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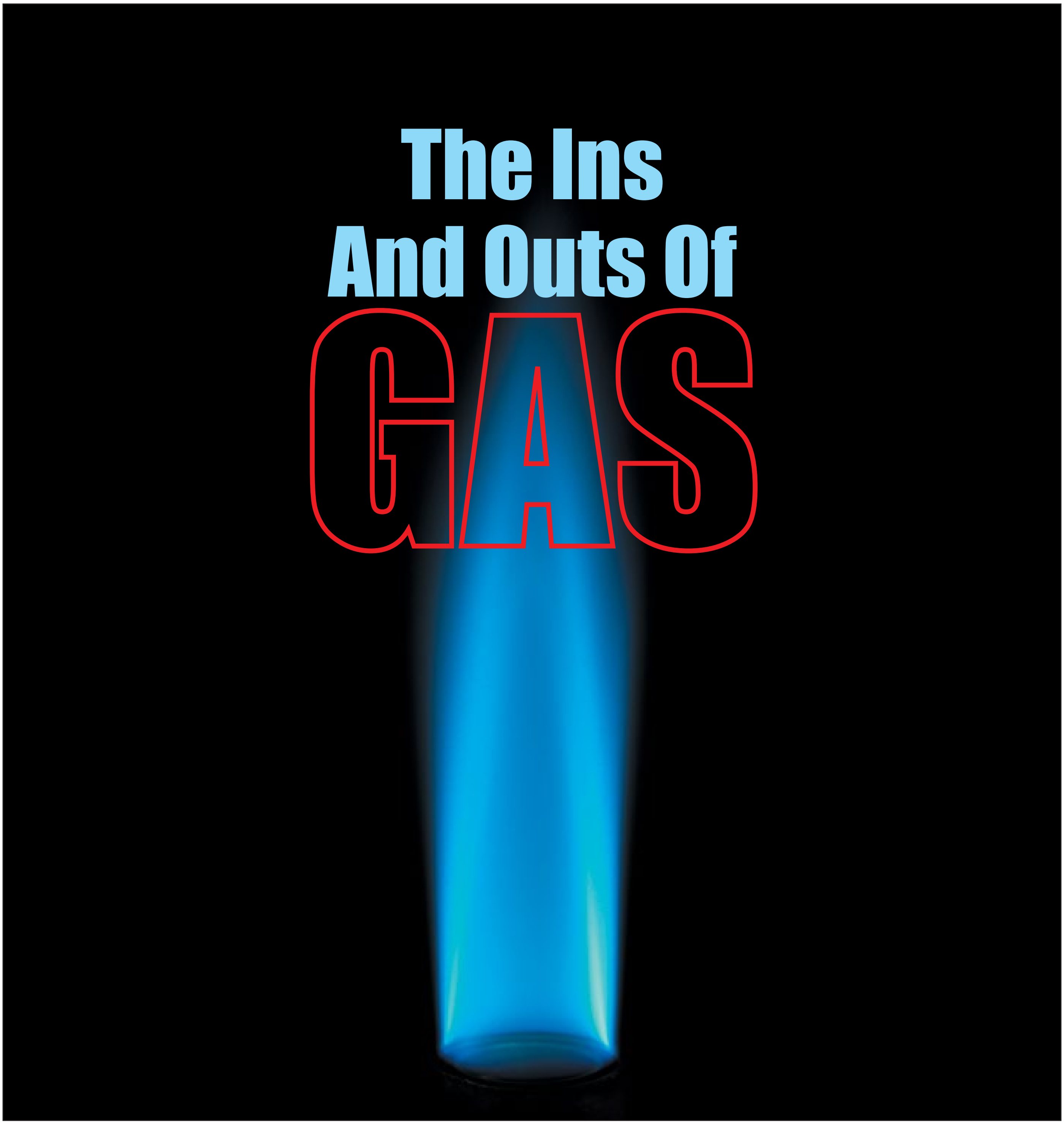

A supplement to Oil and Gas Investor

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A supplement to

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On the cover: The blue flame of natural gas has the potential to burn brighter as U.S. production of the hydrocarbon soars. *Source: Shutterstock/Anton Bryksin*

Editor's Note

Gas

By Paul Hart, Midstream Editor-At-Large

In this issue, we light up the topic of natural gas, which always has been something of the stepchild of the industry. Historically, more money could be made, and made more quickly, when drillers pursued crude oil.

Gas proved troublesome. You couldn't see it, you couldn't sell it without adequate plumbing to move it (the midstream!), and it had a bad habit of blowing up if your tool dresser happened to be smoking a cigar when he walked out on your cable tool's drill floor.

There were and are gas-related safety issues, as contributor Jeff Share notes in these pages. But the industry has taken massive strides to make gas a safe and affordable fuel.

The federal government compounded the gas problem for years by mandating prices that remained artificially low, always just behind what the market would willingly pay for the fuel. Producers ignored it, and, to no surprise, gas reserves dwindled.

Gas proved more trouble than it was worth—literally.

The answer for years proved easy: Flare it. Get rid of it.

Gas proved more trouble than it was worth—literally. The answer for years proved easy: Flare it. Get rid of it.

And that, sadly, remains an answer even today. Crews on the International Space Station have taken multiple photos of gas flares worldwide. This magazine sported a cover in 2013 of the Eagle Ford at night. Bright polka dots lit the South Texas night in what from space appeared to be a gigantic new city between San Antonio and Houston.

New pipeline capacity snuffed the Eagle Ford's flares, but flares burn brightly now to the west in the Permian Basin as producers await new pipeline capacity to link the gigantic basin to markets. What else can you do when Waha Hub prices turn negative? That's right: They have to pay somebody just to take the stuff off their hands.

The Texas Railroad Commission and other regulatory agencies—not to mention royalty owners who welcome fat checks—take a dim view of this, so there are serious inducements to "do something" to get the gas out. It will happen in the Permian; the flares will go out.

Flares have come to life from time to time elsewhere, in the Bakken and Midcontinent, for example. But there are massive flares in the Mideast that provide a "permanent" solution to the gas problem there.

Things changed over time as the industry, and later the public, recognized the value of gas. Research by founders of what is today the GPA Midstream Association established safe and economical ways to separate raw-gas components—propane, butane, etc.—from the methane and laid foundations for whole new industries, which range in size from multi-billion dollar petrochemical plants to patio grills we use to cook burgers on holiday weekends.

Remember: That plastic cup on your desk started off as natural gas somewhere.

Change continues. North America enjoys the best natural gas pipeline grid in the world, and current projects will make it better. The system feeds into burgeoning gas liquefaction plants—another new gas-based industry—that chill methane for easier shipment around the world.

But gas bugaboos remain. The environmental lobby lumps gas into that same dirty category as all other hydrocarbon fuels that allegedly ruin the earth's climate. Berkeley, Calif., recently outlawed new installations of gas infrastructure. Proponents say they hope other cities will do likewise.

On the East Coast, National Grid, the New York local distribution company, has cautioned that it may not be able to hook up new customers unless additional gas transmission capacity to the mammoth, next-door Marcellus and Utica plays gets built.

So challenges remain. But I believe that, more and more, people see natural gas as a positive alternative to coal and uncertain renewable energy sources. The LNG trade grows. The future of gas certainly looks positive from where I sit. Even the federal government, which as noted always seemed to be behind the curve on the gas market, is opening an LNG-dedicated Houston office for the Federal Energy Regulatory Commission to speed consideration of applications.

Perhaps the industry's stepchild will become its heir apparent.

Meanwhile, Hart Energy has several great conferences planned for this fall that will discuss gas issues and much more. Check www.hartenergyconferences.com for more information. I hope to see you there. ■

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For more coverage, visit **HartEnergy.com**.

Keeping Up With Growth

The Permian Basin's close proximity to key markets, like the Gulf Coast and Cushing, Okla., continues to attract midstream energy companies.

By Terrance Harris

An analysis of deals in the third quarter shows that two major interstate pipeline companies, Enterprise Products Partners LP and Energy Transfer LP, announced significant infrastructure plans to bring North American liquids to the U.S. Gulf of Mexico coast—and onward to export markets around the globe.

Furthermore, multiple smaller projects have been announced in all parts of the North American hydrocarbon industry, including Canada, the Midcontinent, the Permian Basin and the Rocky Mountains, as the midstream buildout continues.

Selected projects by region include:

Gulf Coast

Enterprise Products is looking to make a big splash with its plans for three new expansion projects. The company's capacity will increase to load LPG, polymer-grade propylene (PGP) and crude oil from the Enterprise Hydrocarbons Terminal on the Houston Ship Channel.

Nameplate LPG loading capacity will increase from the terminal's current 660,000 barrels per day (bbl/d). A previously announced project, expected to be completed late in the third quarter, will add 175,000 bbl/d of loading capacity. Projects announced in early July will add another 260,000 bbl/d of capacity and are expected to be in service by third-quarter 2020.

The completed projects will increase the terminal's total capacity to almost 1.1 million barrels per day (MMbbl/d) of LPG, or about 33 MMbbl per month.

Enterprise is expanding refrigeration facilities at its Houston Ship Channel terminal by up to an incremental 67,200 bbl/d, or about 2 MMbbl per month, of fully refrigerated PGP. The expansion will allow the company to respond to growing international demand for PGP and offer customers the capability to co-load fully refrigerated PGP and LPG onto the same vessel. The project is expected to be in service by fourth-quarter 2020.

Permian Basin

Solaris Water Midstream LLC is making a major move in the Permian Basin by increasing operations at the Lobo Ranch Produced Water Recycling and Blending Center.

The large-scale produced water cycling and nonpotable water blending facility in Eddy County, N.M, now has the capacity to treat up to 80,000 bbl/d of produced water and receive 80,000 bbl/d of nonpotable water. It can now redeliver a blend of almost 200,000 bbl/d for customer use during well completions.

Additionally, Solaris Water Midstream has also started development of its Bronco facility, which adds another recycling and blending operation in Lea County, N.M.

Solaris Water's recycling facilities are integrated into its Pecos Star System, a more than 300-mile water gathering, disposal and supply system that aggregates produced water from nearly 20 oil and gas operators across a 2-million-acre footprint.

The Bakken

Energy Transfer LP launched a binding supplemental open season for the Bakken Pipeline System.

The crude system, composed of Energy Transfer subsidiaries Dakota Access LLC and Energy Transfer Crude Oil Co. LLC (ETCO), runs from the Bakken to the U.S. Gulf Coast. Incremental capacity, through Dakota Access and ETCO, will depend on committed subscriptions made by shippers during the open season.

Commitments are being sought for transportation service from the Bakken/Three Forks area in North Dakota to storage terminals located in Patoka, Ill., and Nederland, Texas, through their respective pipeline systems.

Rockies

Tallgrass Energy LP's new Hereford Project will support oil production in northern Weld County, Colo. The 30 miles of 12-inch pipeline were scheduled to be finished in July and will offer new volumes for the company to make money transporting crude to market.

During the larger Pony Express' existing open season, sufficient interest arose for expansion capacity from origin points in Colorado and Wyoming to destinations along the system to justify Hereford as a stand-alone project.

The new 30-mile pipeline, the Hereford Lateral, will connect crude oil gathering facilities and/or terminal facilities near Hereford, Colo., with existing Pony Express facilities located near the Pawnee origin facility in Weld County. Pony Express expected the

Hereford Lateral to be in service in July and the expansion capacity on the existing Pony Express system to be in service by May 2020—both ahead of the larger Pony Express system expansion announced early this year.

Canada

Rangeland Midstream Canada Ltd. said it will build the 53-mile Marten Hills Pipeline System in north-central Alberta. The crude pipeline, announced in the second quarter, is expected to come online in second-quarter 2020.

The system is anchored by long-term transportation agreements with three of the region's largest crude oil producers, who have made a combined minimum volume commitment representing 40% of the system's capacity.

Acreage dedications total about 450,000 acres.

Midcontinent

Blue Mountain Midstream LLC has made its name in gas but is now taking baby steps into crude oil.

Blue Mountain entered into an agreement with Roan Resources LLC to gather Roan's crude oil in Oklahoma's Merge play. For Blue Mountain Midstream's first foray into the oil business, it has agreed to a 10-year term covering the 89,000 net acres dedicated area in nine townships in central Oklahoma.

