive on a standalone basis but one that increases utilization in its assets further downstream, said Mike Mayon, managing partner at Energy Spectrum.

"Upstream consolidation in the Permian contributes to a constructive outlook for midstream players in the basin. Consolidation results in stronger customers for midstream, and in the case of Exxon's acquisition of Pioneer, the pace for production growth is set to be more aggressive than it would have been if Pioneer continued on its own."

PHIL SEGAL, energy research analyst, VettaFi

In the deal announcement, Phillips 66 highlighted Pinnacle's Dos Picos natural gas gathering and processing system with a 220 MMcf/d gas processing plant, 80 miles of gathering pipeline and 50,000 dedicated acres. The Dos Picos could easily scale toward a second 220 MMcf/d plant, the announcement noted.

Funding Private Growth

Pinnacle Midstream is just the latest example of Energy Spectrum's approach to building midstream companies. The firm launched its first midstream-focused funds in 1996, making it one of the oldest players in the game.

Pinnacle Midstream II was "built from scratch," said Jim Benson, senior managing partner and founder of the firm. Financing Pinnacle relied heavily on equity early on, and leverage was brought in only later, he said, noting that near-term projects will need to adopt a similar capital structure.

Generally, the number of banks willing to lend into the midstream space has declined, particularly among larger national banks that provide facilities greater than $500 million, Benson said. However, smaller regional banks, such as Cadence Bank, Bank of Oklahoma and Texas Capital Bank, still serve the market by clubbing up to provide credit facilities of $100 million to $200 million, he said.

PINNACLE MIDSTREAM

Pinnacle Midstream's Dos Picos natural gas processing plant, shown during construction in early 2021, went into operation in October 2022. Pinnacle, backed by Energy Spectrum, is one midstream company that benefited from consolidation. The company's assets increased in value after its original customer, Double Eagle, was first bought by Pioneer, then Exxon Mobil. Phillips 66 reached an agreement to purchase Pinnacle for $550 million in May.

And leverage levels are not what they once were, Benson said. "Five to six times leverage is just not happening," he said, noting that project leverage needs to be kept down to the 2x to 3x level.

Energy Spectrum is redoubling its business development efforts, investing even more time and resources into getting out and talking to the market to spot greenfield opportunities, said Davis.

The quality of the rock will be a significant driver of how much risk Energy Spectrum will be willing to take, Benson said. "In the Permian, we might stretch a little bit because they are more attractive for a larger midstream or MLP [buyer]."

Although some of that decline can be attributed to interest rates, more of the blame can be placed on the fact that upstream is no longer just growing to grow.

On the public side of the markets, the equity market "remains pretty quiet," said Tim Fenn, partner at Latham & Wakins. Most of the public midstream companies have a self-funding business model that reduces the need for outside capital, he said. There have not been many tests to see if the market would even be receptive to a secondary follow-on.

Midstream companies that are considering a public offering are looking more toward mid-2025 at the earliest, Dhesi said. That timeframe is less about specific circumstances and more about being "far enough out to be talking about [an IPO]" without having to deliver on definitive plans, he explained.

"Right now, I'd say that many banks have the capital and [are interested in lending] if they see the right opportunity."

CRAIG KORNREICH, partner, Latham & Watkins

There are capital providers that would be interested in lending to the market, said Craig Kornreich, partner at Latham & Watkins. Midstream consolidation also resulted in consolidation of financing, so the number of outstanding credit commitments has been reduced. "Right now, I'd say that many banks have the capital and [are interested in lending] if they see the right opportunity," he said.

There is a paucity of big, finance-intensive projects, however, said VettaFi's Segal. Energy production growth in the U.S. has moderated, so there is less need for new large-scale energy infrastructure projects. "The smaller growth and expansion projects are mostly self-funded and many public midstream corporations and MLPs have investment-grade credit ratings

ESG TAKES A BACK SEAT

"ESG as a whole is getting less attention now than it was a year ago, when it was more of a peak topic," said Nick Dhesi, partner, Latham & Wakins. "The reality is that energy is outperforming as an investment opportunity ... and because of that, investors are focusing on performance in addition to ESG."

ESG remains a stronger focus among some pockets of capital. European institutional investors that have looked at the U.S. midstream still have "really robust, rigorous requirements around ESG," Dhesi said. It is still important to have a narrative ready to address ESG-related questions, he said.

MIDSTREAM COULD GET NEW TOOL

In recent years, asset-backed securitization (ABS) has garnered some attention in the upstream space as E&P companies have used the new mechanism to monetize producing assets by placing them in special purpose vehicles and aggressively hedging them against commodity price risk.

Now, advisers say, ABSs could also be applied to the midstream sector.

"Securitization is a financing tool that applies well when you can apply it against assets or portfolios that have predictable cash flows," said Anuj Bhartiya, senior managing director, Guggenheim Securities. Through hedging, upstream producers have been able to create predictable cash flow streams. "I think the midstream sector certainly has assets that are more infrastructure-like with long-term contracts that generally lend themselves well to securitization."

ABS "absolutely" has a role to play in the midstream, said Daniel Allison, partner at Sidley Austin. For the first deal to get done, a number of factors will need to align "just right," such as medium- and long-term contracts and investment grade—or close to investment grade—counterparties.

Upstream consolidation could actually streamline the introduction of ABS, Allison said. Following a merger, midstream companies could end up with a major or supermajor as their sole client. That would satisfy the counterparty risk question, and all that would then be needed is to tie the securitization to predictable cash flows, he said.

Some upstream ABSs already have been structured to include value for midstream gathering cash flows, said Victor Mendoza, managing director and head of oil and gas ABS at Donovan Ventures. Investors in production-backed ABSs are "getting more comfortable understanding oil and gas reserves," and so with the proper long-term contracts and creditworthy offtakers, a midstream-focused ABS is possible, he said.

PLUG POWER

A Plug Power hydrogen storage and handling facility is shown in Apple Valley, Calif. Beyond carbon capture, hydrogen infrastructure, which also sees benefits from the IRA and additional DOE incentives, holds promise for midstream.

and can raise debt if they need it. For private equity investors, energy infrastructure assets with healthy, stable cash flows are attractive."

Indeed, private capital providers are interested in the midstream space, and are looking for structured investments, Dhesi said.

But they are not looking for bank-loan-type returns, according to Kornreich. They look to provide capital higher up in the capital structure or replace unsecured debt, but the number of midstream companies requiring that type of product is not large. So, most of the interest from private capital providers is supplying the upstream operators instead of the more stable, self-funding midstream companies, he said.

Infra Money?

For "a handful of years" infrastructure funds were nearly as active in the midstream space as strategic players, but slackened as a result of ESG, said Energy Spectrum Partners' Mayon. They are not participating as actively in auction processes as they once were, he noted.

Infrastructure funds do appear to see opportunities in natural gas, and specifically in LNG, said Mayon, because natural gas is increasingly seen as a bridge fuel for the energy transition.

Characterized by huge sums of money, long timelines and a very different cast of players, LNG has the highest profile of any midstream segment because of its impact not only in U.S. domestic politics but also in global geopolitics.

Infrastructure investors have gravitated toward the LNG space because the scale of the projects means they "can put a lot of dollars to work," said Dhesi.

Given all the investment in LNG projects, it stands to reason that midstream projects serving LNG demand should also benefit. Most LNG projects are in such an early stage of development, however, that supporting projects do not yet require significant midstream investment, Dhesi noted.

Energy Spectrum's Davis said that rather than investing equity, some infrastructure investors have found success raising private credit funds to lend to the infrastructure space.

Opportunities on the Horizon

Although the growth outlook is currently muted (and thus, the need for capital is lessened), there are some green shoots that could drive an uptick in activity.

One possibility is that midstream assets could shake loose from upstream consolidation, said Latham & Watkins' Kornreich. In the upstream space, the wave of expected divestitures is generating interest among executives considering forming a management team to pursue those opportunities, he said.

The same dynamic is not yet happening in midstream, but "you definitely could see some asset packages break loose over the next year or two and new teams form and try to make their mark," Kornreich said.

The second possibility is non-core divestitures from large midstream players themselves, which have experienced their own wave of consolidation in recent years.

The universe of public midstream companies is down from more than 100 to a couple dozen larger companies, Fenn said. The result is some companies have ended up with assets "all over the place," and they need to rationalize their portfolio simply from a time and attention standpoint, he said. Invariably some of those assets will end up being considered non-core and could be divested. ■

IRA EXPECTATIONS DOWNGRADED

When the Inflation Reduction Act (IRA) debuted, there was significant interest from the midstream sector in the potential tax credits available for carbon capture and sequestration (CCS). But the enthusiasm has dimmed.

"We haven't seen much benefit on the traditional midstream side of the business yet," said Mike Mayon, managing partner at Energy Spectrum. The primary beneficiaries in midstream will be CCS projects but "those are proving tough to permit and contract," he noted.

Most companies simply can't afford to pursue such projects at a large scale because they tend to be expensive and take a lot of time to yield a return, said Nick Dhesi, partner, Latham & Wakins. For that reason, they remain in the realm of the very large players like majors or supermajors, he said.

"There's going to be a lot of waiting and seeing rather than new projects starting up," said Dhesi.

Beyond carbon capture, hydrogen infrastructure holds promise for midstream, noted Phill Segal, an energy research analyst at VettaFi. "The hydrogen industry, which is also seeing benefits from the IRA and additional DOE incentives, could also present opportunities for midstream around storing and transporting hydrogen," he said.

Opportunities Abound for Investors in Sector

Here are the metrics that financiers look for in a mature industry.

JENNY GOTTSCHALK, partner, EIV Capital | **STEVE SIMION,** vice president, EIV Capital

The shale revolution brought tremendous change to the U.S. oil and gas industry in the 2010s. Domestic hydrocarbon production grew dramatically from 5.5 MMBbl/d and 73 Bcf/d in 2010 to 12.9 MMBbl/d and 125 Bcf/d in 2023, according to the U.S. Energy Information Administration (EIA).

During that timeframe, the midstream sector required and received historic investment to expand U.S. transportation, storage and processing infrastructure to accommodate the massive growth in production. Entrepreneurial midstream companies created value by commercializing and building greenfield systems to serve new and expanding market needs.

In EIV Capital's portfolio, Bayou Midstream built and acquired assets in the western Bakken in anticipation of the growing market need for gathering and takeaway capacity. Bayou Midstream sold that system in early 2024.

Now, with the "great plumbing" largely complete, the midstream sector is shifting its priorities from large-scale greenfield capital investment to maintenance and asset enhancement capital with a focus on generating and distributing cash flow. Public midstream companies made a dramatic turn this decade from outspending cash flow to yielding free cash flow well above the broader market rate.

As the industry matures, the public midstream sector has all but stopped issuing new equity. In fact, cash has begun to meaningfully flow back to investors through distribution programs and stock buybacks.

For the foreseeable future, midstream companies and their leaders will be evaluated on their ability to deliver returns to investors, which requires strong commercial outcomes and operational excellence.

Commercial Arrangements Protect the Top Line

Midstream infrastructure is vitally important to the producers and consumers of the commodity, and the commercial arrangements must meet the needs of both. Often the greatest contributors to enterprise value are the commercial structures that deliver top-line revenue.

Historically, many midstream investments were underpinned by take-or-pay contracts, minimum volume commitments or acreage dedications. As those arrangements expire, midstream companies must implement commercial arrangements that continue to work for all stakeholders. In practical terms, it means underwriting the producing resource and expected production, ensuring rate structures have appropriate inflation escalators, and that future regulatory burdens can be recovered in the rate structure.

Through the shale era, capital was destroyed by investment underpinned by commercial agreements disconnected from the reality of the resource—today, midstream investment focuses on downside protection from the potential underdevelopment and underperformance of the underlying resource.

Operational Excellence Improves Cash Flow

Operational excellence requires company executives to continuously improve their results in three broad areas: safety, efficiency and environmental performance. EIV Capital works with its portfolio companies in these areas; examples include Canes Midstream, Woodland Midstream, and H_2O Midstream. High performance in these areas eliminates excess costs and drives meaningful improvements in cash flow.