"Blue Mountain continues to grow our relationship with Roan Resources while expanding our scale and capabilities with this fully fee-based business line," said Blue Mountain president and CEO Greg Harper, in a statement. "By adding crude gathering, Blue Mountain can now provide our E&P customers a full suite of midstream services complementing our existing gas gathering and processing and water management services." ■

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Selected Recent Midstream Construction Projects

Operator/Developer	Project	Location	Added Capacity	Play	Status/Completion
PERMIAN BASIN					
Enterprise Products Partners LP	Crude oil pipeline	Midland, Texas, to Houston	N/A	Permian Basin/ Midland Basin	Enterprise has filed permits to build a pipeline that would connect Midland to Houston.
Cogent Midstream LLC	Residue pipeline	Reagan County, Texas	400 MMcf/d	Permian Basin/ Midland Basin	Pipeline will deliver gas from the Midland Basin to Kinder Morgan's Gulf Coast Express Pipeline.
Brazos Midstream Holdings LLC	Natural gas gathering system	Loving, Ward, Winkler counties, Texas	N/A	Delaware Basin	Agreement with Shell Exploration & Production for system that includes 16 miles of high-pressure pipeline.
Longhorn Midstream Holdings LLC	Touchdown Crude Oil Gathering System	Eddy County, N.M.	N/A	Delaware Basin	Open season closed Aug. 14.
Solaris Water Midstream LLC	Lobo Ranch Produced Water Recycling and Blending Center	Eddy County, N.M.	80,000 bbl/d produced water	Delaware Basin	Operations launched in July.
Medallion Pipeline Company LLC	Epic Crude Pipeline	Port of Corpus Christi	10,000 bbl/d	Midland Basin	Open season closed Aug. 16.
GULF COAST					
Tellurian Inc.	Haynesville Global Access Pipeline, Delhi Connector Pipeline	Southwest Louisiana	2 Bcf/d each	Haynesville	Binding open seasons for two proposed pipelines. Both are expected to be in service by 2023.
Lotte Chemical Corp.	Ethane cracker	Lake Charles, La.	1 million tonnes per year	N/A	$3.1 billion cracker dedicated in May.
Enterprise Products Partners LP	Baymark ethylene pipeline network	Bayport, Texas to Markham, Texas	Storage: 600 million pounds; terminal: 2.2 billion pounds of ethylene per year	N/A	N/A
Enterprise Products Partners LP	Enterprise Hydrocarbon Terminal	Houston Ship Channel	175,000 bbl/d	Permian	Operation expected completion late Q3 2019

continued next page

Operator/Developer	Project	Location	Added Capacity	Play	Status/Completion
MIDCONTINENT					
Blue Mountain Midstream LLC, Roan Resources LLC	Crude oil pipeline	Cushing, Okla.	60,000 bbl/d	Scoop/Stack	N/A
ROCKIES					
Meritage Midstream Services II LLC	Steamboat I cryogenic processing plant	Converse County, Wyo.	200 MMcf/d	Powder River Basin	New plant will more than double Meritage's processing capacity in the Powder River Basin.
Tallgrass Energy LP	Hereford Project	Weld County, Colo.	N/A	Niobrara	Open season for 30-mile pipeline that will connect with the Pony Express Pipeline.
Energy Transfer LP, Phillips 66 Partners	Bayou Bridge Pipeline	N/A	N/A	Bakken Shale, Powder River and Permian basins	Expansion open season for certain origin points.
Meritage Midstream Services II LLC	Thunder Creek NGL pipeline	Campbell and Converse counties, Wyo.	N/A	Bakken Shale	Binding open season ended in July.
Energy Transfer LP, Dakota Access LLC, Energy Transfer Crude Oil	Bakken Pipeline System	North Dakota	N/A	Bakken	Open season started July 15.
CANADA					
Rangeland Midstream Canada Ltd.	Marten Hills Pipeline System	North-central Alberta	N/A	Clearwater formation	Crude and condensate pipeline system is expected to come into service in second-quarter 2020.

Source: Hart Energy

The Ins And Outs Of GAS

Problem: **the need for sufficient gas pipeline capacity.**

Opportunity: **serving demand growth.**

By Gregory DL Morris

For natural gas in the Permian Basin, there seems no way out. For gas in the Northeast, there seems no way in.

The outlook for demand growth in power generation and petrochemicals is still positive, but the easy gains are over. Export markets look strong but increasingly crowded. Operators and investors are clearly still keen on the gas midstream, even as they ask critical questions about issues ranging from final end-use markets to the continuing embarrassment of massive flaring.

Gas? It's complicated. But multiple projects and markets could ease the situation.

Marcellus-Utica deals

In June, The Williams Cos. formed a $3.8-billion joint venture with the Canada Pension Plan Investment Board (CPPIB) in the Marcellus/Utica shales that includes two systems owned and operated by Williams: the Ohio Valley Midstream (OVM) in the western Marcellus and the Utica East Ohio Midstream (UEO). The finalization of the agreement, originally announced in March, includes CPPIB investment of about $1.33 billion for a 35% stake in the partnership. Williams retains the rest and operates the combined business.

Williams expects that combining UEO and OVM will create a more efficient platform for capital spending in the region, resulting in reduced operating and maintenance expenses, and develop enhanced capabilities and benefits for producers in the area.

Williams will use the cash proceeds to offset the purchase price of its acquisition of the 38% of UEO it did not previously own from Momentum Midstream. The balance will pay down debt and fund Williams' long list of growth projects. The Tulsa, Okla.-based firm ranks No. 6 on the current *Midstream Business* Midstream 50 list of the sector's largest publicly held firms.

"The funding from CPPIB paid for UEO as well as provided funding for our current growth projects so we did not have to take on debt in 2019," Micheal Dunn, Williams' executive vice president and COO told *Midstream Business*, "and it's a large list [of growth projects]."

In May, the Federal Energy Regulatory Commission (FERC) issued a certificate of public convenience and necessity authorizing the Northeast Supply Enhancement (NESE) project, an expansion of the existing Transco gas pipeline that is designed to serve New York markets in time for the 2020/2021 winter heating season. The NESE project will provide 400,000 dekatherms per day of additional gas supply to National Grid Inc.—the largest distributor of natural gas in the northeastern U.S.

National Grid is converting about 8,000 customers per year from heating oil to gas in New York City and Long Island. According to Williams, "the NESE is critical to make those conversions possible, as well as keep up with new development in the area."

Transco is the nation's largest-volume interstate gas pipeline system, a 10,000-mile network with a mainline running nearly 1,800 miles from South Texas through 12 Southeast and Atlantic Seaboard states. NESE will expand existing infrastructure in Pennsylvania, New Jersey and New York primarily by looping—placing new pipe alongside of existing pipe parallel to the existing right of way.

The project plans about 10 miles of 42-inch line looping facilities, three miles of onshore 26-inch looping facilities, 23 miles of offshore 26-inch looping facilities, the addition of 21,902 horsepower at an existing compressor station, a new 32,000 horsepower compressor station and related appurtenant facilities. According to researchers at Rutgers University's Edward J. Bloustein School of Planning and Public Policy, the design and construction of NESE will generate more than $325 million in economic activity.

Fortress Northeast

With FERC approval in hand for NESE, the last hurdles are state permits.

Williams has resubmitted its permits from New York and New Jersey after having the initial submission rejected "for minor issues," said Dunn. That resubmission restarts an up to yearlong window that regulators have to evaluate the application. Stressing that regulators will take as much time as they need, Dunn said the company "contemplates starting preliminary onshore work this fall, with offshore work beginning next year. We hope to have the project completed in time for the 2020-21 heating season."

"Pipeline bottlenecks because of states' obstruction to expansion projects make steel in the ground all the more valuable," Ethan H. Bellamy, senior research analyst at Baird Equity Research, told *Midstream Business*. "That is especially the case in the Northeast. There are similar risks in Colorado that have made assets in Wyoming more valuable. It still looks like clear sailing for expansion along the major routes from the Permian to the Gulf Coast, with the possible exception of some activism in New Mexico."

Returning to the global macroeconomic level, Bellamy stated emphatically that "switching power generation from coal to gas remains the best way to produce baseload electricity. A negative price for gas in West Texas will bring down global gas prices. That will reinforce the economic proposition for gas over coal—even without considering the particulate and other environmental concerns."

Bellamy also offered some perspective on localized and even regional negative pricing for the resource.

"Oil and gas is still a mining business, and the mining company that wins is the one that can produce the resource at the lowest cost. Given the volumes being flared in the Permian, any beneficial use is literally trash to cash," he said.

The NESE "is incredibly important to the region," Dunn explained. "There are great benefits for National Grid [the regional utility] to convert fuel-oil users in Brooklyn and Long Island to natural gas. That conversion can mean as much as a 50% reduction in annual energy costs for residential customers. It also benefits the airshed in comparison to emissions from fuel oil. The environmental benefits are things that opponents of the project are not talking about, but we are."

The minimal changes required in the permit applications can be taken as a positive sign, Dunn added.

"Regulators were coming up on the one-year deadline for responding to the initial permit applications. If they did

An Atlantic Sunrise construction crew works along the pipeline's right-of-way in Pennsylvania. The project added 1.7 million dekatherms per day of capacity to the existing Transco gas transmission system, moving production out of the booming Marcellus play to customers. *Source: The Williams Cos. Inc.*

not act before the one-year deadline, they would have waived their rights to issue a [Clean Water Act Section] 401 water quality certification, so they had to act. We responded quickly to their requests and are hopeful they will process the current applications timely in order to allow construction to begin this fall."

Chink in the armor

Interests opposed to hydrocarbon fuels in general—and gas produced by hydraulic fracturing in particular—have found pipeline permits to be an effective point of resistance. As noted by industry leaders and analysts, it is easier and less expensive to get Marcellus ethane 3,000 miles by tanker to Europe than it is to get Marcellus methane 300 miles by pipeline to New England.

"It is less expensive to build pipelines underwater in the Gulf of Mexico than it is to build on land in Pennsylvania, New Jersey or New York," Dunn lamented.

"We are doing what we can to balance the debate," he said. "Our industry has mostly been out-of-sight, out-of-mind. It used to be that a certification from FERC was sufficient to proceed. Now we are doing more outreach. The Atlantic Sunrise project was a great example of that. We got all stakeholders involved."

In September 2018, Williams was recognized by the International Association for Public Participation (IAPP) for collaborating with the public and other stakeholders during the planning phase of the Atlantic Sunrise pipeline project. The IAPP is an international federation of professionals in 26 countries working to advance the practice of public participation.

During the planning phase of the nearly 200-mile Atlantic Sunrise Pipeline, Williams collaborated with landowners and other stakeholders to adopt approximately 400 changes affecting more than half of the originally designed, greenfield route. The company used public meetings, contact with local officials, community leaders and affected landowners to identify and attempt to resolve issues or concerns prior to submitting its federal certificate permit application.

The project's public engagement efforts also included the development and implementation of a voluntary $2.5 million environmental stewardship program designed to benefit resources and support communities within the Atlantic Sunrise project area.

IAPP judges said Williams' work on Atlantic Sunrise helped raise the bar in the field of public engagement, "setting a new standard" for the pipeline industry.

"Investing one-on-one time for effective stakeholder relationships is an integral component of successful public outreach," said Mike Atchie, public outreach manager for Williams.

The Atlantic Sunrise project was designed to expand Williams' existing Transco pipeline to connect abundant Marcellus gas supplies with markets in the Mid-Atlantic and southeastern U.S. It went into service in the fourth quarter of 2018.

Still, "all politics is local," as former Speaker of the House Thomas Tip O'Neill (D-Mass.) once observed. Greg Haas, director of integrated energy at Stratas Advisors, a Hart Energy company, cited a recent situation where local politics cut in favor of gas. "A Northeast utility declared that because it could not get additional incoming gas pipelines built, no new residential connections would be made and all commercial customers would be locked into their existing volumes, or less. That was a serious threat to the growth of local businesses."

Suddenly, people clamored for more gas. "It became a pocketbook issue to residents—taxpayers and voters—as well as to businesses," Haas told *Midstream Business*. "The opposition to the pipeline blockaders became very vocal. When you threaten local development, even home renovations, people get upset."

While certainly not advocating brinksmanship on the part of utilities, Haas anticipated that "We are going to see more limits on gas at the burner tip if politicians do not allow more gas to get to consumers. In most cases, the blockaded development is not limited to greenfield pipe, but also to simple looping or other expansion projects on existing lines in their rights of way."

"But I am a little uncomfortable about so many companies relying so much on exports to Asia. Not the least because we don't have good data on the region."

– **Christopher Sighinolfi**, *managing director for gas, utilities, midstream, and refining, Jefferies Group LLC.*

Flagrant flaring

At the opposite end of the country, the opposite problem prevails. Haas likens questions about getting gas out of the Permian to the family road trip where one or another of the kids keeps asking, 'Are we there yet?'

"I don't think we are ever going to get there," said Haas. "We need 1.5 to 2 billion cubic feet per day (Bcf/d) of new transportation out of the Permian every year through the middle of the decade. There is some capacity coming on later this year and into next. So instead of asking 'are we there yet,' the better question is, 'how much more do we need to add each year?' We are on a treadmill."

Control has become a little more evident in one important aspect of Permian production: the profligate flaring that has plagued the play for years. States are now doing the control that has been missing.

In contrast, there does not seem to be much constructive regulatory movement in the Northeast. "There is a lot of activism in all the statehouses," said Haas. "A lot of politicians believe that blocking fossil fuel is a winning ticket, especially in New York and New Jersey."

No snowballs

One extreme example was a few years ago when Vermont banned hydraulic fracturing. There are about 35 states with commercial hydrocarbon reserves, but the Green Mountain State is one of the few that does not. So Vermont banning fracking is very much like Saudi Arabia banning snowball fights.

It bears mentioning that the first flaring permit challenge has come from a midstream company, with Williams challenging a permit application by Exco Resources Inc. The producer claims it is cheaper to flare than to pay for gathering and processing.

"The business and regulatory question is what to waste, money or molecules?" said Bellamy.

That is just one challenge, but Bellamy suggested it is only a matter of time until those opposed to flaring start challenging every permit. If every producer had to defend every flaring permit, there would have to be changes in the way industry makes its economic assumptions.

"We just had a call with a major industry executive," Bellamy added. "He agreed that large-scale flaring is a black eye for the industry and called for more regulation of the practice. It is reasonable that a producer ought to have a plan for getting associated gas to a pipeline as part of any development project."

Calls for regulation on the issue also make sense in the interest of keeping the playing field level. Companies that take stewardship should not be at a disadvantage to their more profligate competitors.

Because of midstream constraints, the price of gas in West Texas has recently dipped into negative territory.

"If producers can flare it, the value is zero, so I guess that is an upgrade," David Foley, senior managing director and chief executive officer at Blackstone Energy Partners, told *Midstream Business*. "That is the current reality, but

Williams "contemplates starting preliminary onshore work this fall, with offshore work beginning next year. We hope to have the project completed in time for the 2020-21 heating season."

– **Micheal Dunn**, *executive vice president and COO, The Williams Cos. Inc.*

it isn't good for the environment, and I think it is a temporary anomaly. All that it says is that we need more pipelines. Nature abhors a vacuum, and the market abhors a wide differential.

"The crude differential is likely to be alleviated later this year. We need another dry-gas pipe, and also NGL takeaway, perhaps to a different destination than [NGL hub] Mont Belvieu. That could be anywhere on the Gulf Coast where there is petrochemical manufacturing," he added.

Global NGL demand

Even as midstream operators labor to get molecules to market, the looming strategic question beyond domestic pipeline bottlenecks is continued demand. "Gluts flow downstream," said Haas. The bonanza in gas, especially rich associated gas, has already created a surfeit of NGLs too.

"The glut in ethane and propane is already rolling downhill to the North American polymer market. The place of last consumption is the end user," he added. For NGLs into polymers and gas into LNG alike, the final frontier seems more and more to be exports.

Haas made a presentation at Hart Energy's recent DUG East Conference in Pittsburgh on exactly that topic.

"I came away from that event noticing that attendees were rightly wondering where the demand would be coming from," he cautioned. "Producers have stopped drilling so hard, but they are still converting their DUCs [drilled but uncompleted wells], so production continues to rise. Upstream and midstream operators have to think through where all that gas is going to go."

The ready answer seems to be LNG exports (see the adjoining story).

Backing out coal

Gas replacement of coal-fired electrical generation is taken as a given, especially in North America and Europe, with vast potential in the rest of the world. That is true, but not unalloyed. There is some purely political pushback for coal under the current U.S. administration, but the bigger concern is that the low-hanging fruit has already been claimed.

There are still many retirements of coal-fired power, but with wind and solar now well established and even setting the incremental cost of generation in some wholesale regions, gas cannot assume every coal kilowatt lost is a gas kilowatt gained.

Overseas, the problem is the opposite. Both India and China have extensive plans for new coal-fired power. That plays to their own nationalistic interests, in the use of domestic fuel sources and minimized dependence on imported fuels.

"Even with coal disfavored in North America and Europe, we don't anticipate $3 gas until the middle of the decade," said Haas. "Prices had been $2.60- to $2.70 per thousand cubic feet, but that has sunk dramatically to about $2.30. That is below average relative to sub-average storage levels for early summer that presently exist. And, we have seen above-average storage injections this year, because of growth in production already noted, as well as delays in LNG exports."

Those delays do not reflect serious problems, only normal slippage in schedules for construction and startup. Still, the situation has led to billions of cubic feet being put into storage, said Haas.

He reiterated that the strategic, even macroeconomic, question for all North American hydrocarbon producers is, "'Where is the ultimate demand going to be?' We see potential gas demand for fuel worldwide, also as a raw material for fertilizers and petrochemicals. There is industrial demand for the renewed glass and steel industries. Low gas costs should make this a profitable year for those companies."

Upping the ante

Blackstone's Eagle Claw Midstream LLC, active in the Permian's Delaware Basin, is a prime example.

"Since our original investment in Eagle Claw, that operator has tripled the acres of production dedicated to it to now well more than 600,000," said Foley. "It has also tripled its pipeline miles to 1,100 and quadrupled its processing capacity to 1.3 Bcf/d. It is significantly larger than the second-largest private operator. The customer count has now increased significantly, including some very large acreage dedications from supermajors. We are at the scale where we can be of service to the largest producers."

Most of that has been done through organic growth that has been augmented by acquisitions. Those, notably of CapRock and Pinnacle, have allowed Eagle Claw to expand into water and even a bit of crude. Water is extremely important because, as Foley noted dryly, "you can't flare water."

Growth in the Permian midstream is not just about expanding operations and one's customer base, Foley explained.

"It is not just playing the hand that you are dealt. It requires active

Meritage Midstream will more than double natural gas processing capacity on its system in the Powder River Basin with construction of a new, cryogenic processing plant located in Converse County, Wyo. The plant will be served by a 20-inch trunk line that connects to Meritage's Thunder Creek Gas Services. The Steamboat I plant also will be connected to Kinder Morgan's Wyoming Interstate Co. LLC pipeline for residue gas. NGLs flow to Phillips 66 Co. and ONEOK Inc. *Source: Meritage Midstream*

management, increasing your bet and drawing more cards—really working it."

The genesis of several of Blackstone's recent midstream investments came from Foley's frustration over the lack of producer discipline contributing to continued declines in natural gas prices.

A 'rocket ship'

"We believed that incremental production of natural gas associated with oil wells in the Permian Basin was going to grow at a rapid rate, a rocket ship really, representing more of the growth in U.S. gas production than from any gas-focused basin. It's very hard to make money producing gas if the most active drillers are the ones who don't care about the gas price because it is a byproduct of their oil production.

"We saw that existing midstream infrastructure was going to be inadequate and that basis differentials for natural gas and natural gas liquids in the Permian were going to blow out and create attractive opportunities to invest in the construction of new pipelines, processing and export facilities," he added.

Foley sees continued growth in petrochemicals capacity, led by supermajors such as ExxonMobil Corp. "We have about 30 million metric tons per year [elsewhere referred to as million metric tons per annum or mpta] of ethylene cracker capacity now," he said, "There is another 4.5 MMt/y coming into service this year and a further 4.8 MMt/y in 2020 and beyond. That is a 30% increase in a little more than two years."

Foley also noted with satisfaction that, "We were the first and largest investor in Cheniere's LNG export complex at Sabine Pass [La.], investing $1.5 billion back in 2012 that was critically needed to start construction of the facility."

That initial investment has since converted into equity ownership of Cheniere Energy Partners that is worth approximately 5 times more than Blackstone's cost basis. In addition to the massive and still-growing liquefaction capacity, Cheniere has 20-year take-or-pay contracts with global major customers and pays a healthy cash dividend.

Foley anticipates the gas sector, both domestically and internationally, will undergo the same disintermediation as the oil sector did in the later decades of the 20th century. "It will be in fits and starts, but gas will be more actively traded."

Electrons and molecules

One of the great frustrations of potential in the gas market has been Mexico. For years now, players have lamented that gas, which is much needed in Mexico, has adequate capacity to get to the border, but the pipeline network within Mexico necessary to deliver the gas has experienced significant development delays.

There is equal vexation in Mexico, which finds itself importing LNG at higher, global prices. One innovative approach is moving downstream all the way to generation.

"Sometimes it is easier to export electricity than natural gas molecules," said Foley. "We have a power plant on the border. We are buying gas at U.S. domestic discounts and selling electricity at Mexican premiums."

One wrinkle in the grand plan to turn light liquids into olefins and then into polymers to ship to Asia is that there are companies in China and elsewhere in the region that want to produce plastics locally, and there are companies in the U.S. keen to sell them both alkanes and olefins.

"China has projects to take U.S. ethane to produce olefins and polymers," Andrew Reed, principal and head of NLGs at ESAI Energy, told *Midstream Business*. The demand is growing, but, Reed added, "There is not room for all

"Pipeline bottlenecks because of states' obstruction to expansion projects make steel in the ground all the more valuable."

– **Ethan H. Bellamy**, *senior research analyst, Baird Equity Research*

of this. There is an over-exuberance about the export market. The early movers among the exporters along the Gulf Coast are probably safe. Naphtha exports will probably be the first to feel the pressure."

According to ESAI research, China has 35 mtpa of new ethylene capacity announced for this year through 2024. Some of that will be delayed, and some will be cancelled, but a significant amount will be completed.

In the same timeframe, the U.S. is adding about 10 mtpa of steam cracker capacity, onto a base capacity of about 34 mtpa. Global demand increases about 6 mtpa, which would total 30 mtpa through 2024. The announced plans for the U.S. and China alone—never mind any further announcements or incremental increases of existing facilities—is already 45 mtpa.

"Clearly, the world is not ready for this much," said Reed. More broadly, he added, "From an NGLs perspective, we are coming from a bottleneck situation in terms of takeaway, fractionation and LPG export terminals and quickly moving to build out capacity that will move ahead of export markets. That is especially true in LPG. Demand will adjust to the new supply, but that demand cannot grow fast enough to support the amount of exports already planned. I often perceive that some of the production and export plans fail to take into account the export market realities."

There are some incremental increases possible from domestic demand, but the only viable volume markets are international: notably household use in Southeast Asia and petrochemical demand worldwide. Tanker utilization is likely to increase, but it is not yet clear if additional bottoms will be needed.

"No one demand sector will be able to lift LPG," said Reed. "It will take all downstream developments from PDH to household use."

Choppy, episodic

Electric power has indeed offered the lion's share of gas demand for the better part of the past decade at the expense of coal-fired installed capacity, noted Christopher Sighinolfi, managing director for gas, utilities, midstream and refining at Jeffries Group LLC.

"But the low-hanging fruit has been gathered. Renewables have lowered their cost structure and increased their rates of growth, albeit from a low base. They have now reached double digits in terms of capacity composition, so from now on growth [for renewables] will have a more measured pace," he told *Midstream Business*.

Most analysts also expect that there will be further retirements of coal-fired power, but the pace of their replacement will be slower than in recent years. If at the same time renewables have established themselves as a major source of baseline power, the only other likely segment would be nuclear.

"I recently spoke with Neil Chatterjee, chairman of the FERC, about the nuclear fleet," said Sighinolfi. "Nuclear power is carbon-free and provides stable, high-paying jobs. But for many other reasons it does not totally jibe with the outlook of the environmental community, most notably because of the persistent question of what to do with spent fuel. There is also the shadow of Fukushima."

Given the unknowns, the simplest outlook is back to gas replacement of coal. "Gas versus coal is straight economics," said Sighinolfi. "From now on it is likely to be choppy, very episodic," driven by the relative prices of the fuels and other regional factors.

This puts even more emphasis on exports—of LNG, or NGLs, or polyolefins, or even crude.

Which makes Sighinolfi uneasy.

"A lot of people have pivoted to exports as the answer. We hear it in every company presentation. Now a case can be made about the relative imbalance in energy consumption in Asia as compared to Europe or North America. But I am a little uncomfortable about so many companies relying so much on exports to Asia. Not the least because we don't have good data on the region. People are used to the data we get from the Energy Information Administration in the U.S. That level of insight does not exist in other parts of the world. As soon as you export, the data get much less clear. At the same time you are in competition every day with other fuels or feedstocks and other producers."