Safety

EIV Capital expects its portfolio companies to begin every board meeting with a review of safety and environmental performance. Further, company bonus programs are expected to incorporate these metrics.

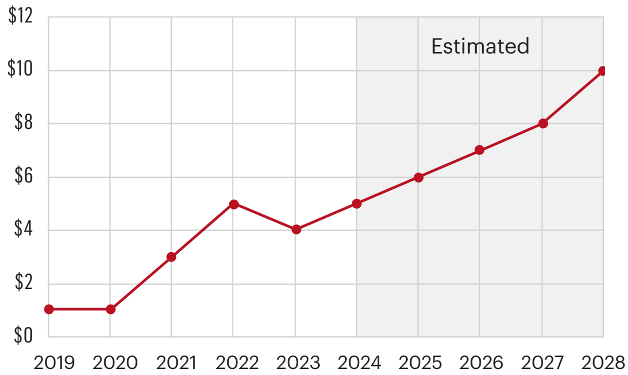
Shortly after Canes Midstream acquired a Midland Basin G&P system, they recognized that the safety culture had room for improvement. EIV supported the company's investment in implementing a top down, renewed focus on safety, which delivered measurable improvements. Canes was recognized by the GPA Midstream Association as an industry leader in safety in 2023 for having an exemplary safety record. Safety is simply non-negotiable.

Environmental

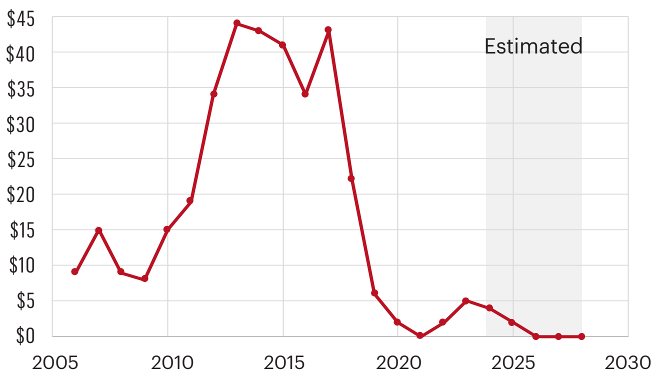
With the right team and incentives in place, the firm has seen teams deliver dramatic improvements in environmental performance. During the time that Woodland Midstream owned the James Lake gas plant, sulfur-oxide emissions declined by 75%.

Midstream operations that do not meet standards will be penalized by the methane tax, which is expected to be levied in 2025, directly tying emissions to cash flow. Attentive management, like Canes Midstream, routinely monitors methane emissions and quickly addresses issues to minimize

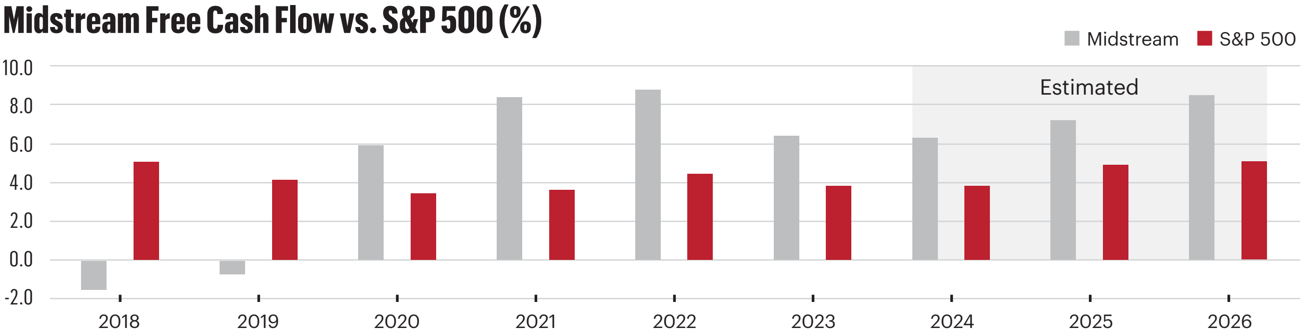
Midstream Equity Buybacks ($ billions)



Midstream Equity Issuances ($ billions)



Midstream Free Cash Flow vs. S&P 500 (%)



SOURCE: WELLS FARGO SECURITIES

gas loss and tax leakage. Canes Midstream ranks in the first quartile in Insight M's ranking and expects to avoid the methane tax as a result. Companies that deliver top-tier environmental performance can be attractive acquisition targets poised to receive outsized valuations at exit, as their performance will be accretive to the emissions profile of an acquiring company.

Efficiency

Efficiency encompasses many aspects of operations, but fundamentally it means that revenues are delivered without excess costs. Although it is obvious, one of the biggest drivers of efficiency is simply plant uptime, which is a result of robust maintenance practices and operating procedures.

By directly addressing those two areas, the Woodland Midstream team reduced unplanned downtime at James Lake to less than 1%. The improved reliable operations led to several commercial wins as operators sought the most consistent midstream provider in the area. Higher throughput and improved efficiencies drove unit operating costs at James Lake down 32% over the same period.

Once a midstream company establishes a solid foundation for its operations, management teams should shift their focus to continuous improvement and optimization initiatives. To support those efforts, all EIV Capital portfolio companies are encouraged to invest in dashboards and tools to present valuable operational data in actionable ways.

H_2O Midstream leverages real-time receipt information on its system to continually optimize the flow path of produced water to the most economic delivery points. The company also manages its cost structure by proactively curtailing its electricity demand during periods of high prices.

Opportunities to Buy and Transform

We continue to see opportunities for private equity-backed companies to acquire and optimize systems and assets which may be non-strategic to a divesting counterparty but can perform well in the hands of a focused management team.

As public companies expand and private funds mature, it is natural for segments of their portfolio to fall out of focus. In some cases, those systems may have opportunities to improve operational efficiencies or they may face capital constraints from their current ownership.

An acquiring team will often bring relationships, fresh capital and deep knowledge of the area along with experienced leadership to transform operational performance and increase commercial momentum. In cases in which sellers and acquirers have large discrepancies in valuation, private equity firms can help structure creative arrangements that bridge the gap and thus enable the transaction to close.

Energy Transition is Next Frontier for Midstream

Although the world will continue to rely on hydrocarbons for the foreseeable future, midstream companies have opportunities to be leaders in the energy transition. For example, there are numerous investment opportunities in infrastructure to handle CO_2, renewable drop-in fuels and hydrogen. Many of those projects benefit from government programs that incentivize teams who are first to market. Veteran midstream teams have the experience to deliver and operate these types of energy transition projects.

Midstream infrastructure remains critically important to deliver reliable energy and meet the demand needs of today and tomorrow. Operational excellence helps ensure safe, responsible and profitable outcomes for all stakeholders. ■

Hinds Howard: Midstream's M&A Renaissance

The conditions for dealmaking are the most favorable since the late 1990s and early 2000s.

HINDS HOWARD, Contributing Editor

Publicly traded midstream companies are having a dealmaking renaissance. Through a combination of actions taken by the companies themselves and of broader market trends, the sector finds itself in a dealmaking environment reminiscent of the sector's early days in the late 1990s and early 2000s.

I don't mean we are in an era that will see the largest deals or the most deals ever. I just mean the conditions exist for the large midstream companies to buy assets from willing sellers at reasonable valuations with limited competition.

Which Conditions Resemble Those of the Early Days?

Not many other buyers: In 2000, the midstream sector included just 14 listed companies with market cap greater than $250 million. There just were not that many companies, and even fewer that were actively pursuing M&A.

Today, there are around 20 publicly traded U.S. midstream companies and the number continues to fall. Also, like in 2000, there are not many dedicated pools of private capital actively investing in midstream assets. The massive infrastructure funds that were active in midstream M&A in 2017-2020 have been allocating elsewhere, for the most part.

Valuations: Transaction multiples on asset acquisitions in midstream in the early 2000s were around 8x-9x EBITDA. The last two years, the average asset acquisition multiples are in that same range. Even with midstream companies trading around 9x-10x EBITDA, the math works for midstream companies to buy assets at 8x-9x current EBITDA, especially if the deals are funded without equity issuance, and if the deals are "bolt-on" in nature such that they drive synergies over time.

What are the Major Differences Between the Old Days and Now?

Midstream companies today have:

- Lower payout ratios of around 50% vs. 100% plus back in the day.
- Lower leverage of around 3.5x net debt to EBITDA, down from more than 4.5x on average historically, peaking around 5.0x in 2016.
- Actual free cash flow, with many midstream companies considering buybacks and dividend increases to avoid leverage falling too far below stated targets.
- No reliance on external financing, a result of the model of retaining cash flow.
- Not as much new infrastructure needed. In the late 2010s, as competition for M&A grew more intense, many midstream companies shifted to major projects. So-called "organic growth" became the new way to grow for companies like Enterprise Products Partners, Energy Transfer and MarkWest Energy.
- No incentive distribution rights (IDR). MLPs used to have the burden of paying out extra distributions to their sponsor as their per unit distributions or number of units grew. IDRs are long gone for 95% of the midstream space (SUN and CQP the only meaningful IDR payers out there).

So, the model today is quite different. In the early days of midstream, acquisitions were generally funded by equity offerings because there was no free cash flow and limited debt capacity. Deals were still accretive because the offerings were in high demand and the multiples paid for assets were lower than the trading multiple of the companies. The more evolved model works well for bolt-on acquisitions.

How Did These Conditions Arise?

In addition to the self-help of distribution cuts, IDR eliminations and capital discipline, several factors have led to the current dealmaking environment.

The market hated the volatility of midstream, and the broken promises reflected in distribution cuts across the sector did not help. Capital moved out of the midstream sector from around 2014 to the early 2020s. More recently, midstream volatility has shifted lower and stock prices have consistently grinded higher for going on four years now.

The market hated the fossil fuel nature of their businesses. This impacted stock prices of listed midstream companies and contributed to negative fund flows for a time. But the longer lasting impact of the ESG movement was the shift away from midstream investments by large infrastructure private equity funds. That large pool of capital moves slowly, but several years ago, most private infrastructure investors came to believe investments in midstream were not worth the effort. Because even if a given midstream investment were

EnLink Midstream's Deadwood natural gas processing plant in Glassock County, Texas.

ENLINK MIDSTREAM

small in the context of a broader portfolio, there was a view that the fund managers would end up spending all their time in client reviews and in marketing meetings justifying these high carbon midstream investments. Infrastructure funds have instead targeted less "controversial" investments such as renewables, data centers and transportation.

The market has not been interested in new company formation in midstream. We have not had a midstream MLP IPO in the last seven years, not since 2017. That has left dedicated energy private equity firms without IPOs as an exit option, limiting alternatives for sellers of assets.

The market viewed midstream as a proxy for oil prices, with correlations above 0.50 from 2016 to 2022. As the sector's financial situation has improved, correlations of midstream stock prices and commodity prices have trended lower as well

In 2024, midstream stock price correlation to oil prices is around 0.24. Correlation for midstream stocks to energy stocks is down as well, from a five-year average correlation to the XLE of 0.84 to 0.73 in 2024 (through the first half of the year).

Finally, time and precedent transactions have helped seller expectations settle lower, into the dealmaking zone. In the early days of some of the above changes to the dealmaking environment, sellers were clinging to high expectations for the value of their assets upon a sale. Over time, those expectations drifted lower. Capital-constrained buyers have been disciplined over several years, which helped. The result is an ideal setup for midstream companies to continue to deploy some of their growing free cash flow into M&A at reasonable valuations, supportive of a virtuous cycle of returns.

What Could Unsettle This Current Dealmaking Equilibrium?

Nothing is permanent, and something will disrupt the recent equilibrium. I came up with a non-exhaustive list of potential disruptors:

- The anti-fossil fuel sentiment could swing back the other way and there could be too much enthusiasm for energy investment. That could manifest in the return of big private infrastructure capital into the bidding processes that raises valuations of assets or prices out midstream companies.
- Cheap money could return to the market in general, encouraging more reckless capital allocation in the midstream space. This is part of what happened to MLPs and midstream in the late 2000s through mid-2010s. Capital was cheap, midstream companies pursued growth aggressively, asset acquisition multiples shot up, returns on capital fell and the midstream business model broke down.
- Investment bankers take a shot at the IPO market. If a private midstream company successfully executes an IPO that prices at a valuation above where transaction valuations would settle, it could encourage more IPOs as the primary exit alternative. That could lead to fewer attractive assets for midstream companies to acquire, while at the same time creating new competition for future potential assets.

The current conditions rhyme with the early days of MLPs, which is a good thing, because in those early days the midstream model worked well. Growth through acquisition works … if asset valuations remain checked by capital discipline and limited fund flows.

Without the accelerant of cheap capital and other aggressive bidders, I don't see the midstream business model collapsing as it did in the mid-2010s. But like everything in the energy space, these things operate in cycles. Right now, the cycle favors the shrinking number of large, well-capitalized buyers, but that music will stop at some point. ■

'Knife Fight' for NGLs

The desire for liquids is driving M&A in the sector.

SANDY SEGRIST, Senior Editor, Gas and Midstream

Midstream players in the Permian Basin are sharpening their M&A knives to win the fight to secure NGL and add capacity, say industry experts who are watching the deals play out.

In 2023, some of the biggest names in the midstream market, Crestwood and Magellan, were bought out in M&A deals worth north of $10 billion.

In summer 2024, the midstream M&A market ball continued to roll, though it may be losing steam. Major companies are focused on developing natural gas gathering and processing (G&P) assets, and deals have generally stayed in or below the $2 billion range, with the exception of ONEOK's $5.9 billion acquisition of EnLink Midstream and Medallion Midstream.

"Gas processing is an evolving kind of space, especially with the shortage of gas capacity in the crude basins because of the growth in associated gas," said Sunil Sibal, analyst for Seaport Research Partners.

In the crowded Permian, a shrinking group of competitors continues to search for more natural gas capacity and more processing facilities for NGL—a sector of the market that's shown strong demand growth over the last two years.

In August, Enterprise Products Partners announced it would acquire Piñon Midstream, an independent with gas pipelines and processing assets in the eastern Delaware Basin in New Mexico.

It was the third Permian Basin deal this summer that included a large company buying out a smaller private with primarily natural gas gathering and processing facilities. In early May, Kinetik bought Durango Midstream in the Delaware. Energy Transfer bought WTG Midstream before the month ended.

In a June analysis, East Daley Analytics referred to Permian M&A activity as a "knife fight for the NGL barrel."

"All of these [companies] are targeting G&P [gathering and processing] for the NGL production to secure the bbl for the tariff fee on pipes, storage, fracs, LPG export and the ability to market NGLs using infrastructure," said Rob Wilson, East Daley's vice president of product.

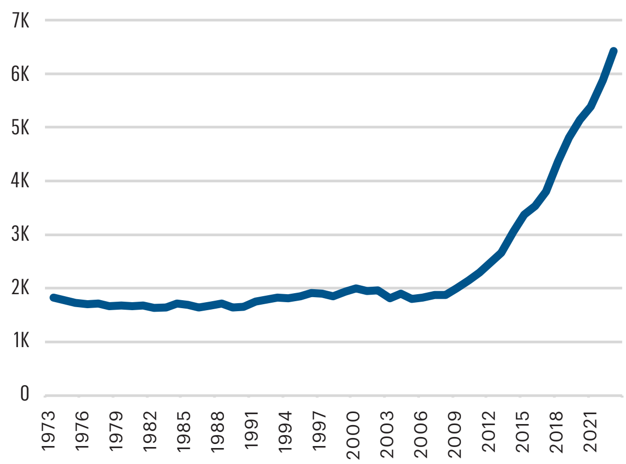
At a time when crude production remains flat and the Henry Hub natural gas price struggles to stay above $2/MMBtu, NGL have provided midstream companies a lucrative stream of income.

"Enverus has tracked $22 billion in U.S. midstream M&A year-to-date 2024, with substantially all of that focused on gas and NGLs," said Andrew Dittmar, principal analyst at Enverus Intelligence Research. "Large midstream and integrated firms want more exposure to the Permian as a growth area for their business as associated gas production volumes continue to rise and inventory life is sufficient to justify acquisition pricing."

It's currently a buyers' market for midstream companies looking to add capacity, said Hinds Howard, a portfolio

U.S. Field Production of Natural Gas Liquids

Mbbl/d



SOURCE: ENERGY INFORMATION ADMINISRTATION

Midstream M&A Focus on NGLs

Company	Acquired	Date Announced	Cost	Location
Kinetik	Durango	9-May	$1 B	Delaware Basin
Energy Transfer	WTG	28-May	$2.275 B	Midland Basin
ONEOK	Easton Energy assets	13-May	$280 MM	Near Houston
Enterprise Products Partners	Piñon Midstream	21-Aug	$950 MM	Delaware Basin

SOURCE: HART ENERGY

Kinetik midstream plant operating in the Texas Delaware Basin. Kinetik acquired Durango in early May, one of three Permian Basin deals this summer where a large public company bought out a smaller private with primarily natural gas gathering and processing facilities.

KINTETIK

manager at CBRE. After a substantial buildout in the late 2010s, larger midstream companies focused on financial discipline in the early parts of the 2020s.

"Midstream companies have done a great job in recent years of reducing debt on balance sheets, such that leverage is at or below target levels, creating optionality for excess cash flow," Howard said. "The options are to raise dividends, to buy back stock, to invest capital in growth projects or to pursue M&A."

In the Permian, G&P facilities are attractive thanks to the volume of associated gas produced in the crude-focused basin. Natural gas, thanks to low prices, only provides income to the midstream players via toll prices.

NGLs, however, provide multiple ways for large midstream companies to make money.

"Being integrated as a midstream company across the NGL value chain is very lucrative because there is a gathering fee, a processing fee, a transportation fee, a fractionation fee and an export fee for NGL volumes," Howard said. "So, getting more G&P assets upstream of an integrated system has a network effect. That's why NGLs are valuable."

The majors are also playing hardball. With fewer competitors in the area vying for fewer already-built assets, executives are moving to protect the current streams flowing on their networks.

"There is an element of defensive strategy in these M&A deals," Howard said. "You want volumes flowing on your system, so you don't want some other big midstream company to get control of NGL volumes and potentially direct them to another company. So, for an [Enterprise Products Partners] or an [Energy Transfer], it could make sense to buy a smaller company that may be shipping NGLs on your pipeline ahead of the expiration of the contracts where those volumes could go elsewhere."

Deal Review

All three of the acquired Permian Basin companies—Durango, WTG Midstream and Piñon—were in the midst of expanding their gas processing facilities in the year leading up to their mergers.

In November 2023, Durango announced it received funding to support ongoing construction at its Kings Landing Gas Processing Complex in Eddy County, N.M.

And WTG Midstream had boasted a processing capacity of 1 Bcf/d for natural gas prior to its merger with ET and continues to build two new processing plants, according to RBN Energy.

Piñon offered Enterprise a different type of processing capacity. The company had recently completed work on a sour gas processing plant and disposal wells on the eastern side of the Delaware Basin. The plant gives Enterprise a foothold in a rapidly developing area where sour gas is a known problem.

"With room for expansion on both the treating and injection side, this could spur more development in this highly prolific area, given producers will have greater access to treating and injection facilities," said James Taylor, an analyst with East Daley.

Outside of G&P producing basins, ONEOK bought assets to expand its access to NGL, prior to further processing and export. In May, the company spent $280 million in a deal to acquire 450 miles of NGL pipelines serving customers and exporters in the Houston area. The pipes had belonged to Easton Energy, a Houston-based midstream company.

The largest midstream deal of the year was an outlier. EQT spent a little over $11 billion to buy back its old midstream company Equitrans, according to Enverus. The deal was different, Dittmar said, owing to the fact that EQT made the purchase to lower its cost structure and generate more cash while the price of natural gas remains low. ■

ONEOK's EnLink/Medallion Deal is Market Wise, Financially Astute

In addition to bolstering its multibasin network, the company pulled off the $5.9 billion transaction while leaving its credit rating intact.

SANDY SEGRIST, Senior Editor, Gas and Midstream

ONEOK's latest multibillion-dollar move to strengthen its position in the Permian Basin fills in some market sector gaps, according to analysts. And executives pulled it off without damaging the company's credit quality rating.

ONEOK announced an overall $5.9 billion deal for a controlling interest in EnLink Midstream and Medallion Midstream in late August, giving the company a fully integrated basin platform that will secure traffic on its pipelines out of the country's most productive play.

"The acquisition is an entry for [ONEOK] into the Permian, which investors have been asking about for some time now," said Ajay Bakshani, director of midstream equity at East Daley Analytics.

The day before the deal was announced, East Daley published an analysis that recommended ONEOK purchase EnLink to guarantee traffic on its NGL network. ONEOK currently owns NGL egress capacity out of the basin but does not own gas processing plants in the area.

ONEOK is already in the process of doubling its NGL capacity out of the basin from 190,000 bbl/d to 380,000 bbl/d with the West Texas NGL pipeline expansion project that could be completed by year-end, according to East Daley. EnLink's Permian plants produced about 220,000 bbl/d of NGL in May.

"Although [ONEOK] owns an NGL pipeline out of the basin (West Texas NGL Pipeline), it never had a bigger presence and actively invested significant capital in America's premier basin," Bakshani said.

The strategy is not new. Most midstream merger activity over the last year resulted in large companies seeking bolt-on gathering and processing (G&P) facilities in a shrinking and competitive Permian market.

HART ENERGY

ONEOK will absorb EnLink Midstream's assets as part of the transaction, including this gas processing plant in Bridgeport, Texas, in the Barnett Shale play.

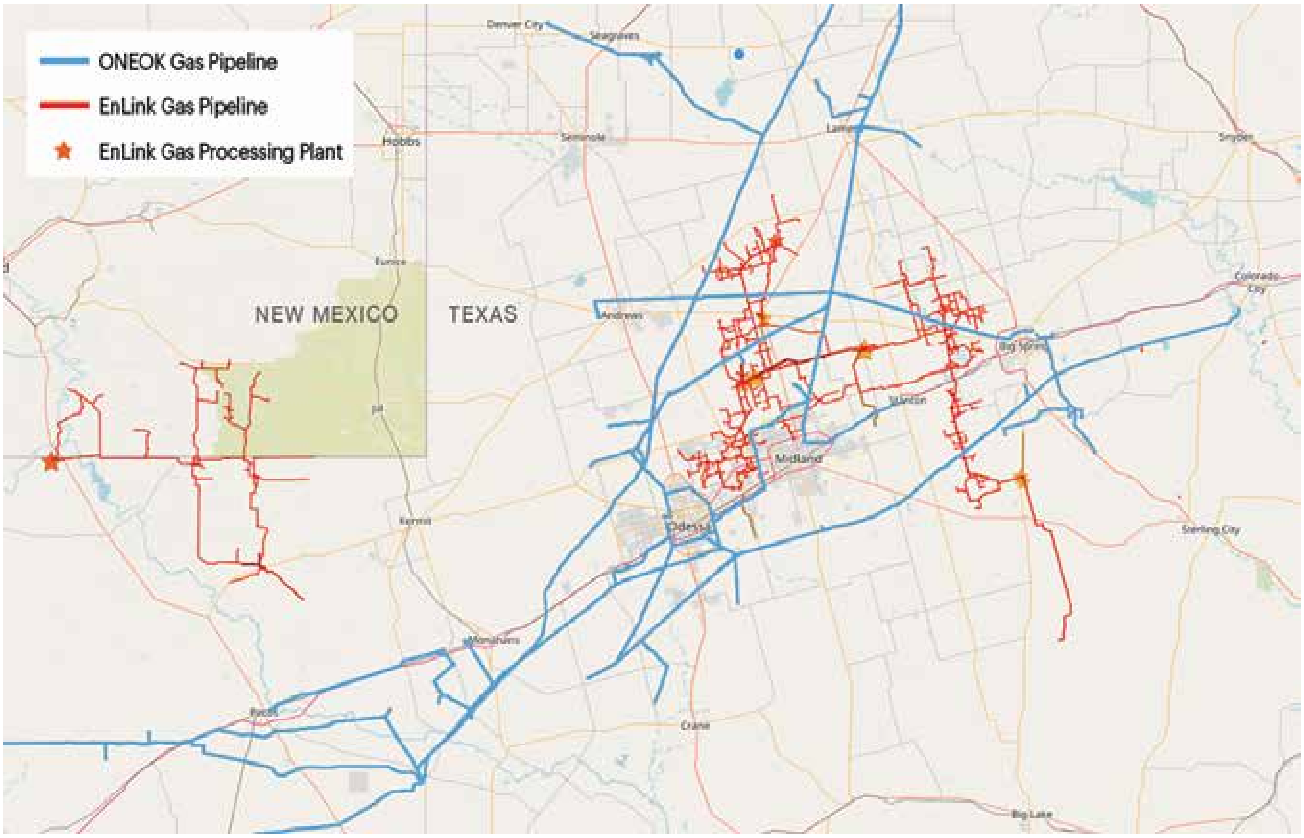
Adding Crude Capacity

ONEOK's move stands out, however, as it involves all of EnLink's assets in the south-central U.S. as well as Medallion, a crude-specific midstream company.