Of course, there is also the question of how many companies can be profitable all exporting the same stuff to the same region. "A lot of companies are banking on Asian GDP to clear the U.S. market," he said ruefully. At least for gas, Sighinolfi is sanguine. "Even with coal growth in India and China, there are opportunities for gas growth as well. There is a benefit for the midstream in providing throughput for export.

"That said, the elements that have exposure to price are not in as strong of a position." ■

Gregory DL Morris is a freelance writer based in Chapel Hill, N.C., specializing in energy and petrochemical topics.

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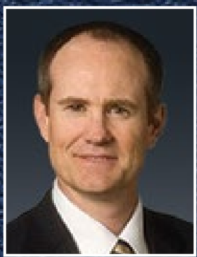

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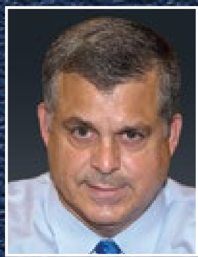

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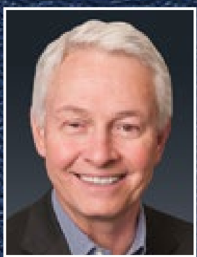

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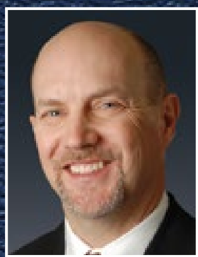

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A new era dawned for the U.S. natural gas business with the advent of large-scale LNG exports in 2016. The LNG marketplace will change substantially in coming years as the nation becomes the world's largest LNG supplier. *Source: Shutterstock/By Wojciech Wrzesien*

To Market, To Market

The world wants America's LNG, but who the customers are, and where, will change.

By Paul Hart

Head north out of Kenai, Alaska, on the Kenai Spur Highway and spectacular scenery glows around you on a sunny autumn day.

Cook Inlet lies to your left, and it's not uncommon to see the towering Redoubt volcano across the way puffing a steam cloud. The big mountain's snow-capped beauty gets lost on locals, who painfully remember when the mountain exploded 30 years ago, coating the Kenai Peninsula in thick ash. The stuff was so fine it could pass through automobile air filters, and not a few engines suffered the consequences. The mountain grumbled again in 2009.

To the right lies the forest primeval. Oh, watch for moose trotting along the road, especially at twilight.

But the breathtaking scenery breaks into something resembling the very industrial Houston Ship Channel as the highway enters the settlement of Nikiski—a fertilizer and cogeneration operation, ship docks and a refinery. Between them lies an unusual looking plant with three large, white and fully insulated tanks.

Quiet nowadays, this is the Kenai LNG plant, the nation's first stab at liquefied natural gas (LNG) exports, built to supply Japanese customers. This was the largest gas liquefaction plant in the world, with a capacity of 200 million cubic feet per day, when a Phillips Petroleum Co. and Marathon Petroleum Corp. joint venture opened the plant 50 years ago. That ranks smallish by today's standards.

Then and now

By comparison, Cheniere Energy's Sabine Pass plant in Cameron Parish, La., can process 4 billion cubic feet per day (Bcf/d).

Plant operations ended in 2015 as gas reserves trailed off in the Cook Inlet fields that feed it. Alaska's citizens want to keep the remaining gas to serve Anchorage.

Oddly, Marathon Petroleum, which now owns the plant outright, as well as the nearby refinery that it gained in its 2018 purchase of Andeavor (Tesoro) Corp., has explored converting the plant to an import facility to provide gas to fuel the refinery's operations.

But if this corner of Alaska's gas business remains quiet, the rest of the world's gas business is booming, and the U.S. will become a much-larger player.

Kinder Morgan Inc. projected in a second-quarter investor presentation that U.S. LNG exports will rise from 3 Bcf/d in 2018—3.4% of domestic gas demand—to 17 Bcf/d in 2030—14.3% of domestic demand.

Kinder Morgan, No. 3 on the *Midstream Business* Midstream 50 list of the sector's biggest publicly held players, will watch the trend closely. The presentation noted that 40% of all U.S. gas moves through one of Kinder Morgan's own pipelines. The corporation also is developing the Elba Island LNG plant near Savannah, Ga.

Worldwide demand for natural gas grew 4.6% in 2018, its fastest annual pace since 2010, according to the International Energy Agency's (IEA) *Gas 2019* report. Gas accounted for almost half the increase in primary energy consumption for all fuels, according to the IEA.

> "The biggest problem China has right now is that the regasification facilities are, even though owned more broadly, all in the hands of basically just two or three companies."
>
> – **Brian Bradshaw**, *partner, Sidley Austin LLP*

Rising demand

And that gas-heavy trend likely will accelerate, the IEA predicted. Gas demand is expected to rise by more than 10% over the next five years.

"Supplies to meet growing global demand for natural gas will come from both new domestic production in fast-growing economies but also increasingly from major exporting countries, led by the development of abundant shale gas resources in the United States," the IEA said in its summary of the report. "The strong growth in LNG export capacity will enable international trade to play a growing role in the development of natural gas markets as they move towards greater globalization."

The IEA said the U.S. will be the world's largest exporter of LNG by 2024, jumping past Australia and Qatar, shipping 100 billion cubic meters (3.5 trillion cubic feet) per year. That's estimated to be one-eighth or more of all the gas the nation produces annually.

The whole LNG market will change radically in the next few years, S&P Platts said in a third-quarter report entitled *New Horizons: The Forces Shaping the Future of the LNG Market.*

"Growing, flexible U.S. volumes and new supplies from Qatar, Russia and emerging producers will open up new LNG trade flows and reinforce global interconnectivity in the 2020s, reducing overall voyage lengths, lowering delivery costs and creating fertile ground for the development of spot and risk markets," the report said. "But there are conflicting forces: Just as LNG occupies a more central role in national energy and economic strategies, it has also become increasingly exposed to trade battles that could fragment trade flows."

Traditional long-term, point-to-point deals between one LNG producer and one LNG customer will disappear. Liquefied gas will become more like its crude oil cousin—an actively traded commodity—with spot market and rapidly changing deals. That will help draw in new players at both ends of the market, those who have sat on the sidelines, given the extravagant costs of both liquefaction and gasification.

Where to?

Where will those growing gas markets be? There will be significant shuffling in the LNG customer mix, but the one to watch will be China, Brian Bradshaw, partner with Sidley Austin, told *Midstream Business*.

The IEA noted that, in addition to a new export leader—the U.S.—there will be a new top importer: China.

Wells Fargo noted in a recent analysts' report on LNG that, in the first three years since the start-up of Cheniere Energy's Sabine Pass liquefaction plant in Cameron Parish, La., South Korea has received the most tankers loaded with U.S.-produced LNG. But industry observers point to South Korea's neighbor as the big—and getting bigger—LNG buyer.

"China's going to be the largest buyer of LNG," Bradshaw said. The Asian giant faces significant air pollution problems, and LNG represents one answer to that challenge.

"Yianjing, China, is on the coast, and they have a huge industrial park there," he cited as an example. "All of the coal-fired power plants have to be converted [to gas]. Just the amount of coal-fired power plants that need to be converted is very significant," over and above any prospective for China's industrial growth.

One challenge China and its LNG suppliers face is the limited number of Chinese LNG import players—and their limited landing infrastructure, he added.

"The biggest problem China has right now is that the regasification facilities are, even though owned more broadly, all in the hands of basically just two or three companies," Bradshaw said. "It's unclear how your LNG is going to be landed in China. You have to be talking to someone who has real access to the capacity."

"But they have to convert," he explained, referring to the major air pollution problems in large Chinese cities. "If you spend any time in Beijing, you can appreciate the need to diversify from the coal-fired power plants. It's going to happen; it has to happen.

"It's just if the LNG will be coming from us or will it be coming out of Qatar or Australia? We have to decide where the United States ranks in the list of suppliers."

China takes the lead

Moody's Investor Service projected the same trend for the Chinese market in an investor report published as the third quarter began.

"Natural gas demand is likely to grow in all regions worldwide, led by China, which is likely to account for over 40% of global demand growth through 2035—largely for environmental reasons," it said. "Chinese demand developments will increasingly dominate the price signals for traded natural gas markets globally."

Greg Haas, director of integrated oil and gas for Stratas Advisors, agrees that China will be the key LNG market. He added a challenge: the rumbling trade war between the U.S. and the Asian power.

"First and foremost, hopefully this trade war with China gets rectified amicably," Haas told *Midstream Business*. "From the perspective of LNG, that is probably the number-one market on the planet for growth of metric tons of LNG." The trade dispute, "I think for the rest of this year it might be a little bit of a problem, but hopefully by 2020, and then for 2021 through 2023, we'll see a more normalized view towards U.S. LNG exports, because we'll certainly have the capacity to help to fulfill their needs."

Bradshaw said South America represents another emerging market for U.S. LNG, a region where Gulf Coast plants enjoy an advantage due to comparatively short voyages relative to other suppliers in the Middle East or Australia.

Coals to Newcastle

There are other potential new LNG markets out there, including some surprises. In a classic coals-to-Newcastle deal, Saudi Arabia's Saudi Aramco signed a 20-year agreement to buy 5 million metric tons per annum (mtpa) from a Sempra Energy plant now under construction at Port Arthur, Texas, and also will take a 25% equity stake in the first phase of the project.

The deal will allow Aramco to build on its plans to become a major player in global LNG trade. The firm also plans

Where it all began: Now mothballed as Cook Inlet gas reserves decline, the Kenai LNG plant sparkles at sunset on a brisk Alaskan winter day. It was the first LNG export operation in the U.S. when it went on stream in 1969, built to serve Japanese utilities. *Source: ConocoPhillips* to significantly expand its own gas production, including recent offshore discoveries in the Red Sea.

Also, the kingdom needs gas to meet soaring domestic consumption, Ahmad Al-Sa'adi, senior vice president of technical services at Saudi Aramco, said in a recent interview.

Elsewhere, "I think India will continue to be a buyer, and that will become the second-largest market" after China. "I think Japan will likely be a good market as well as South Korea," Haas said.

But India, like China, has infrastructure challenges. A recent article in *LNG Condensed* noted, "While the government is pushing its city gas program hard, protracted delay is the norm rather than the exception, casting doubt on the rapidity with which Indian LNG demand can grow."

The Wells Fargo analysis noted that President Trump and Vietnam's Prime Minister, Nguyen Xuan Phuc, issued a statement following the June G20 economic summit in Osaka, Japan, that the two countries intend to negotiate an LNG sales agreement. Vietnam has announced plans to build its first regasification terminal in a deal with South Korea's Samsung. Vietnam also has deals in the works for Russian LNG coming from Siberia.

"First and foremost, hopefully this trade war with China gets rectified amicably. From the perspective of LNG, that is probably the number-one market on the planet for growth of metric tons of LNG."

– **Greg Haas**, *director of integrated oil and gas, Stratas Advisors*

Europe

Western Europe represents a significant LNG market, given the region's developed economies, environmental concerns and declining North Sea production. Renewables, thanks to a strong environmental movement, likely will provide a significant share of European power and heating needs.

"With extensive regasification and storage capacity, flexible demand and liquid trading options, Europe is steadily cementing a key role in the global LNG market. It is emerging not only as a global balancer, but also as a demand center in its own right, price anchor, and 'put option' due to its ability to efficiently redirect cargoes or absorb surplus volumes in times of oversupply, a market condition that is likely to reappear in the mid-2020s," the Platts report said.

The Bahamas-flagged *Asia Vision* has the distinction of carrying the first commercial LNG shipment, bound for Brazil, from Cheniere Energy's Sabine Pass plant in early 2016. *Source: Samsung Heavy Industries*

That's good news for LNG exports, according to Moody's.

"Natural gas exports to Europe are likely to keep growing as it pursues carbon-reduction efforts, as its indigenous sources of supply diminish, and as its dependence on Russia raises energy security concerns," its report said.

"There was a big push to get renewables, but you can't run an entire economy off renewables," Bradshaw said. "There's too much variability if the sun doesn't shine or the wind doesn't blow. You still have to have some sort of carbon-footprint power plant, and gas-fired [power] is the best thing going."