The Medallion acquisition shores up ONEOK's position as a crude carrier in the Permian. Medallion is the largest privately owned crude midstream company in the region, with a footprint of more than 1,300 miles of pipeline and storage facilities, primarily in the Midland Basin.

In a conference call the day after the deal was announced, ONEOK President and CEO Pierce

ONEOK/EnLink Permian Gas Connection



SOURCE: REXTAG

ONEOK will add gas processing plants as well as add to its gas pipeline network in the Permian Basin with its purchase of EnLink Midstream's assets.

Norton described the Medallion deal as "feed and fill."

"The feeding part gives us security of supply, and the fill part means that the capacity of our integrated assets would be full," Norton said.

The company's acquisition of EnLink's entire system, which includes assets in north and southeast Texas, Louisiana and Oklahoma, fits into ONEOK's network for the same reasons. The EnLink NGL network is already well connected to ONEOK.

"[EnLink's] Anadarko G&P system primarily feeds [ONEOK's] NGL pipelines already, but it is a more active system than [ONEOK's] legacy Anadarko system," Bakshani said. "[EnLink] also has a Y-grade pipe (Cajun Sibon) that connects Mont Belvieu [in Texas] to its Louisiana fractionation hub. OKE could leverage those assets and provide additional downstream connectivity, playing into."

Growing Faster

The Easton Energy acquisition, one of several deals over the last year, has made ONEOK into one of the fastest-growing midstream companies in the U.S.

In May 2023, ONEOK made an $18.8 billion deal to acquire Magellan Midstream Partners, one of the largest companies in the U.S. sector. Twelve months later, the company bought Easton's NGL pipeline network in Southeast Texas for $280 million. In July, the company announced it was expanding a refined products pipeline to the greater Denver area in a $480 million project.

Financially, the deal had no impact on ONEOK's credit rating from capital market company Fitch Ratings.

"Scale matters in the midstream sector, and OKE will be adding roughly $1 billion in annual EBITDA (based on OKE owning 43% of EnLink) to its existing roughly $6 billion in base EBITDA, based on Fitch's calculation and existing assumptions," the company wrote in an analysis of the deal. "Should OKE acquire 100% of EnLink, the EBITDA contribution could be closer to $1.75 billion."

In announcing the deal, ONEOK executives said the company is planning to pursue the remainder of EnLink's common units through a tax-free exchange for ONEOK's shares.

The transaction will increase ONEOK's leverage as the company takes on incremental debt and assumes EnLink's unsecured debt. Fitch expects ONEOK's leverage to increase to close to 4.0x, below Fitch's negative leverage sensitivity of 4.7x.

"Fitch considers the diversification benefits, as well as increased scale and potential synergistic opportunities, to be offset by higher expected leverage," the analysis said. "All of this leads to Fitch's estimation that this transaction is neutral for OKE's credit profile." ■

New EPA Regs Could Hinder Gas Plant Construction

The rules are designed to accelerate the retirement of coal plants, but they raise costs for new natural gas facilities.

ARBO, contributed analysis

In April, the Environmental Protection Agency (EPA) finalized four significant regulations aimed at coal and natural gas-fired power plants (Power Plant Rules). The rules address air emissions, including greenhouse gasses (GHGs) and air toxics, wastewater discharge and ash disposal from coal-fired power plants. Rules specifically targeting power generation affect the generation mix.

Stakeholders need to understand how new rulemaking will impact sector costs, potentially resulting in supply and demand changes.

A clear goal of these rules is to accelerate coal plant retirements by increasing compliance costs. While existing natural gas plants are not affected, the rules do regulate new natural gas plants and modifications, raising compliance costs for these facilities as well.

Understanding the Repercussions

The EPA's new regulations for power plants have significant implications for both coal and natural gas-fired plants.

While the rules impose stringent standards on coal plants, they also set new benchmarks for new natural gas plants and future modifications to existing natural gas plants, particularly in regard to GHG emissions. The added compliance costs will make it challenging for the natural gas industry to respond to increasing power demand and replace demand created by coal-powered plant retirements—more of which are likely because of the rules.

The GHG Power Plant Rule: Three Categories & Carbon Capture for New Baseload

GENERATION

Of the four power plant rules, the one that most impacts natural gas plants establishes new source performance standards and GHG emission guidelines from new, modified and reconstructed fossil fuel-fired power plants, including natural gas-fired combustion turbines. To understand how the rule applies to natural gas plants, it is important to understand the key technology types for natural gas generation as well as some industry-specific terminology.

The four technology types employed for natural gas generation include:

- Combined-cycle gas turbines (CCGT);
- Simple-cycle gas turbines (SCGT);
- Steam turbines (ST); and
- Internal combustion engines (ICE).

Generally, CCGT plants are highly efficient, allowing them to generate low-cost power over extended periods, which makes them ideal for serving base and intermediate loads. In contrast, SCGT, ST, and ICE plants are used primarily to meet peak demand on the electric grid and therefore, run less frequently. These three types can start and ramp up to full power quickly, which is critical in markets with an increasing concentration of intermittent renewable generation.

A power plant's "capacity factor" indicates its operational intensity, expressed as a percentage of the power it generates relative to its maximum "nameplate" capacity. A plant with a capacity factor of 100%, for example, would be operating continuously. But power plants have capacity factors that are lower than their nameplate capacities because they shut down occasionally for reasons like maintenance, when the energy source used is intermittently available (as in wind and solar) or because the plants only run during times of peak demand.

The rule separates potential new or reconstructed combustion turbines (regardless of fuel type) into three subcategories based on annual capacity factor, focusing on the amount of potential electric output sold—low, intermediate and base load. The rule also assigns CO_2 emissions standards by applying the "best system of emission reduction" (BSER) within these subcategories to determine how much reduction is possible. The BSER is an EPA standard that identifies the most effective and feasible means of reducing emissions based on factors like technological feasibility, cost, environmental impact and energy requirements. It is important to note that sources subject to a BSER can meet a reduction limit without using the specific technologies identified in the standard by employing alternative methods that achieve the same or greater level of emissions reduction.

The rule has three categories of generators, each with its own BSER and CO_2 emission standards.

New regulations aimed at coal and natural gas-fired power plants could price out not just coal plants, but also affect new construction of natural gas plants.

SHUTTERSTOCK

CATEGORY 1: LOW-LOAD PEAKING GENERATION: LESS THAN 20% CAPACITY FACTOR

The low-load subcategory is made up primarily of peaking generators, which have a low capacity factor (selling less than 20% of their potential electric output) because they generally only turn on in times of peak demand. The BSER for low-load generators is simply the use of lower-emitting fuels like natural gas. The CO_2 emissions standard is between 120 to 160 lb CO_2 /MMBtu, depending on the fuel source.

CATEGORY 2: INTERMEDIATE LOAD: BETWEEN 20% AND 40% CAPACITY FACTOR

For intermediate-load generators that sell between 20% and 40% of their potential electric output, the BSER uses highly efficient simple cycle technology in combination with the best operating and maintenance practices. The CO_2 emissions standard is different from the low-load subcategory in that it is based on megawatt hours (MWH) instead of MMBtu—1,170 lb CO_2 per MWH. This makes sense because the BSER is focused on technology as opposed to fuel.

CATEGORY 3: BASELOAD: MORE THAN 40% CAPACITY FACTOR

For new or modified baseload generators that sell more than 40% of their potential electric output, the BSER has two phases. The first is similar to the intermediate load category but focuses on highly efficient combined-cycle technology (as opposed to simple-cycle) and best operating and maintenance practices. The second and most controversial phase requires 90% carbon capture and storage (CCS) by 2032.

Practical Implications for Natural Gas Facilities

Notably, the final rule does not directly address existing natural gas combustion turbines.

Instead, the EPA has initiated a separate rulemaking process to regulate CO_2 emissions from existing natural gas electrical generating units (EGUs). This forward-looking approach is significant for two reasons. First, roughly 42% of power generation currently provided by natural gas facilities will not be affected by this rule. Second, litigation could change everything, and litigation is likely.

In West Virginia v. EPA, decided in 2022, the Supreme Court ruled 6-3 that the EPA lacked the statutory authority to implement the 2015 Clean Power Plan (CPP), which identified the BSER for power plants as "generation-shifting" electricity production from coal to natural gas and renewables. Under the CPP, operators could comply by reducing coal-fired production, investing in renewable energy or buying emission credits in a cap-and-trade system. The court applied the "major questions doctrine" and held that Congress did not

Construction of a modern combined-cycle gas turbine power plant. New construction of gas-fired power plants will be beholden to the new EPA regulations.

SHUTTERSTOCK

provide "clear congressional authorization" for the EPA to use generation-shifting as the BSER.

The baseload BSER CCS requirement in the new rules is similar to the rejected generation-shifting plan in that both require significant economic investment to comply and are politically sensitive, two factors the Court cited under its application of the major questions doctrine. Litigation is likely to challenge this on similar grounds.

The Scope of Impact

Just how many future power plants could be impacted by this rule?

The rule applies to projects that begin construction or reconstruction after May 23, 2023. To understand the implications, planned and retrospective capacity data from the Energy Information Administration (EIA) was analyzed for additional context. EIA data for planned natural gas power generation data includes only nameplate capacity. Capacity factor data is retrospective. Although it is impossible to predict the exact capacity factor for planned generation, looking back at historic capacity factors by technology type provides useful insights.

The first step was to examine the EIA's most recent year of finalized generation data from 2022 and note the weighted average capacity factor of each natural gas generation technology. Next, the cumulative nameplate capacity of currently planned generation was obtained from the most recent EIA-860M filing. By comparing the two and assuming that generators of a given technology will be used as it has been in recent years, it was possible to make useful inferences. For example, the average capacity factor of combined cycle generators has been around 56%.

It is worth noting that capacity factors have gotten more efficient over time. The newest CCGT plants (2014-2023) had the highest average capacity factor in 2022 at 66%. Plants from 1999-2013 averaged 57%, while those from the 1980s to 1998 had the lowest at 36%. To be conservative, the total average capacity factor of 56% was applied to current planned capacity.

Of the 160 generators currently planned, 36 are CCGT, with a combined nameplate capacity of 11,092 MW. If these average at least a 56% capacity factor, many would be regulated under the baseload category (at least 40% capacity factor), subject to the 90% CCS requirement by 2032.

Three Coal Rules and What Comes Next

The remaining three power plant rules focus on coal-fired power plants:

1. Updating the Mercury and Air Toxics Standards to tighten emissions limits for toxic metal;
2. Reducing pollutants discharged through wastewater; and
3. Taking actions to protect communities from coal ash contamination.

If the rule withstands litigation, these requirements collectively are likely to force the closure of more coal plants because of the increasing cost of compliance.

More coal retirements translates to more opportunities for other sources to replace baseload generation, but if the new natural gas rules withstand litigation, compliance costs may result in new natural gas generation being priced out, unless significant advances are made in CCS by 2032 that make it competitive.

As with any new rulemaking, the consequences are uncertain. The presidential election could impact the changes, as could the results of litigation. The extent of real-world impacts will only be known once the dust settles. ■

Counting on CCS

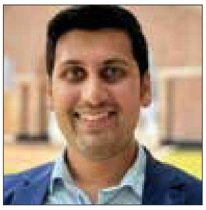
Is carbon capture and sequestration about to turn the corner? Some obstacles may stand in the way.

VELDA ADDISON, Senior Editor, Energy Transition

Capturing and burying troublesome greenhouse gas deep underground is considered to be a solution for lowering emissions. But carbon capture and sequestration (CCS) must overcome some obstacles, experts say, as companies push to commercially scale technologies to bring down costs and U.S. regulators entice developers with tax incentives.

One impediment at this stage for CCS in the U.S. is the combination of regulatory hurdles, particularly for Class VI well injection, and development hurdles, such as navigating front-end engineering development, according to Rohan Dighe, analyst for Wood Mackenzie.

"Companies are really having to decide if they're going to move forward with projects, how they're going to execute them, when they're going to execute them," Dighe told *Midstream Business*. "We've seen a lot of companies move from early development to advanced development. But now what we're seeing is companies are actually having to put money forward and move forward with FID.... We're moving past the announcement phase more into an execution phase."



"We're moving past the announcement phase more into an execution phase."

ROHAN DIGHE, analyst, Wood Mackenzie

Time will tell how many projects progress.

CCS is unfolding at varied rates in the U.S. and abroad amid global ambitions to cap global warming to about 1.5 C. The suite of technologies is seen as essential to helping hit the target. While progress is evident on some fronts, more action may be needed when it comes to infrastructure and economics to make projects a reality.

Currently, there is about 25.7 mtpa of capture capacity in

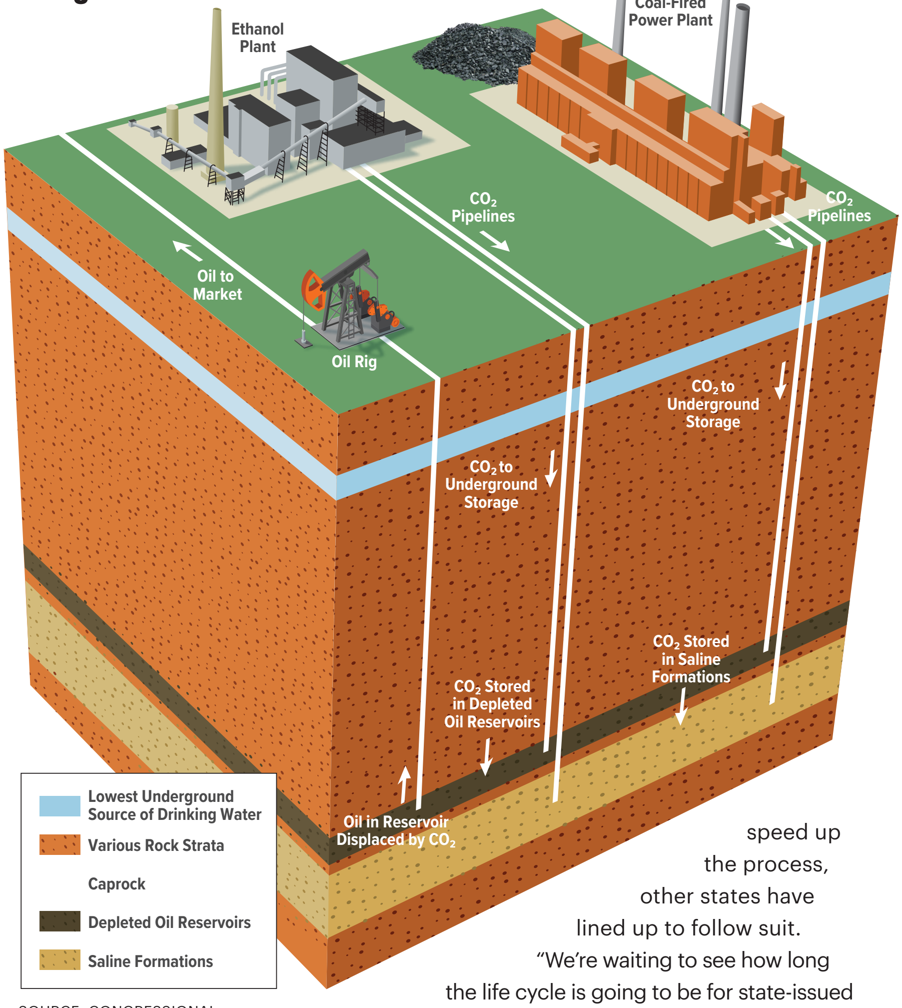
CCS Facilities Currently Operating in the United States

Name of Facility	Date CCS Operations Began	Location	Type of Production	CO_2 Used for Enhanced Oil Recovery?	CO_2 Capture Capacity (Millions of metric tons per year)
Terrell	1972	Texas	Natural Gas Processing	Yes	0.5
Enid Fertiziler	1982	Oklahoma	Ammonia (Fertilizer)	Yes	0.2
Shute Creek	1986	Wyoming	Natural Gas Processing	Yes	7.0
Great Plains	2000	North Dakota	Hydrogen and Ammonia (Fertilizer)[A]	Yes	3.0
Core Energy	2003	Michigan	Natural Gas Processing	Yes	0.4
Arkalon	2009	Kansas	Ethanol	Yes	0.5
Century Plant	2010	Texas	Natural Gas Processing	Yes	5.0
Bonanza BioEnergy	2012	Kansas	Ethanol	Yes	0.1
Air Products	2013	Texas	Hydrogen	Yes	0.9
Coffeyville	2013	Kansas	Hydrogen and Ammonia (Fertilizer)[A]	Yes	0.9
Lost Cabin	2013	Wyoming	Natural Gas Processing	Yes	0.9
PCS Nitrogen	2013	Louisiana	Ammonia (Fertilizer)	Yes	0.3
Petra Nova	2017[B]	Texas	Electric Power	Yes	1.4
Illinois Industrial	2017	Illinois	Ethanol	No	1.0
Red Trail Energy	2022	North Dakota	Ethanol	No	0.2

DATA SOURCE: CONGRESSIONAL BUDGET OFFICE, USING DATA FROM THE GLOBAL CCS INSTITUTE. SEE WWW.CBO.GOV/PUBLICATION/59345#DATA.
CCS = CARBON CAPTURE AND STORAGE; CO_2 = CARBON DIOXIDE.
A. GASIFICATION OF COAL- OR PETROLEUM-BASED COKE RESULTS IN A MIXTURE OF HYDROGEN AND OTHER ELEMENTS, WHICH CAN BE USED TO PRODUCE AMMONIA.
B. THE PETRA NOVA CCS FACILITY SHUT DOWN IN 2020 AND REOPENED IN 2023.

the U.S. compared to about 56 mtpa globally, according to Wood Mackenzie. Ten years from now, the consultancy estimates there will be 125 mtpa of capture capacity in the in the U.S. and 448 mtpa globally.

How Carbon Capture and Storage Works



SOURCE: CONGRESSIONAL BUDGET OFFICE

Incentivizing Action

Getting to that goal will require large investments: about $196 billion in total. About half of the investment needed is associated with carbon capture, with $53 billion for transport and $43 billion for storage. Most of the investment is expected to come from Europe and the U.S., where the 45Q tax credit is incentivizing CCS projects and bolstering the business case.

The U.S. 45Q tax credit offers $17/mt for sequestered, qualified CO_2. However, the value jumps to $60 per ton for storage associated with enhanced oil recovery (EOR); $85 per ton for dedicated geologic storage; $130 per ton for direct air capture with carbon utilization; and up to $180 per ton for direct air capture with carbon storage.

But that likely will not be enough when it comes to deploying CCS for industrial applications such as steel production, cement production and petrochemical refining.

"The 45Q credit is not sufficient alone to justify deployment of CCS," Dighe said. "So, these companies need to find other ways to monetize the CO_2 captured. That could be in the form of premiums for things like steel, if they're able to sell decarbonized steel at a higher price or if they're willing to sell those credits. Or, if the company has internal carbon abatement targets they've set for themselves, there might be value there."

At this point, without a clear idea of how much premiums could be, some companies do not have the economic incentive to move projects forward, he said.

On regulations, Louisiana, North Dakota and Wyoming have gained primacy over wells built to sequester CO_2, putting the states in charge of permitting and enforcement responsibility instead of the federal government. Hoping to speed up the process, other states have lined up to follow suit.

"We're waiting to see how long the life cycle is going to be for state-issued Class VI well permits," Dighe said. "We're not entirely sure, but it's certainly going to be shorter than the EPA issued Class VI well permits, which take a particularly long amount of time."

"You're definitely starting to see an uptick in the development."

COLLEEN JARROTT, partner, Hinshaw & Culbertson

Leading on the Gulf

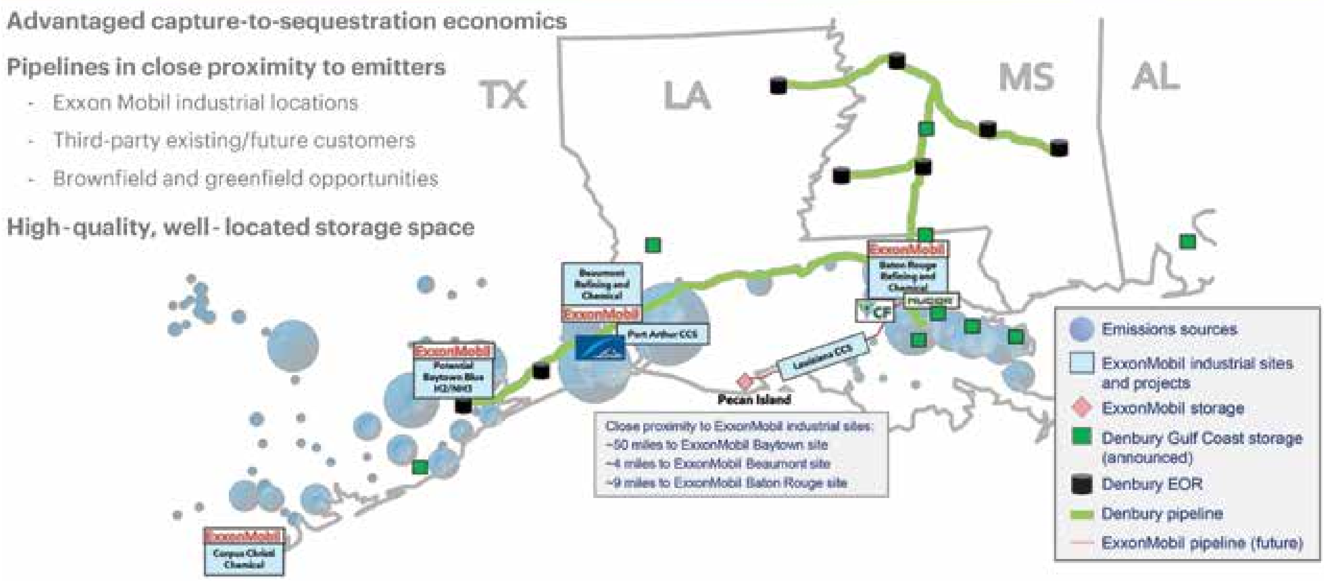
In Louisiana, the first state to receive primacy, legislators have been taking bold steps to strengthen CCS.