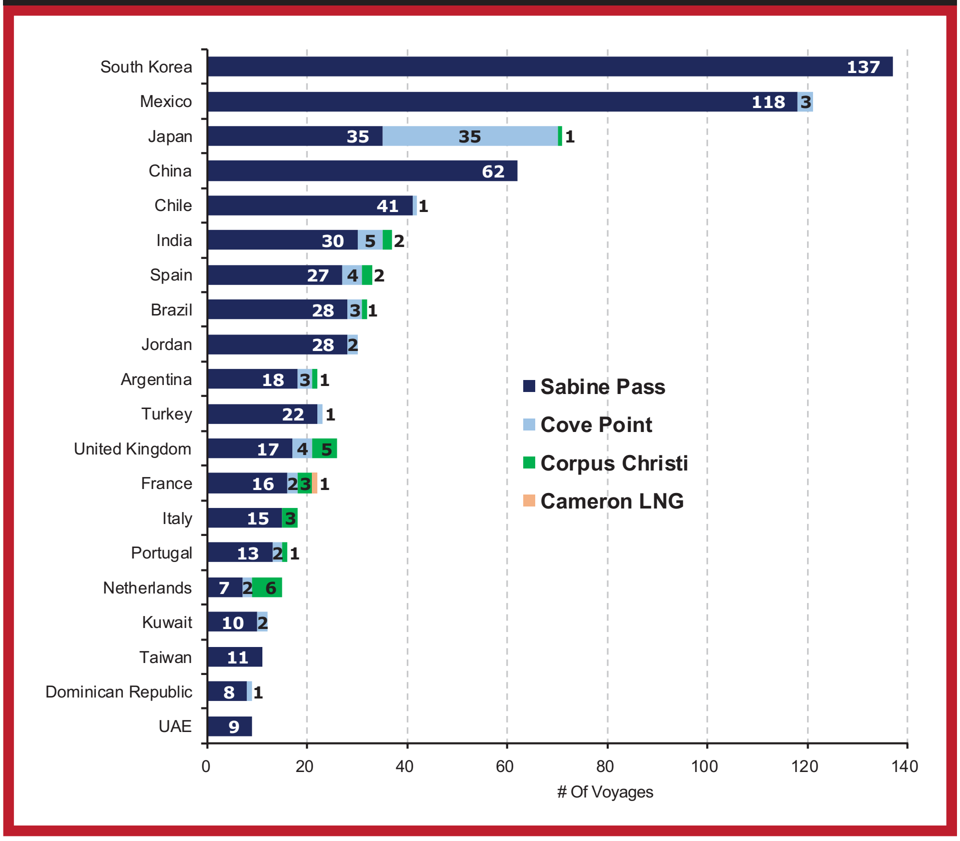
The Atlantic Basin has a well-developed LNG market with two pricing points, in the Netherlands and U.K. But those positives are offset in great part by Russia.

Russia's pipes

"Russia can turn on their pipelines and bring as much gas as they want in, coming across Europe, and that really drives the price down," Bradshaw said, "although there is the very real threat that Russia can jack up prices—or shut in pipeline flows—on a moment's notice."

U.S. LNG exports could get a boost if President Trump follows through on potential sanctions imposed on the

U.S. LNG Shipments By Destination, 2016-2019



Sources: Bloomberg, Wells Fargo Securities

Nord Stream 2 pipeline project between Russia and Germany. There's divided opinion in Europe on the project, with some—particularly the Nordic and Baltic countries—concerned that it would increase the continent's already heavy dependence on Russian gas. But the project enjoys considerable support in Germany, which is seeking stable gas supplies.

"It's all geo-political. People are concerned with what is Russia going to do, what is China going to do and what's the United States going to do? All of those things impact how ultimately it plays out," he added. "If you're a local distribution company or you have a gas-to-power project you're trying to do in Brazil, you're still getting swept up into what's the first market and what it's going to go to, what's the second market, and how pricing works in those markets because that's going to really push how pricing's going to work in your market as a secondary or tertiary market for the big off-takes."

It's complicated

Who buys from whom is a complex business, Bradshaw explained.

"The biggest problem with all of this is you can't talk about just one issue because it involves a whole cluster of issues. If one of the things changes, it impacts everything, so how you price depends on will it go to, say, Europe? If it's going to Europe, that's going to make the prices go higher in Asia," he said. "Fundamentally, there are still the Atlantic Basin and the Pacific Basin, and they're priced differently, and they work differently.

The world's two major canals, the Suez and Panama, serve as pricing points due to the limits they place on tanker size.

"This has affected trade for the last thousand years," he added. "If you have to go all the way around South America or Africa, you've got a long, long haul. It means you price things differently. People don't like to do that."

Profitability

Liquefaction plants, tankers and terminals represent big, multi-billion dollar investments, and there has to be a return on investment for the firms building and operating them. That is a major concern right now—wherever the customers may be.

"Another thing that's limiting current exports, or penetration around the planet's market places, is the potential for negative netback," Haas cautioned. "That means by the time you buy the gas, liquefy the gas, load it up in a ship, move that ship across the seas to wherever the buyer is, and then regasify it, then move it to end place markets, the netback to the selling entity in the U.S. is in many cases negative these days.

"It's a money-losing proposition to go very far these days with a lot of natural gas—especially for the stock market [investors]," he added.

Tellurian Inc. rated its cryo-spread—calculated by subtracting the NYMEX Henry Hub price from the premium LNG netback to the U.S. Gulf Coast—at a thin 97 cents per million British thermal units (MMBtu) for August contracts.

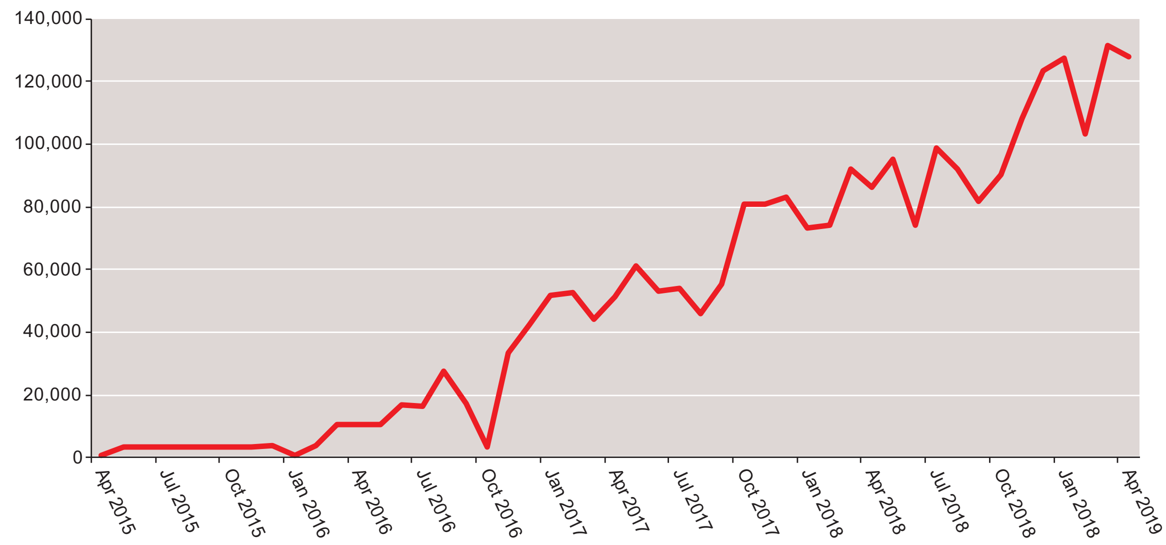
All of this tends to make European markets the more likely customers for U.S. plants, given the comparatively shorter tanker sailings across the Atlantic.

"But I'm even hearing negative netbacks are starting to pop up in Europe from the U.S.," Haas said. Russia plays a big role in the market for both economic and political reasons.

"I have not tracked globally that [Russian] dynamic, but it would make sense, to the extent that Russia has the capacity with its pipelines and the capacity to send out its gas production," he added. "It makes sense that they would try and block the U.S. importations of the LNG into their home territory, where up until recent years they have been dominant and expected to be the dominant provider of natural gas for this century."

LNG exports represent a significant slice of the overall U.S. gas business by

U.S. LNG Exports by Month (MMcf)



Source: U.S. Energy Information Administration

now—and it promises to get bigger. In July, Cheniere Energy announced the first cargo from Train 2 of its new Corpus Christi, Texas, plant. The operation's Train 1 shipped its first LNG at yearend 2018. Train 3 is scheduled to start making cold in 2021.

Corpus Christi's three plants will have a capacity of 13.5 mtpa. Eventually, the plant could be enlarged to make 23 mtpa. That's a lot of gas—and just one of several plants under construction in the U.S. They will add to LNG coming out of Cheniere's Sabine Pass operation and Dominion's Cove Point, Md., plant on Chesapeake Bay that takes a big chunk of Marcellus and Utica gas production.

The ripple effect

But there could be a ripple effect in the oil and gas industry if LNG sales prices go—and stay—negative. Haas noted there's already a slowdown in the construction and start-up of new LNG capacity. Meanwhile, Wells Fargo noted third-quarter LNG tanker rates averaged $56,000/day. That's up from as low as $42,000/day in the first quarter but well below peaks around $75,000/day last year.

"There are a couple of things people are starting to wonder about, such as the potential for shut-ins," Haas said. "But I think prices would have to be significantly lower, maybe in the $1.50-1.60 per MMBtu range, for shut-ins to actually start happening, and I think that we'll stay above those prices.

"We could test the two-dollar range, though, like in the high $1.90-1.95, somewhere there," he added. "But the LNG business still has a significant volume of business tied to long-term deals, although that business model has been changing to something more akin to the comparatively fast moving crude oil market."

That could change "in the blink of an eye," he noted, "but that said, it's kind of a big transactional cost to renegotiate."

"I think, maybe, perhaps 80% of the flows are pretty much locked in on contracts," Haas said. "That extra 20% is typically held by the house, the owner of the LNG facility, and that's traded on their own account in the spot market. So that is really kind of what we think is at risk. And so, does that really hurt the gas story in the U.S.?"

Back to Alaska

The next chapter in the LNG story could open right back where we started: Nikiski, Alaska. A new terminus—a gigantic liquefaction plant, storage tanks and docks—could go up, right down the road from the mothballed Kenai plant.

The Alaska Gasline Development Corp. (AGDC), a joint venture of Alaskan producers and the state, envisions a three-train liquefaction plant that could cool and ship 20 mtpa of LNG.

If built, that plant would enjoy significant distance advantages to customers in China, South Korea and Japan over LNG coming from the U.S. Gulf Coast, Australia or the Mideast. Alaska lies just a week or so sailing time from those markets. Compare that to weeks, or maybe a month, of travel through the Panama Canal or across the Indian and Pacific Oceans.

Plus, the plant would be fed by trillions of cubic feet of proved gas reserves below ground on Alaska's North Slope.

Problem: The North Slope lies 800 miles away, as far as Houston is from St. Louis. It would take a lot of pipe to connect the two ends of the operation, and that makes the economics iffy at today's prices. Meanwhile, AGDC has moved ahead with the Federal Energy Regulatory Commission process. ■

Paul Hart *can be reached at* ***pdhart@hartenergy.com*** *or* ***713-260-6427.***

Source: Shutterstock/Pop Tika

Gas In Transition

How will the U.S. natural gas market change in the coming decades? There are two likely options.

Last year, the INGAA Foundation commissioned a thorough flagship study—"The Role of Natural Gas in the Transition to a Lower-Carbon Economy"—prepared by Black & Veatch Management Consulting LLC. The recently published review outlines what could happen to the natural gas market and what the industry—particularly the midstream—can do to prepare now for an uncertain future.

A 12-member steering committee, led by Don Santa, INGAA Foundation president and CEO, and Deepa Poduval, Black & Veatch associate vice president and oil and gas industry executive, coordinated the project. These are the study's key findings. Copies of the full report are available online at ingaa.org/foundation.aspx.—Paul Hart

The evolving role of natural gas continues to be at the forefront of U.S. energy industry developments.

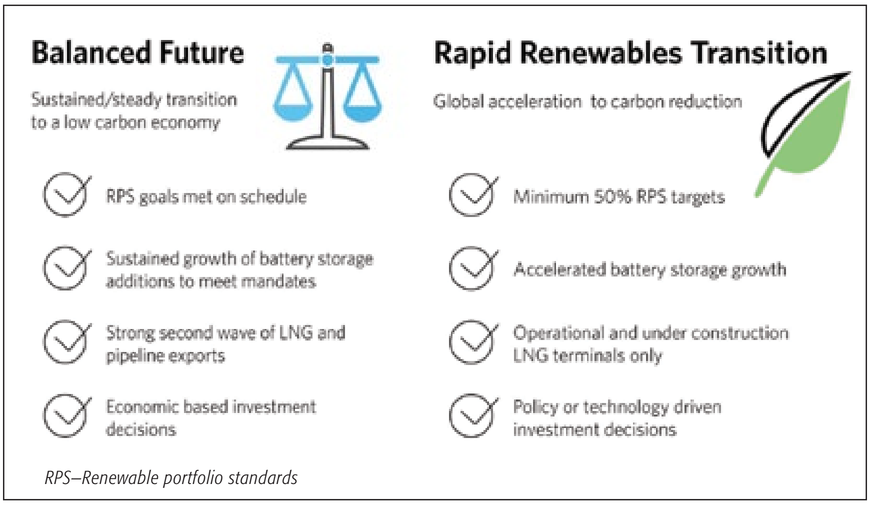
This evolution to a lower-carbon economy, including how growing renewable power generation and battery storage will affect gas-fired power generation—and the resulting effect on the utilization of midstream natural gas infrastructure—is an important consideration for natural gas midstream operators and the value chain supporting the construction and operation of midstream infrastructure.