"You're definitely starting to see an uptick in the development," said Colleen Jarrott, a Louisiana-based energy attorney and partner with Hinshaw & Culbertson. "In Louisiana, we have about 55 projects that are pending."

Many of the projects sprung up following the passage of the Inflation Reduction Act, she said, but Louisiana regulators have enacted rules to enhance these projects. Six made it through bipartisan politics and got the governor's signature. The new laws, which took effect Aug. 1, include one that gives pipeline companies authority to expropriate property rights for pipelines transporting CO_2 for CCS projects and another that authorizes unitization for CO_2 sequestration.

"If one landowner is holding out, that won't totally sink the entire project. As long as you're able to show that you have 75% agreement of the other landowners, you're able to use a unitization process and go to the commissioner of conservation

Combination creates strong U.S. Gulf Coast position



SOURCE: EXXON MOBIL

and get a certificate of unitization," Jarrott said. "You will be able to then use that for pore space."

Jarrott does not see anything on the legislative side in Louisiana that would hinder the state's ability to scale up CCS, though some issues could arise before the next session rolls around. Like others, she pointed out that the projects are still expensive—which may limit the participation of smaller companies.

Then, there's the matter of infrastructure.

Dominating Infrastructure

The Gulf Coast has dominated CCS activity in the U.S. because of its abundance of existing CO_2 pipelines and infrastructure. Other areas are not as fortunate. Massive amounts of infrastructure will be needed to move CO_2 from capture locations to sequestration sites.

Citing studies conducted by the Great Plains Institute and U.S. Department of Energy (DOE), the Global CCS Institute said the "current CO_2 pipeline transportation network in the U.S. must increase by four to 18 times its current size by 2050 to reach our climate goals."

Current incentives are insufficient for some pipeline companies to let new projects proceed, Dighe said. It may make more sense from a capex perspective to convert existing pipelines, he said, though he cautioned that involves considerable work.

"Transport capacity is a risk because people don't want to build a pipeline if there's no capture, but then no one's going to build transport," he said. "Capture becomes expensive and then it becomes a cycle of people not doing stuff. So, it's like everyone's trying to see who blinks first."

Companies with money, technical know-how and access to infrastructure, however, are strategically moving forward.

The Hub Approach

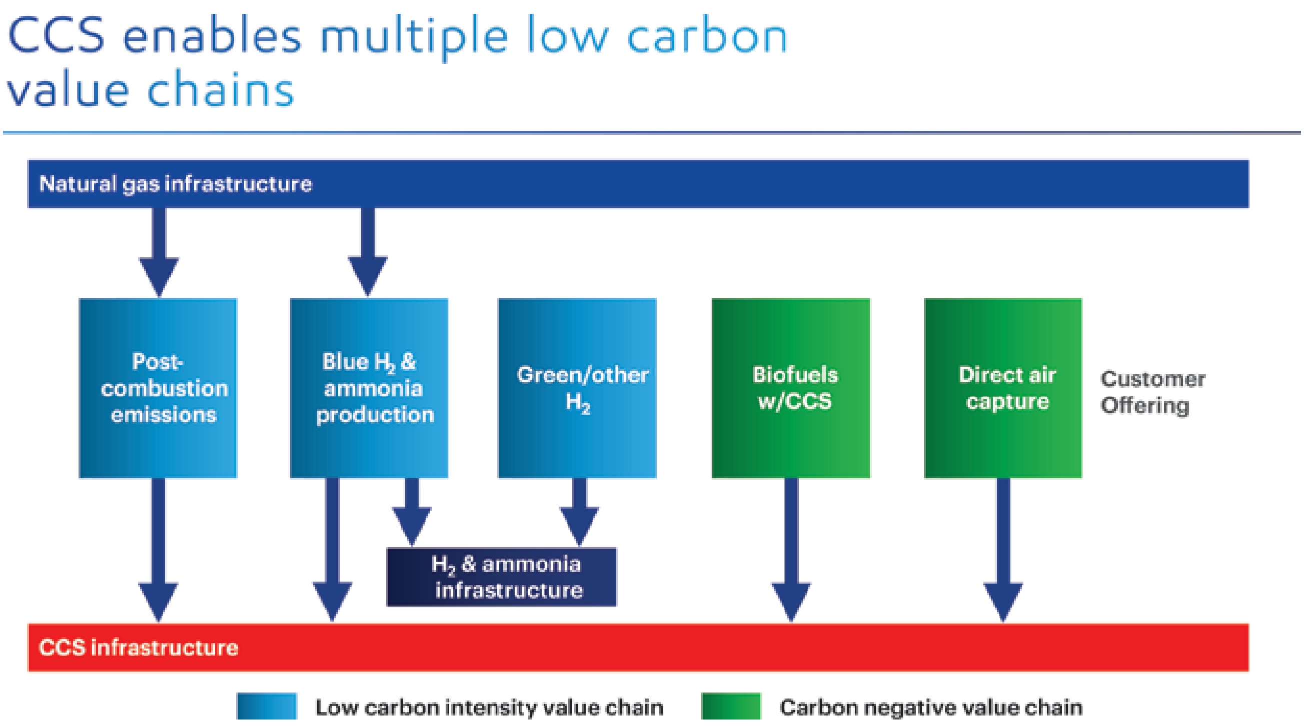
Texas-based Exxon Mobil is among the companies advancing ambitious plans to build out a CCS network. The company became the owner of the nation's largest carbon pipeline network in 2023 when it acquired Denbury in a transaction valued at $4.9 billion. The deal added more than 1,300 miles of pipeline mostly in Louisiana, Texas and Mississippi and 10 onshore sequestrations sites, helping to pave the path toward a potential estimated 100 mtpa of CO_2 emissions reduction.

Now, with access to more than 15 onshore storage sites and more than 1,700 miles of CO_2 pipeline plus natural gas infrastructure, CCS customers on contract, and access to large industrial emitters along the U.S. Gulf Coast, Exxon Mobil is driving CCS growth.

In Baytown, Texas, Exxon is developing a low-carbon intensity hydrogen plant, using natural gas as feedstock alongside carbon capture. The company plans to produce up to 1 Bcf/d of hydrogen while capturing more than 98% of the CO_2 for storage underground. The CCS piece of the project would be among the world's largest, storing up to 10 million metric tons (mt) of CO_2 per year—equal to the emissions from more than 2 million cars.

This CCS project is part of the Houston carbon capture hub that has brought together roughly a dozen companies to reduce industrial CO_2 emissions. Exxon has lined up definitive agreements with customers from three industries: Linde, industrial gases; CF Industries, fertilizer manufacturing; and Nucor Corp., steel.

"These are actual projects in motion. The definitive agreements, the civil works, are either done or progressing



SOURCE: EXXON MOBIL

well," Carl Fortin, global business manager of carbon capture and storage for the supermajor, said during an energy conference in Houston. "The first one of these projects will roll out next year. So, CCS is alive and happening. … It's not all just talk."

One-Stop Shop

Putting its CANSOLV CO_2 technology to work capturing CO_2 post-combustion, Shell is betting big on CCS. In addition to licensing its technology, the company has three operating CCS sites and about a dozen CCS projects in development globally, according to the company's website.

However, "fast forwarding to this year. You can see that our pipeline of projects, our active projects have doubled. We've doubled our reference list," Alexis Griffin, decarbonization technology licensing director for Shell, said during the energy conference. She referred to projects in play implementing Shell's CANSOLV technology.

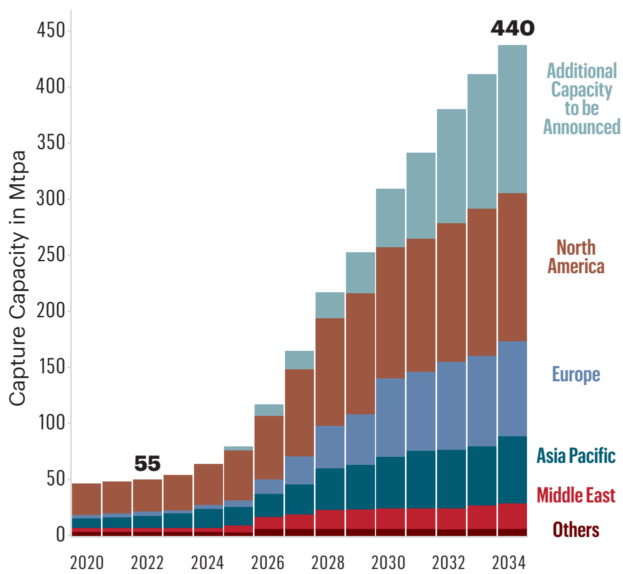
Shell teamed up with TechnipEnergies to serve as a one-stop shop to deliver CCS projects from concept to completion, said Venki Desai, commercial director for Technip. Shell provides the technology, and Technip serves as the EPC provider.

"What we have is a commercially proven, robust technology. We have high loading efficiencies, even at lower concentrations at 3-4% in flue gas. We can achieve up to 95% capture. And as you go higher into 8-10% concentration, then we can go all the way up to 99%," Desai said. "So, from our experience on having operated these units over several years now and also working closely with our experts and Shell's experts, we have been able to improve the technology in terms of emissions, lower degradation rates and lower energy consumption when compared to what it was 10 years ago."

In June, Shell took final investment decisions (FID) on the Polaris carbon capture project at its Scotford refinery and chemicals complex in Alberta, Canada, and the Atlas Carbon Storage Hub with partner ATCO EnPower. Both projects are expected to start operations near the end of 2028.

Hopes are to see FID for the Calpine CCS project in Baytown by first-quarter 2025. The project, which was in

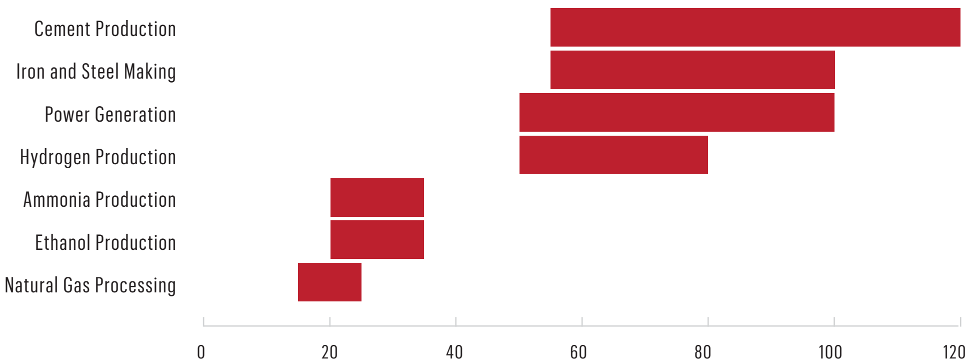
Capture Capacity Build-out to 2034, by Region



SOURCE: WOOD MACKENZIE, LENS CARBON DISCOVERY

Estimated Range of Costs for Capturing a Metric Ton of CO_2, in the United States in 2019, by Source

2019 Dollars



Estimates of the cost to capture a ton of CO_2 vary by industry and by such factors as the amount of exhaust gas from a plant, the concentration of CO_2 in that exhaust, and its pressure.

DATA SOURCE: CONGRESSIONAL BUDGET OFFICE, USING DATA FROM INTERNATIONAL ENERGY ADMINISTRATION, ENERGY TECHNOLOGY PERSPECTIVES 2020-SPECIAL REPORT ON CARBON CAPTURE, UTILIZATION, AND STORAGE: CCUS IN CLEAN ENERGY TRANSITIONS (SEPTEMBER 2020), P. 101, HTTPS://TINYURL.COM/2WB55RZM. SEE WWW.CBO.GOV/PUBLICATION/59345#DATA.

ESTIMATES OF CAPTURE COSTS INCLUDE THE COST TO COMPRESS CAPTURED CO, FOR TRANSPORT.

the FEED phase in June, is designed to capture 95% of the CO_2 emitted from Calpine Energy's 830-MW gas-fired power station, using Shell's CANSOLV solvent to capture more than 2.2 million metric tons (MMmt) of CO_2 annually. The captured CO_2 will be transported and sequestered in a saline storage site on the Gulf Coast.

The project would be the first full-scale implementation of CCS technology at a natural gas combined cycle power plant in the U.S., according to the DOE, which awarded the project funding.

Eyeing Economics

As companies move into FEED with government support, Dighe said some are going through different engineering providers to better understand costs, how various technologies compare and how costs can be lowered from a capture perspective.

"CCS technology in general is at this kind of point in its life cycle where it's both relatively well understood, but also there's these new technologies for carbon capture that that are not as well understood," he said. "We don't really know what they're going to cost. We don't know how they're going to be executed at scale. They promise to reduce a lot of the costs of legacy CCS technologies."

Estimates from the International Energy Agency show CO_2 capture is roughly \$15-\$35/mt (in 2019 dollars) in natural gas processing and ammonia and ethanol production, according to a 2023 Congressional Budget Office (CBO) report on CCS. Capture costs are about \$50-\$120/mt in power generation and other industrial processes such as the production of cement, iron, steel, or hydrogen.

Factors affecting costs include the concentration or purity of CO_2 captured, but storage is also a concern.

"It hasn't really been done at scale yet," Dighe said.

"The revenue side is more complicated because it's a market problem.... The market needs to be willing to pay for decarbonized goods in order to... overcome the cost difference between 45Q and the actual capture costs."

According to Dighe, global markets with consumers willing to pay premiums for green cement or green steel do not exist, so reliance today is on government mandates.

"To alleviate some of those issues, some companies are trying really hard to focus on getting offtake agreements in places like Europe where you have regulatory environments that require decarbonized goods," Dighe said.

Utilization has a role to play, as well.

Main Ingredient

Today, CO_2 is mainly used in fertilizer production and EOR, but tech companies have expanded the possibilities.

U.S. Steel signed an agreement this year to capture and mineralize up to 50,000 metric tons of CO_2 annually using CarbonFree's SkyCycle technology. CarbonFree's technology converts CO_2 into a version of calcium carbonate that can be used to make paper, plastics, personal care products, paint and building products.

Biotechnology companies are using CO_2 to make fertilizer, fuel, food proteins and other applications. It could also be used to produce e-fuels when combined with hydrogen.

"That is a really expensive technology because you need green hydrogen along with it. And so, that becomes less likely to alleviate these concerns about high cost of capture right now in the near term," Dighe said.

There are about 15 CCS sites operating in the U.S., according to the CBO report. Combined, the facilities have the capacity to capture 0.4% of total annual CO_2 emissions. That percentage could increase to 3% if the more than 120 facilities are under construction or in development are completed.

"Those percentages are small, in part, because CCS is generally used in sectors that have the lowest costs for capturing CO_2—such as natural gas processing and ammonia and ethanol production—and those sectors account for a small share of total U.S. CO_2 emissions," the report states. "Almost all CCS facilities recoup some of their costs by using the captured CO_2 to force more oil out of partially depleted oil wells." ■

Texas Gas Vital to Mexico's Nearshoring Boom

Continued U.S. piped-gas exports to Mexico bode well for Eagle Ford and Permian producers.

PIETRO D. PITTS, International Managing Editor

Laydown of the 9-km Altamira section of TC Energy's Sur de Texas-Tuxpan pipeline. The pipeline follows an underwater route in the Gulf of Mexico that stretches from a border point near Brownsville, Texas, to Tuxpan in Veracruz, Mexico.

ALLSEAS

Texas, home to the Eagle Ford Shale and Permian Basin, accounts for 91% of U.S. piped-gas exports to Mexico. This, as the piped-gas trade with Mexico has increased 554% over the last 21 years, peaking at 6.1 Bcf/d in 2023.

Mexico's demand for U.S. piped gas will continue to rise to meet growing demand from its electric and industrial sectors to come from nearshoring, followed by massive demand that will emerge from its nascent LNG exporting sector. The latter, in particular, provides Permian producers with a crucial outlet for rising production. But as analysts tell *Midstream Business*, headwinds related to moving gas molecules persist on both sides of the border.

Mexico's rising demand for U.S. piped gas has been driven by two key factors, according to Mexico's Energy Secretariat (Sener). The first is financial strain at Petróleos Mexicanos (Pemex), including payment obligations to the federal government, which limit the state-owned company's ability to increase gas production. The second is the availability of cheap U.S. shale gas.

Unlike Argentina and Venezuela, Mexico is neither sitting on the largest technically recoverable shale resources in the Americas nor the world's largest oil reserves. Mexico is simply a manufacturing powerhouse.

Although rising electric and industrial sector energy demand has been increasingly met by growth in piped gas from the U.S., Mexico will need to manage its energy supply or risk growth impacts to its nearshoring boom, already happening, and a looming LNG export boom.

Mexico attracted inward foreign direct investment (FDI) flows of around $36 billion in 2023, the highest level in 18 years, according to data published by BMI, a Fitch Solutions company. This compares to around $14 billion in 2006.

"The inability to supply affordable and reliable energy (electricity and natural gas) risks Mexico's prospects to fully grasp the nearshoring opportunity. Amid the trade war between the U.S. and China, especially in the realm of electric vehicles, Mexico must up its game to attract investments from firms like Tesla [Motors], which seeks to be competitive vis-à-vis its

Four Major Texas-Mexico Pipelines

SOURCE: REXTAG

FOUR PIPELINES MOVE TEXAS GAS TO MEXICO

Brownsville, Presidio, Rio Grande and San Elizario and their associated pipelines have the capacity to transport 7.3 Bcf/d to the U.S.-Mexico border, where they connect with pipelines in Mexico. The pipelines include the Sur de Texas-Tuxpan, Trans-Pecos, Comanche Trail and Agua Dulce.

Sur de Texas-Tuxpan

The 497-mile Sur de Texas-Tuxpan pipeline has the capacity to transport 2.6 Bcf/d. The pipeline follows an underwater route in the Gulf of Mexico that stretches from a border point near Brownsville, Texas, to Tuxpan in Veracruz, Mexico. In Mexico, the pipeline supplies gas to electricity generation plants in Tamaulipas and Veracruz. In addition to a connection with Mexico's National Center for Natural Gas Control (Cenagas by its Spanish acronym), the pipeline has interconnections with TC Energy's Tamazunchale and Tuxpan–Tula pipelines as well as other transporters in the region. Through this route, Permian gas reaches power plants in Mexico City, the capital and largest city in the country, as well as markets in Merida and the Yucatan Peninsula.

Trans-Pecos Pipeline

The 148-mile Trans-Pecos pipeline has capacity to transport 1.4 Bcf/d. It originates at the Waha Hub near Fort Stockton, Texas, in northern Pecos County and terminates at the U.S.- Mexico border near Presidio, Texas. The pipeline is part of the Wahalajara system, which connects Waha with Guadalajara, Mexico's second-most populous city. It also serves other population centers in West-Central Mexico.

Comanche Trail

The 181-mile Comanche Trail pipeline has capacity to transport 1.1 Bcf/d. The pipeline connects Waha with San Elizaro, Texas. From there it delivers gas to Chihuahua, Mexico, through the 15-mile San Isidro-Samalayuca transportation system.

Agua Dulce

The 120-mile Agua Dulce pipeline has capacity to transport up to 2.2 Bcf/d from the Agua Dulce Hub in Nueces County, Texas, to a point near Rio Grande City, Texas. The pipeline transports Eagle Ford gas to Mexico via the massive Gasoducto Los Ramones pipeline, which passes through the Mexican states of Tamaulipas, Nuevo León, San Luis Potosí, Querétaro and Guanajuato.

"To date, price signals and demand growth in [Mexico's] power and gas sectors continue to be dictated by a few players, especially Mexico's CFE [Federal Electricity Commission]. Although this has helped anchor demand to galvanize the execution of large-scale projects, it has also inhibited participants' diversification."

RICARDO FALCÓN, research manager, natural gas markets - commodity trading data & analytics, Wood Mackenzie

Chinese counterparts. The current energy landscape in Mexico does not serve that purpose," Adrian Duhalt, a non-resident scholar at the Center for the U.S. and Mexico at the Baker Institute told *Midstream Business*.

For Ricardo Falcón, Wood Mackenzie Research Manager, Natural Gas Markets - Commodity Trading Data & Analytics, there is room for a U.S. piped-gas-to-Mexico-based nearshoring boom, considering Mexico's takeaway capacity at the border with the U.S.

"The challenge here is more associated with the risk exposure and the capabilities of all the Teslas and Amazons of the world who are seeking to enter the Mexican market. To date, price signals and demand growth in the power and gas sectors continue to be dictated by a few players, especially Mexico's CFE [Federal Electricity Commission]," Falcón said. "Although this has helped anchor demand to galvanize the execution of large-scale projects, it has also inhibited participants' diversification. This situation has become more critical in recent years, owing to private investors' perception of increasing non-technical risk, particularly in the political and regulatory frameworks."

In late July, Tesla's CEO Elon Musk said his company would pause development of a $5 billion gigafactory in Santa Catarina, Nuevo León, in Mexico until after the U.S. presidential elections.

Over the coming decades, both the Washington-based Energy Information Administration and the Paris-based International Energy Agency (IEA) expect Asia to take center stage as the growth center for LNG imports sourced from Australia, Qatar, the U.S., and elsewhere—Mexico included.

Gas-hungry Mexico, which until recently also relied on LNG imports, is now betting big on LNG exports, owing to the country's proximity to Texas, which gives it direct access to Permian feed gas. Mexico's five initial Pacific Coast liquefaction projects could offer Permian producers a relief valve for their associated gas and connect the U.S.' cheapest gas to Asia.

Sempra affiliate Sempra Infrastructure, Mexico Pacific, and LNG Alliance Pte Ltd Singapore are leading the five projects that could bring to market around 7.8 Bcf/d or 59 mtpa. According to a recent analysis by Rystad Energy, such volumes could propel Mexico to the ranking of the third-largest LNG exporter in the Americas, trailing only the U.S. and Canada.

But Mexico's ability to achieve LNG exporting glory will not be easy. It will depend on completion of the Pacific Coast-based liquefaction plants as well as pipelines from the Permian to counter supply bottlenecks and even more necessary pipelines in Mexico.

"Natural gas demand in Mexico will certainly increase on the back of additional power generation capacity and LNG exports projects that are expected to come online in the next few years. Nearshoring may also drive demand up as it could lead to a boom in manufacturing activities, especially in border states," said Duhalt, who also is a non-resident scholar at Southern Methodist University's Texas-Mexico Center.

"Without a doubt, Mexico will be under pressure to expand its capacity to transport greater volumes of natural gas, and failing to do so could become a key constraint to meet expected demand increases," Duhalt said. "Politics can also be another factor to consider as the government of [President-elect] Claudia Sheinbaum will have to first recognize how important pipelines are for the country's economic activity and then support the development of this critical infrastructure."

Numerous projects that will add capacity are already underway in Mexico, Rodrigo Rosas, Wood Mackenzie Senior Analyst, Americas Gas Research told *Midstream Business*.

"The CFE anticipates the completion of nearly 4 GW of capacity set to gradually enter operation by 2025. Additionally, with announcements forthcoming, the National Electric Development Program (Prodesen) plans to build a total of 6 GW of combined cycle plants between 2024 and 2027," Rosas said. "Since 2021, gas-to-power demand has been steadily increasing. Power burns have risen by 0.5 Bcf/d, reaching 4.6 Bcf/d in 2024. This trend is expected to continue, with projections indicating a further increase to 4.7 Bcf/d in 2025."