This study on the role of natural gas in the transition to a lower-carbon economy was undertaken to examine trends affecting energy use in the United States over a 20-year horizon, from 2020 to 2040, with a focus on understanding how natural gas complements a lower-carbon economy while identifying potential challenges and opportunities for the natural gas pipeline industry.

This report presents a comprehensive strategic and analytical study to help educate key stakeholders, including energy consumers, infrastructure investors and policy makers, about how natural gas and natural gas infrastructure will be needed and utilized in a lower-carbon economy.

Breakthroughs

Over the last decade, spectacular breakthroughs in exploration and production technology have transformed the natural gas industry. Producers have dramatically reduced the time required



Source: INGAA Foundation

to drill and complete wells through increased efficiency in their multistage hydraulic fracture stimulations.

Increased use of data analytics continues to improve well completion designs and the ultimate recovery from each well. Shale gas production has grown almost 20% per year over the last 10 years. Low and stable gas prices have allowed natural gas to become the primary fuel for power generation. The combination of increased production and growing domestic markets created the need for new and reconfigured natural gas pipeline infrastructure.

Increasing global consumption of natural gas is also driving infrastructure needs in North America to serve newly-constructed and planned liquefied natural gas (LNG) export terminals along the U.S. Gulf and East coasts and pipeline expansions to deliver natural gas to Mexico.

Simultaneously, the impetus to reduce greenhouse gas (GHG) emissions has triggered state and regional mandates to reduce carbon emissions across all sectors. Some suggest that GHG emissions from natural gas combustion and distribution system methane leaks could be reduced by electrifying residential and commercial energy applications that historically have been met with natural gas.

Advances in solar and wind power generation technology, combined with the extension of the production and investment tax credits, have spurred significant renewable generation capacity additions over the past decade.

The study examines how these key drivers could affect the role of natural gas and the utilization of gas infrastructure over the next two decades. Our extensive analysis, supported by detailed modeling and industry subject matter expertise, centers around future scenarios that model different levels of renewable penetration and examine the effect on natural gas demand.

These scenarios focus on two possible paths toward an energy portfolio that relies increasingly on renewable energy:

- One path reflects a result driven by a balance of policy initiatives and market economics—a balanced future; and
- An alternative path is driven heavily by policy initiatives intended to accelerate the penetration of renewables in power generation—a rapid renewables transition.

Key findings are:

Natural gas will remain a significant contributor to the energy portfolio and economic growth in the United States.—Over the next 20 years, the current U.S. natural gas pipeline infrastructure will continue serving both traditional end-use sectors, namely those that are residential, commercial and industrial, as well as emerging sectors, such as pipeline exports to Mexico and LNG exports to the global market.

Rising gas demand and production levels could spur the need for up to 21 billion cubic feet per day of new gas pipeline infrastructure to support the shift in demand and supply driven by global LNG demand growth, booming pipeline exports to Mexico and continued demand growth from the petrochemical sector, or to enhance the reliability of the power generation sector.

Natural gas-fired power generation will continue to play a key role in meeting low-carbon initiatives. —The variability of renewable generation, especially solar and wind generation, will require flexible, fast-ramping generation or energy storage. Natural gas-fired generation will allow an increasing amount of renewable energy in the electric generation portfolio by providing electric grid reliability in the form of load and generation profile following, backup power, frequency regulation and spinning reserves.

Battery storage at scale will be able to provide some of these services; current battery technologies, however, do not support the full range of flexibility needed, including for seasonal and daily variations, and therefore cannot displace natural gas-fired generation, which is uniquely suited to mitigate this variability. Even assuming technological advancements, declining life-cycle costs and solutions for disposal issues, battery storage may become economically comparable to gas-fired generation only toward the end of the analysis period.

Therefore, regardless of any assumptions about increasing renewable generation, natural gas-fired generation will continue to play a crucial role in ensuring that peak electric demand is met reliably.

Demand for non-ratable flow interstate natural gas transmission services and hourly nominations will increase.— The continued evolution of the gas transmission industry to support a lower-carbon economy over the next two decades will alter shippers' requirements for natural gas pipeline services. Renewable integration will require quick-ramping, gas-fired generation during specific hours of the day.

Increased integration of intelligent metering will allow local distribution companies that serve traditional residential and commercial sectors to predict and respond to peak hourly need and to offer demand-response programs that can reduce overall design day needs.

If natural gas-fired generators are expected to serve as the backup when renewable generation is unavailable, these shippers may require pipeline services that allow them to nominate on the pipeline with little-to-no notice and grant them the ability to consume gas non-ratably. In such cases, pipelines must have the capacity to offer such services, and if they do not, pipelines must be sized to do so. In cases where existing capacity is insufficient to support such services, the shippers demanding such services must be willing to pay for the needed capacity.

Market uncertainty

Uncertainty about the energy future is nothing new for natural gas or any other energy source.

Market dynamics can change because of any number of factors, including a sudden technological breakthrough or federal or state energy policy decisions.

Over the next two decades, global market forces and regional U.S. policy initiatives may change the way we think about the role of natural gas. In the mid-2000s, the U.S. was positioning itself to import LNG from around the globe and perhaps pipeline gas from the Arctic, as domestic conventional natural gas supplies were steadily declining. This changed rapidly when the shale revolution made domestic natural gas abundant and affordable.

Today, we know that there is both a domestic and a global impetus for reducing carbon emissions and transitioning to a lower-carbon economy. Natural gas will play a key role in supporting this initiative by providing a safe, reliable and affordable source of energy.

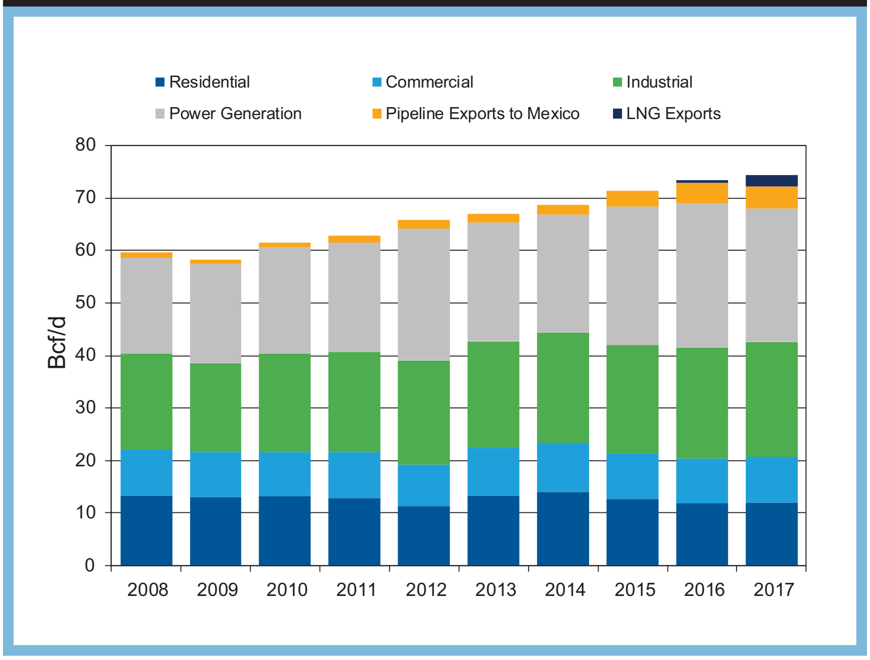
Opposition to gas

Natural gas transmission infrastructure is built to serve the economic needs of the market and is supported by shippers willing to commit to long-term firm transportation contracts to use the capacity. Despite the steadily increasing consumption of natural gas, opponents of natural gas infrastructure projects argue that increased renewable penetration will decrease the demand for natural gas-fired generation, thereby leaving gas transmission assets stranded.

Demand for gas transportation services from the power sector, however, has not been the primary driver for recently proposed pipeline projects.

Rather, other sectors have been the primary drivers of new pipeline infrastructure investments and utilize the majority of existing gas pipeline capacity. These shippers will continue to rely on natural gas and natural gas infrastructure, even as demand for renewable energy increases.

The Current Role Of Natural Gas



Source: INGAA Foundation

Natural gas usage trends in traditional end-use sectors (residential, commercial and industrial) and nontraditional sectors (LNG exports and pipeline exports to Mexico) will also significantly affect how the natural gas infrastructure will be utilized to meet the needs of all energy consumers in a safe and reliable manner. The INGAA Foundation is seeking to understand the future roles of natural gas and natural gas infrastructure in a lower-carbon economy for a 20-year analysis period, as well as the challenges and opportunities for the natural gas industry as it fulfills these roles.

Ramp up-ramp down

The continued development of renewable resources across the country, coupled with slower than expected electric load growth, has dampened the need for new baseload generation capacity. Concurrently, the need for dispatchable generation that can quickly ramp up and down has grown.

In California, for example, the continued addition of solar resources has significantly changed the typical daily net load profile, with a deep midday drop and steep ramp rates in later afternoon and early evening hours. In West Texas, the significant amount of wind capacity has frequently driven electricity prices into the negative during the off-peak hours. The duration and magnitude of this kind of shift across the country will affect the amount, timing and duration of demand for natural gas to support the power generation sector and how pipelines and storage facilities will be utilized to facilitate renewable energy growth.

Global and U.S. initiatives to create a lower carbon economy will also impact traditional and non-traditional demand sectors. North America's entrance into the global LNG market will provide Asian and European consumers with the benefits of competition that includes a low-cost supplier. U.S. LNG exports are expected to continue to grow over the analysis period and are expected to have a sustained impact on the need for natural gas infrastructure.

Conclusions

Across both scenarios examined, natural gas will continue to serve both traditional (residential, commercial and industrial) and emerging sectors (e.g., LNG exports and pipeline exports to Mexico) while playing a greater role in complementing renewable generation growth.

Gas-fired generators, with the help of pipeline and electric grid operators, have been able to ensure a stable and balanced electric grid. Higher levels of renewable generation over the next two decades will create new challenges in the electric transmission sector that the natural gas industry can help overcome.

> **The continued development of renewable resources across the country, coupled with slower than expected electric load growth, has dampened the need for new baseload generation capacity.**

Also, gas-fired generation will require additional flexible transmission services to balance the growth in renewable generation and support electric grid reliability.

LNG exports and pipeline exports to Mexico support the U.S. trade balance and work to reduce global emissions by replacing coal and other fossil fuels with clean-burning natural gas. With renewable generation growth in emerging markets, natural gas in the form of LNG will be needed to mitigate hourly and seasonal renewable variation.

In both scenarios, U.S. LNG export terminals will be utilized at high capacity factors because U.S. gas supplies will remain competitive with global LNG alternatives.

Existing and new natural gas infrastructure will continue to play a critical role in facilitating future natural gas consumption.

Across both scenarios, natural gas infrastructure allows reliable, low-cost gas supplies to be produced and transported to meet critical needs and to support the transition to a lower-carbon economy. ■

Working natural gas in storage volumes could be on the low side as a new heating season begins.
Source: Shutterstock/Zivica Kerkez

Bigger Market, Tougher Forecast

The global gas trade impacts domestic natural gas markets now more than ever.

By Frank Nieto

Natural gas has long been a global commodity, but until recently the U.S. was largely sheltered from this global market. Instead, the U.S. natural gas market was for the most part self-contained, aside from Canadian imports via pipeline and small amounts of liquefied natural gas (LNG) imports.

Domestic gas prices were primarily dependent on seasonal demand for heating and cooling. Most of the time, the easiest way to determine natural gas storage levels in the U.S. was to ask, "How's the weather?"

However, since the dramatic increase in domestic production of gas resulted in the U.S. exporting large quantities of LNG, the U.S. has entered the global market in a major way. It's gotten to the point that, while one of the key questions regarding gas storage levels still concerns the weather, now it isn't just about the weather in the U.S. but also in Europe and Asia.

"More and more we have to look at the global picture and what the weather might be like in Europe and Asia. It's becoming more important for the U.S. to focus on global markets," Terry Ciliske, principal at En*Vantage Inc., told *Midstream Business*.