U.S. Natural Gas Exports and Re-Exports by Point of Exit

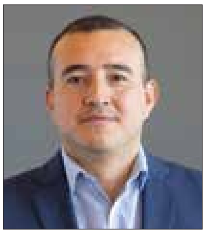
(Million Cubic Feet)

TO MEXICO	2018	2019	2020	2021	2022	2023	2024E	2024E (%)
ARIZONA								
Douglas	0.2	0.2	0.2	0.1	0.1	0.1	0.1	2%
Nogales	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0%
Sasabe	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0%
TOTAL ARIZONA	0.3	0.3	0.3	0.2	0.1	0.1	0.2	3%
Y-O-Y Change %	n/a	-5%	0%	-22%	-38%	-10%	16%	
CALIFORNIA								
Calexico	0.1	0.1	0.1	0.1	0.1	0.1	0.1	1%
Ogilby	0.3	0.3	0.3	0.3	0.3	0.3	0.3	5%
Otay Mesa	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0%
TOTAL CALIFORNIA	0.4	0.4	0.4	0.4	0.4	0.4	0.4	6%
Y-O-Y Change %	n/a	1%	-8%	13%	-3%	-3%	-5%	
TEXAS								
Alamo	0.2	0.2	0.2	0.2	0.1	0.0	0.0	1%
Brownsville	0.0	0.2	0.7	0.9	0.9	1.0	1.1	18%
Clint	0.1	0.1	0.1	0.1	0.1	0.1	0.1	1%
Del Rio	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0%
Eagle Pass	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0%
El Paso	0.3	0.3	0.2	0.3	0.3	0.3	0.3	5%
Hidalgo	0.2	0.3	0.4	0.3	0.2	0.2	0.3	5%
Laredo	0.0	0.2	0.3	0.3	0.3	0.4	0.3	5%
McAllen	0.3	0.2	0.2	0.2	0.1	0.1	0.0	1%
Penitas	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0%
Presidio	0.0	0.1	0.3	0.6	0.6	0.8	0.6	10%
Rio Bravo	0.2	0.2	0.2	0.2	0.2	0.2	0.2	3%
Rio Grande	1.9	1.8	1.6	1.5	1.5	1.6	1.6	27%
Roma	0.5	0.5	0.4	0.5	0.4	0.3	0.4	6%
San Elizario	0.1	0.1	0.2	0.3	0.5	0.6	0.6	10%
TOTAL TEXAS	3.9	4.4	4.8	5.3	5.1	5.6	5.4	91%
Y-O-Y Change %	n/a	13%	8%	10%	-2%	9%	-3%	
TOTALS	**4.6**	**5.1**	**5.5**	**5.9**	**5.7**	**6.1**	**6.0**	**100%**
Y-O-Y Change %	n/a	10%	7%	8%	-4%	8%	-3%	

SOURCE: U.S. ENERGY INFORMATION ADMINISTRATION (EIA)
NOTE: DATA FOR 2024 BASED ON VOLUMES FOR JANUARY-APRIL, WHICH HAS BEEN ANNUALIZED BY HART ENERGY

REESE ENERGY CONSULTING

A Howard Energy gas plant is part of the pipeline system that gathers, processes, and transports gas from the Webb County, Texas, area to the Agua Dulce Hub and into Mexico.



"In addition to the existing infrastructure and production levels, the main advantage of Texas to continue being Mexico's top natural gas supplier is geographical proximity. Given the circumstances, nothing can beat that."

ADRIAN DUHALT, non-resident scholar, the Center for the U.S. and Mexico at the Baker Institute

Texas Dominates Piped-Gas Flows to Mexico

Pemex, which is the world's most indebted oil company with around $101 billion in debt, has struggled to boost Mexico's reserves and production. Mexico has had no other option but to look abroad for necessary gas supply. Expensive LNG imports have been pushed aside for a preference for the advantaged low-carbon, low-cost gas just north of Mexico's border.

Between 2003 and 2023, U.S. piped-gas exports to Mexico followed an impressive upward trajectory, owing to Mexico's positive economic growth. These exports peaked at 6.1 Bcf/d in 2023 compared to just 0.9 Bcf/d in 2003, according to data from the EIA, growing 11% per year on average over this 20-year period. Based on the U.S. piped-gas export data published by the EIA for the period between January and April 2024, annualized by *Midstream Business*, these exports could average 6 Bcf/d in 2024.

Beyond any limitations imposed by Mexico's economic growth—a main pacesetter for natural gas demand—there are constraints to rapid expansion of U.S. piped-gas exports to Mexico, Wood Mackenzie's Falcón said.

"On the U.S. side of the border, supply bottlenecks, localized competition for marginal gas molecules, and price action have affected the deliverability of U.S. pipeline exports to Mexico at different U.S. exit points, especially during peak demand seasons," Falcón said.

"On Mexico's side, takeaway capacity of U.S. piped gas is still significant, considering that the average utilization rate remains roughly at 45% (relative to a nominal 14 Bcf/d)," he said. "However, inadequate system reinforcements and interconnections have limited more liquid transactions between privately run and state-controlled routes, restricting deeper integration of demand centers across regions.

"On top of that, the Mexican natural gas market is yet lacking strategic and commercial storage capacity. Apart from securing better response mechanisms to external shocks, robust gas storage would enhance physical optionality for better supply/demand balancing, which in turn, would give Mexican fundamentals a more stable platform for long-term growth," Falcón said.

Only three states benefit from the uptick in U.S. piped-gas trade with Mexico: Arizona, California and Texas. But this is far from an even three-state race. In 2024, piped-gas exports from Arizona will account for just 3% of the total volume sent to Mexico, with California contributing 6% and Texas supplying 91%, according to *Midstream Business* calculations.

Within Texas, the border cities of Brownsville, Presidio, Rio Grande and San Elizario are on track to account for 65% or 3.9 Bcf/d of the U.S. piped-gas exported to Mexico in 2024. Piped-gas exports from West Texas to South Texas have grown steadily since around 2017, owing to an increase in pipelines that have come into service connecting Central and Southwest Mexico according to the EIA.

Mexico LNG, Infrastructure and Lingering Headwinds

According to Wood Mackenzie's Rosas, "LNG is emerging as the key driver for new demand in Mexico. [New Fortress Energy's] Altamira project has started commercial operation, followed by Costa Azul, set to start in late 2025. Together, these projects will add 0.5 Bcf/d to feedgas requirements." Rosas stressed that growth in Mexico's liquefaction capacity is "contingent on future pipeline network improvements."

The initial five liquefaction plants planned on Mexico's Pacific Coast are being led by Sempra Infrastructure, which is eying three projects (Energia Costa Azul or ECA, Vista Pacific LNG and Salina Cruz LNG), Mexico Pacific Saguaro Energía LNG and LNG Alliance (Amigo LNG, also known as Epcilon LNG).

Sempra Infrastructure has plans for 2 Bcf/d of capacity at its ECA project located in Ensenada in Baja California, Mexico. The project is being developed in two phases: ECA LNG Phase 1 will consist of one train with a capacity of 0.4 Bcf/d, while ECA LNG Phase 2 will consist of two trains and one LNG storage tank and will have a combined capacity of 1.6 Bcf/d.

ECA Phase I is the only project of the five planned on Mexico's Pacific Coast to have a final investment decision (FID) under its belt. Consequently, it is the only project under construction and will be the first to use and export Permian feedgas from a liquefaction plant on Mexico's Pacific Coast.

Sempra is targeting late-2024 for completion of the 188-mile Gasoducto Rosarito or GRO pipeline expansion project in Baja California. The GRO pipeline will have three sections, a compression station with 30,000 horsepower, and capacity to transport 0.5 Bcf/d, according to Sempra Infrastructure. ECA Phase 1's commercial operation date is slated for the spring of 2026.

Sempra's other two planned liquefaction projects are further down the development phase worksheet. Vista Pacifico LNG in Topolobampo in Sinaloa, Mexico, will have one train with 0.4 Bcf/d of capacity, while Salina Cruz LNG in Salina Cruz in Oaxaca, Mexico, a development with Mexico's CFE, will have one train with 0.4 Bcf/d of capacity.

The first phase of Saguaro is the next project to watch after ECA Phase 1, analysts tell *Midstream Business*.

Mexico Pacific, which lists Quantum Capital Group as its controlling owner and lead sponsor, is somewhat overdue to take an estimated $15 billion FID on Saguaro Phase 1, considering promises company executives made to the market in late 2023 related to "imminent" FID announcements.

Mexico Pacific has plans for 4 Bcf/d capacity at its Saguaro project in Puerto Libertad in Sonora, Mexico. Saguaro Phase I will include three trains with a combined capacity of 2 Bcf/d. Similarly, Saguaro Phase II, also comprising three trains, will have 2 Bcf/d of capacity.

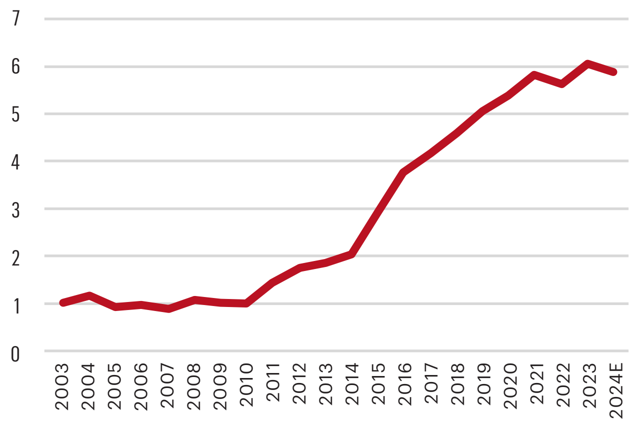
Saguaro will source gas from Waha that will be shipped along the 157-mile Saguaro Connector pipeline on the U.S. side of the border and then the 498-mile Sierra Madre pipeline on the Mexican side of the border. Both segments have capacity to handle 2.8 Bcf/d of gas, according to Mexico Pacific.

In late 2023, Mexico Pacific, GDI Sicim Pipelines and Bonatti executed an engineering, procurement and construction (EPC) contract for the Sierra Madre pipeline project. Under the lump sum, turnkey EPC contract, the GDI Sicim Pipelines and Bonatti joint venture are responsible for the Sierra Madre pipeline, with Bonatti's scope extending to the required compressor stations.

"LNG is emerging as the key driver for new demand in Mexico."

RODRIGO ROSAS, senior analyst, Americas Gas Research, Wood Mackenzie

U.S. Piped-Gas Exports to Mexico (Bcf/d)



SOURCE: U.S. ENERGY INFORMATION ADMINISTRATION (EIA)
NOTE: DATA FOR 2024 BASED ON VOLUMES FOR JANUARY-APRIL, WHICH HAS BEEN ANNUALIZED BY HART ENERGY

"The main constraint we see [for the U.S.] in increasing exports to Mexico is pipeline capacity and the lack of additional sanctioned pipes coming online by 2030," Enverus Intelligence Research senior associate Josephine Mills told *Midstream Business*. With no financial announcements yet from Mexico Pacific, the Saguaro Connector and the Sierra Madre pipelines, "projects are waiting for the Saguaro LNG I facility to reach FID," Mills said.

Wood Mackenzie's Rosas expects Mexico Pacific to announce FID for Saguaro in the second half of 2024 or early 2025.

The lone Asian company in the group, LNG Alliance, has plans for 1 Bcf/d of capacity at its Amigo LNG (Epcilon LNG) project in Guaymas in Sonora, Mexico. The project will be developed in two phases: Amigo LNG 1 will include one train with 0.6 Bcf/d of capacity, while Amigo LNG 2 will have one train with 0.5 Bcf/d of capacity. LNG Alliance has not had much to talk about, but it expects to see movement on the project by year-end 2024.

When it is all said and done, much of Mexico's current nearshoring success and future success in the LNG space will be linked to Texas.

"In addition to the existing infrastructure and production levels, the main advantage of Texas to continue being Mexico's top natural gas supplier is geographical proximity," Baker Institute's Duhalt said. "Given the circumstances, nothing can beat that." ■

MIDSTREAM BUSINESS

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