As U.S. LNG exports continue to increase, that increases the number of drivers from around the world that impact domestic markets, including U.S. gas storage injections and withdrawals. This makes it more difficult to forecast natural gas storage levels, even on a short-term basis.

En*Vantage estimates that natural gas storage levels will be about 3.7 trillion cubic feet (Tcf) by the end of the summer. However, the more global nature of the U.S. gas market means it's more difficult to have a firm hold on natural gas storage predictions.

"My biggest concern over the next few months is what could occur data on some ships. "The way we run our numbers, we haven't seen a fall-off on net Chinese LNG imports."

Ciliske added that there are also concerns over the sustainability of the European LNG market.

"Storage capacity in Europe was at over 70% full in June, and based on the data I'm looking at going back a decade, we're not quite at record levels from a percentage standpoint—but we're close. If things continue to deteriorate, then it would not surprise me to see U.S. export levels start to come down. If that's the case, then you'll start to change the end-of-season storage levels fairly dramatically."

Record pace

From a domestic point of view, overall power generation demand was tempered this summer. According to the U.S. Energy Information Administration (EIA), the first four months of the storage injection season saw an average of 98 billion cubic feet (Bcf) of gas injections. The cumulative net injections were about 41% higher than the five-year average—and at a record pace.

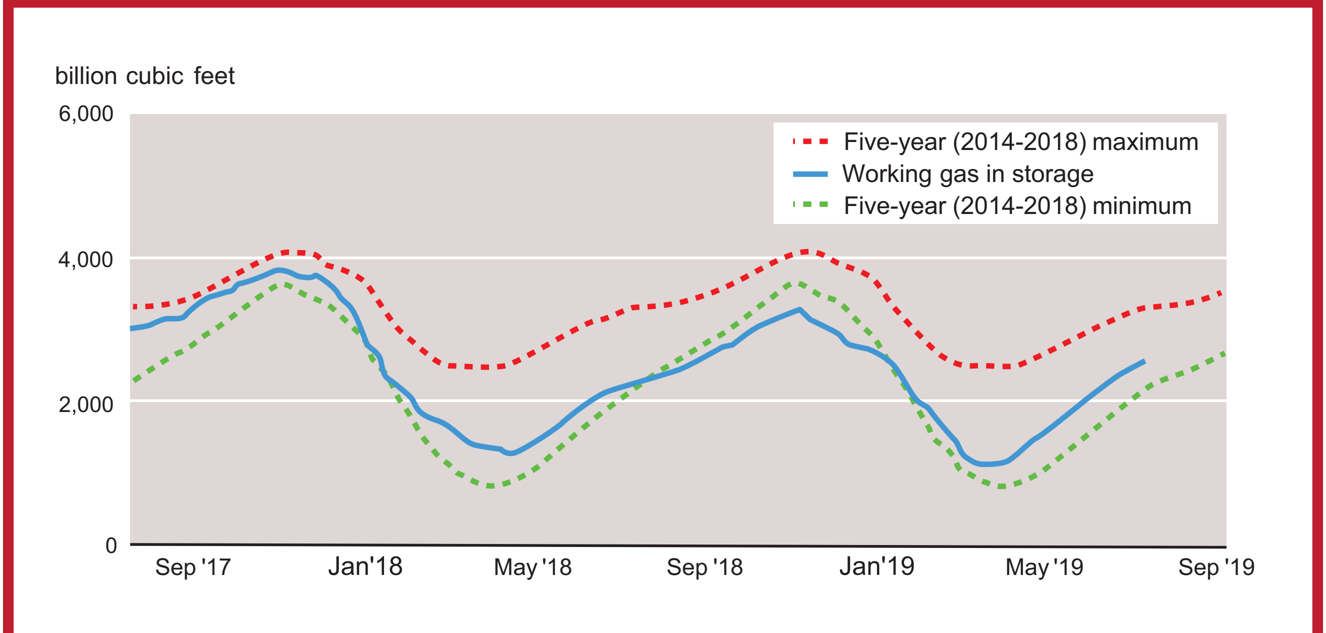
Part of this record pace involves the fact that there was an extremely low storage level coming out of the 2018-19 winter heating season, with only 1.137 Tcf of gas in storage, with working gas stocks 30% lower than the five-year average, according to the EIA.

"The 2018-19 heating season had the lowest level of working gas stocks in the United States for this time of year since 2014, when working gas stocks ended, the 2013-14 heating season at 837 Bcf because of multiple, intense cold snaps," the EIA said in a research note.

Despite the stagnant cooling demand that impacted gas markets at the start of the cooling season, U.S. natural gas demand is up due to increased power generation use.

"We have not seen the highs like we did last year. We've had a bunch of coal-fired power plant shutdowns and have added a lot of gas-fired power generation year-over-year. These are helping to absorb volumes, plus the low prices that we're seeing in the field are sufficiently low enough to pick up some incremental load in certain sectors of the country in place of coal. In areas like the Permian where gas is

Working Natural Gas In Storage



Source: U.S. Energy Information Administration

with LNG exports. The arb on LNG is continuing to get compressed, and prices in the Asian markets are more or less holding steady," Ciliske said.

He noted that while there have been some discussions about China backing off of LNG imports, En*Vantage believes that there is flawed tracking essentially free—and assuming there's sufficient transmission to local power plants—local generation is running pretty strongly, aside from holding back what they need for peak day reserves," Ciliske said.

An aspect that has been overlooked when it comes to peak cooling days is that gas will be consumed at a much higher rate than during non-peak days. This isn't just because there's increased demand, but because as you go up the power demand curve, more gas is consumed.

Typically, power generators will operate their newest and most-efficient units, but at peak demand they will use most of their capacity—including older power plants—to meet demand. These older units aren't as efficient as newer ones and may require up to twice as much gas on a burn cycle.

"If we get extremely hot temperatures, then price doesn't matter as much because utilities will run everything. In the middle of August with high temperatures, nothing is going to get shut down, so prices can rise and there's not as much demand elasticity for natural gas in the middle of August based on price. It's strictly a function of weather," he said.

"We have to replace about 2.5 Bcf/d every month so a lot of the drilling is going to replace the declines rather than growing the supply base. … We're running faster and faster to stay in place."

– **Terry Ciliske**, *principal, En*Vantage Inc.*

Permian capacity

The completion of several new pipeline projects could prove to be a wild card when it comes to gas storage levels this fall. Ciliske said that Kinder Morgan's new Gulf Coast Express Pipeline will transport up to 2 Bcf/d of natural gas from the Permian Basin to the Gulf Coast.

"There's gas that's available in the Permian that's not currently going to market, so we could see a pop in production as soon as that line starts filling. Flared gas or shut-in gas will seek its way outward, and that will result in the basis getting much tighter in the Permian," he said.

"What should happen is that if netbacks aren't atrocious, these volumes will make their way into this system. You'll then see a reduction of gas flow going north out of the Permian since they'll get better netbacks going east to the Gulf Coast," he said.

This has the potential to add another 50 to 100 Bcf of natural gas into storage inventories by driving the basis down in South Texas.

Good news/bad news

Pipeline exports to Mexico are a good news/bad news scenario for the U.S. gas market since there is a chance that these volumes could displace LNG that's currently making its way from the U.S. to Mexico.

According to Ciliske, Mexico isn't turning out to be the savior for the U.S. natural gas market that it was expected to be several years ago. While Mexican gas production is drastically decreasing and U.S. natural gas and LNG exports to Mexico have increased, demand for gas in Mexico isn't growing as much as it was expected to.

"Over the last five to seven years, we've seen U.S. natural gas export volumes to Mexico go from about 2 Bcf/d to about 5.5 Bcf/d. The perception is that demand is growing, but that's not right.

"Ninety percent of that load increase is because Mexico's natural gas production has been declining. Their demand has grown a little, but all we've done is increase our market share because their production declined. People tend to think that since we have this export capacity that demand will grow with it, and I'm not sure that's the case," he said.

Old drivers

While global factors have increased in importance, hot weather still plays an important part in determining how much gas will be in storage by the end of the summer. Not only do these high temperatures increase cooling demand, they also have an adverse effect on alternative energy—specifically wind-power generation.

"We have all of this wind power around the country, but the amount of output is very low in the peak of the summer because a lot of times when it gets hot, the wind dies down," Ciliske said.

He added that other forms of alternative energy struggle in hot weather. The most surprising of these is solar power, because solar panels produce substantially less power as temperatures increase. For example, if temperatures are between 100 to 105 degrees, solar panel power output could degrade by as much as 15%- to 20%.

Cooling demand may have been a bit slow to come on strong this summer, but the potential for a large overhang isn't quite as strong because of legacy declines in shale gas wells, Ciliske said.

"We've dropped off a little in drilling, but the amount of drilling that needs to occur just to maintain deliverability continues to rise, and we're now seeing the legacy declines in shales. We have to replace about 2.5 Bcf/d every month, so a lot of the drilling is going to replace the declines rather than growing the supply base. You're seeing the growth rate of crude and natural gas flattening out and slowing down. We're running faster and faster to stay in place," he said.

The well count

The overall drilled and uncompleted well count is about flat or even down a bit, yet the Permian Basin remains an area of growth for U.S. producers. There are still a lot of drilled and uncompleted (DUC) wells to bring online in the Permian Basin. The largest percentage of these wells are oil wells, which means they won't have as much of an impact on gas storage, but there will be some sort of impact as more gas wells in the region are completed.

Despite all of the changes in the gas industry, natural gas storage projects remain a hard sell. Ciliske noted that new gas storage projects haven't been attractive since about 2010. However, as renewables take a larger piece of the power market, they also add a lot of price volatility. This in turn increases volatility for gas supply and demand. This supply and demand volatility makes it pretty tough economically for storage facilities unless they're in key markets, such as the Northeast.

"The Northeast can be an attractive market for new storage facilities since operators are having so much trouble getting new pipelines built in the region. However, I think it's more likely that LNG will help supplement storage capacity, especially if the Jones Act is waived," he said.

The Jones Act requires U.S.-built vessels with U.S. crews to haul cargoes between domestic ports.

Even without the Jones Act being waived, LNG has served as a synthetic type of gas storage system, Ciliske said.

"We saw this last winter when prices spiked pretty steeply along the Eastern Seaboard and deliveries into the Cheniere LNG hub dropped way off. If producers have LNG sitting in tanks to fulfill orders they can reroute that gas into the U.S. marketplace instead, which dampens some of the volatility and puts pressure on storage values," he explained.

It may be harder to tell where storage levels are headed because of all of the changes in the marketplace, but one thing remains the same as the 2019-2020 heating season begins in just a few weeks: Storage levels remain a great mechanism for being able to see where gas prices could head unless stocks can either be replenished or storage overhangs can be quickly cleared. ■

__Frank Nieto__ is a freelance writer based in Washington, D.C., with more than a decade of experience covering the energy industry.

Canada's Search For Solutions

The Canadian oil and gas industry has entered a phase of re-evaluation and retrenchment. Pipelines are in the middle of it all.

By Jeffrey Share

Blame the vast political and geographical divide, blame an unclear regulatory climate, blame the U.S. shale revolution—which has reduced Canadian exports—blame the growing influence of the Indigenous people, blame environmental activism vs. development of the controversial oil sands, blame the inability to construct the final phases of the Keystone XL Pipeline (KXL) in the U.S., which would take that heavy oil to a ready and willing Gulf Coast market.

It all adds up to the same result: an energy industry with a loss of market share and capital investment.

Since 2016, only one major transmission pipeline application has been put forward in Canada, compared to 14 in the U.S. Bottlenecks have constrained producers seeking to move their product. The main beneficiaries of this pipeline drought are railroads, owners of storage facilities and U.S. producers.

One report said rail offtake from the Western Canadian Sedimentary Basin (WCSB) rose 40% in April over March, though not close to the record set last December. Analysts at Peters & Co. estimate that, until a new export pipeline is completed, the WCSB will need at least 400,000 barrels per day (bbl/d) of rail and/or curtailments to balance the market.

Maxed-out storage

Maximum storage capacity is estimated at 37 million barrels (MMbbl). Even with cuts made last fall by Alberta producers, oil inventories in Western Canada set a record of

Construction of Enbridge's C$5.3 billion Line 3 Replacement Program progresses between Alberta and Saskatchewan. *Source: Enbridge*

37.1 MMbbl in April, falling to 34 MMbbl in May, as reported by Genscape.

Hope arose in June after federal officials finally approved the long-awaited Trans Mountain Expansion Project (TMX), which will triple the amount of crude transported from the Edmonton region into British Columbia, ostensibly for export to Asia.

But it would have been far bigger news if the Trudeau administration had killed the C$7.4 billion project since his government bought its ownership from Kinder Morgan. (See accompanying article.)

In addition to TMX, the two other transmission pipeline projects are Enbridge's Line 3 Replacement Program and TC Energy's KXL. All three have been in progress for almost 10 years and are not forecast to be online for at least another two years. Construction on the Canadian portion of Line 3 is complete; however, the project is facing new delays in Minnesota.

KXL is in a holding pattern as well with legal challenges in Nebraska and Montana. KXL did receive a favorable appeals court ruling in Montana in late June, but TC Energy said it is too late for construction to start this year.

High cost of bottlenecks

In a study released in May, Toronto's Fraser Institute estimated that pipeline bottlenecks last year cost Canadian oil producers C$20.62 billion because of the huge discounts they were forced to offer. According to the Fraser Institute, if Canadian producers last year could have shipped volumes equal to their current levels of production, Western Canadian Select would have traded at an average of US$52.90/bbl instead of the actual average price of US$38.30/bbl.

Last year, Canadian heavy crude traded at an average discount of US$26.50/bbl compared to US$11.90/bbl less than West Texas Intermediate (WTI) five years earlier.

The Canadian think tank pointed out that in September 2018, Western Canadian oil production reached 4.3 million bbl/d, but the takeaway capacity remained constant at 3.9 million bbl/d.

For Canada's gross domestic product, the overall loss of oil revenue is about 1%.

Canadian producers and the Alberta provincial government agreed last fall to cut 8.7% of oil production, a scheme that has helped decrease the differential with WTI but is not seen as a long-term solution.

A new forecast released in June by the Canadian Association of Petroleum Producers (CAPP) was less than promising. CAPP estimated oil production will grow by an average of 1.4% annually until 2035, citing the lack of new pipelines and inefficient regulation for halving its more optimistic forecast on production growth, published just a scant five years ago.

Though Canada holds the world's third-largest crude reserves, CAPP insisted, "We need pipeline capacity and more efficient regulatory policy to help bring investment

> "Oil production from Canada could reach 4 million bbl/d from the current level of 3 million bbl/d. But timing on when that growth occurs is chiefly dependent on those three large pipeline projects and shifting investor sentiment on long lifecycle projects."
>
> – **Mark Oberstoetter**, *Calgary research director, Wood Mackenzie*

back to the oil sector and drive growth." CAPP also forecasts that capital investment in the industry will fall to C$37 billion (US $27.7 billion) in 2019, compared with C$81 billion in 2014.

Meeting challenges: C-69

Then there is C-69, the Impact Assessment Act that has sent an Arctic chill throughout the oil and gas industry. Following Canadian Senate approval in June by a 57-37 vote and already approved by the House of Commons, the bill quickly received royal assent to become law.

C-69 changes the review process by creating a new federal agency to assess industrial projects, such as pipelines, mines and inter-provincial highways, for their effects on public health, the environment and the economy. The Canadian Energy Regulator (CER) established by the Impact Assessment Agency (IAA) replaces both the National Energy Board and the Canadian Environment Assessment Agency.

Although the governing Senate Liberals accepted 99 proposed amendments, they rejected another 89 proposed by the Tory party that were sought by the energy industry. Alberta Premier Jason Kenney quickly labeled C-69 as the "No More Pipelines Law."

One reason the Trudeau administration gave for rejecting those proposed amendments was that they would have allowed the IAA to not have to consider the effects on Indigenous people or climate change when assessing a project. Other changes would have restricted limits as to who can participate in an assessment hearing, as well as making it more difficult to challenge a project approval in court, Global News reported.

Martin Olszynski, associate professor of environmental law and natural resources at the University of Calgary, told Global News that the newly enhanced consultation process might instead reduce some of the litigation brought against future projects because it would bring potential critics into the decision-making process before they get to the courts.

Industry representatives, however, have reacted with predictable fury to C-69's passage, insisting that it fails to create clarity and certainty necessary for future pipeline projects.

"We desperately need more investment," Chris Bloomer, president and CEO of the Canadian Energy Pipeline Association (CEPA), told *Midstream Business*, saying that working on C-69 has, and will continue to be, among the group's top priorities.

"Canada is sending mixed messages that will send critical investment elsewhere. Under C-69, our members have stated that it is unlikely that any new major pipeline project will be proposed, due to high financial risks associated with lengthy, costly project reviews. These are important projects, which inject billions of dollars into Canada's economy—money that would help pay for critical social services and the transition to a lower-carbon energy future," he said.

Lack of clarity

Bloomer said the industry is "gravely concerned" about the lack of clarity that has long surrounded Canada's regulatory processes.

"To be more competitive we need to reduce regulatory layering between jurisdictions. Earlier this year, CEPA commissioned a report on regulatory competitiveness. CEPA makes seven recommendations based on the report.

"Our oil and natural gas resources are landlocked, and because of that, foreign and domestic investors are either sitting idle or moving their money to more competitive jurisdictions. According to a report by the C.D. Howe Institute, planned investment in Canada's natural resource sector projects fell $100 billion between 2017 and 2018. This staggering drop is equivalent to 4.5% of Canada's gross domestic product," Bloomer said.

"The real impact is the fact that a lot of capital has been reallocated in the industry to other parts of the world, including the U.S. We've seen the departure of some major players. It's been very challenging and fast-moving. We're still in an area where it's a big concern," he said.

Bloomer acknowledged that the future of energy development in Canada and worldwide is a highly divisive subject. He said CEPA's research indicates that approximately one-third of Canadians are against pipelines; the other two-thirds are either supportive or neutral.

"It's important to note that Canada is a world leader in the areas of producing and transporting oil and gas. The average emissions intensity of oil extraction has fallen 21% since 2009, with strong potential for further reductions in the next decade. Canada's industry will reduce methane emissions by 45% from oil and natural gas operations by 2025," said Bloomer, adding that he and CEPA members "look toward the future with cautious optimism."

Work on Line 3 began at Hardisty, Alberta, and will continue to Superior, Wis. *Source: Enbridge*

Positive long-term outlook

Analyst Mark Oberstoetter, research director in the Calgary office of Wood Mackenzie, said he maintains a positive long-term outlook for Canadian's energy industry despite "significant egress challenges in the short term.

"The oil sands are ready to grow again with multiple steam-assisted gravity drainage projects ready for sanctioning and with improved economics breaking even below US$60/bbl WTI," he told *Midstream Business*. "But those sanctions will not occur until confidence in pipeline project construction improves. We see a positive path forward for all three major crude pipelines: Line 3 Replacement, KXL and TMX. But further delays remain possible which leave the upstream companies in further limbo.

"Oil production from Canada could reach 4 million bbl/d from the current level of 3 million bbl/d. But timing on when that growth occurs is chiefly dependent on those three large pipeline projects and shifting investor sentiment on long lifecycle projects."


The Burnaby Terminal outside Vancouver has been in service since 1953. It is the end point of the only North American crude pipeline to reach the Pacific. *Source: Kinder Morgan Canada*

Natural Gas

On the natural gas production side, he said, continued growth is driven by the Montney, one of the world's top five unconventional resource plays behind only the Permian, Eagle Ford and Marcellus.

"Growth would occur without LNG investment, but the increased demand coming from LNG Canada and Woodfibre help bolster our outlook for liquids-rich gas drilling in Canada's resource plays. We see the Montney growing to 20 billion cubic feet equivalent per day by 2030, led by many Canadian-based specialists alongside well-known companies like Shell, Petronas, Encana, ConocoPhillips and Murphy," Oberstoetter added.

The challenges

What are the biggest challenges energy developers face?

"Regulatory delays and legal roadblocks, public protests, changing political regimes, investor sentiment and cost management are all big issues in getting major projects built," he said.

"For upstream energy, an expansion to an oil sands project or drilling horizontal wells does not face all of these same challenges. Those companies are most challenged by the factors outside of their control: market access. They have to invest amid uncertainty over which pipelines get built, which determines market options and pricing."

Oberstoetter said TMX is critical for the Canadian industry, although local permits, further legal challenges and public protests could all cause delay.

"The pipeline is important emotively as an example of getting projects built. It would also offer market diversity away from the U.S. Other pipelines are equally

All Eyes Are On The Trans Mountain Expansion

The Government of Canada gave final approval in June for the C$7.4 billion Trans Mountain Expansion (TMX) project, subject to 156 conditions. First proposed in 2012, the project will triple the pipeline capacity from near Edmonton, Alberta, to Burnaby, British Columbia, near Vancouver.

The approval followed a federal court-ordered review of marine protection measures and more consultations with Indigenous people along the pipeline route.

Trans Mountain President and CEO Ian Anderson said construction should restart in September, pending no further delays.

"I think they're anxious to see us get started and anxious to get back to work," he said.

Construction will resume where it halted in August 2018. He said the project will eventually employ 5,000- to 6,000 workers.

Back at Burnaby

The work begins at Burnaby.

"It'll be back in Burnaby at our Westridge Marine Terminal, building out our dock, working in the Burnaby Terminal and recommencing work in the spread west of Edmonton and east of Jasper National Park. That's where we'll go back to work first. Then, over time as final permits and land acquisitions are made, we would work into the Edmonton area as well as the North Thompson area north of Kamloops as our next locations," he said.

Trans Mountain has operated a pipeline from Edmonton to Burnaby since 1953, bringing refined and unrefined products in a batch system into British Columbia and Washington State. Burnaby is home to two terminals—one houses 13 oil storage tanks and the other is the marine terminal, where fear of tanker spills has drawn opposition.

The pipeline has operated at its maximum capacity for many years. Producers primarily from the oil sands want additional space to ship more product and access world markets, specifically the Pacific Rim.

Trans Mountain decided a twinning of the existing pipeline was the best solution. The second line follows 73% of the original route and includes 610 miles of pipe with 12 new pumping stations, boosting capacity from 300,000 bbl/d to 890,000 bbl/d. Commercial agreements are in place with at least 13 shippers for 15- to 20-year contracts.

It is North America's only oil pipeline with access to the West Coast.

Government owned

Trans Mountain Pipeline is a wholly owned subsidiary of the Canadian Development Investment Corp. (CDEV), which is accountable to Parliament. Trans Mountain was owned by Kinder Morgan Canada, which sold the company to the federal government in 2018 because of increased opposition to the expansion, including a trade war between Alberta and British Columbia.

The plan is for outside investors, possibly including Indigenous communities, to buy into the project. Though not all Indigenous groups support the expansion, the *Vancouver Sun* reported that one influential organization hopes to acquire an equity stake.

"We always wanted equity, but in our negotiations with Kinder Morgan, equity was not on the table. When the Government of Canada bought the pipe, it opened the door to equity," said Michael LeBourdais, chair of the Western Indigenous Pipeline Group. He said ownership will give Indigenous people along the route the power to lead environmental risk assessments and "realize the largest economic benefits.

"This pipeline goes right through the middle of our reserve … so we are very familiar with where this pipeline goes and how it works. Most of us are firefighters, forestry workers and oil patch workers. We understand how safe it is. We can retain the expertise and the capacity to own and operate a chunk of this pipeline, and that's what we're going to do," LeBourdais said.

Wood Mackenzie analyst Mark Oberstoetter told *Midstream Business* that Indigenous participation is expected.

"While uncertain, we could see a government and Indigenous group partner during construction, and perhaps an industry group replace the government's share once built and de-risked. Private equity partners have shown high interest in other de-risked infrastructure projects."

—Jeffrey Share

important economically, especially as they offer routes to the high-demand U.S. Gulf Coast heavy crude market.

"If all three crude pipelines get built, we'd expect TMX to bring an extra benefit to light oil production, given access to markets in the U.S. Northwest and shipping to Brent-linked markets [not discounted WTI or Edmonton Mixed Sweet Blend].

"That said, the regulatory approval timeline and stability, knowing it won't change midway through, is a major factor for investors all over the world. I'd argue construction of the already approved projects is most important to get investor confidence back into upstream investments, but regulatory uncertainty will always loom if unaddressed," he added.

KXL is estimated to add ~$4- to $5/bbl in relative value for all Western Canadian crude grades. Meanwhile, TMX has the biggest impact for lighter barrels should all three proceed. Despite some recent setbacks (the Minnesota Court of Appeals overturned the approval of the Environmental Impact Statement), Line 3 has the clearest regulatory path forward to completion in 2021, he said.

> "Canada is sending mixed messages that will send critical investment elsewhere."
>
> – **Chris Bloomer**, *president and CEO, Canadian Energy Pipeline Association*

Ridley Island

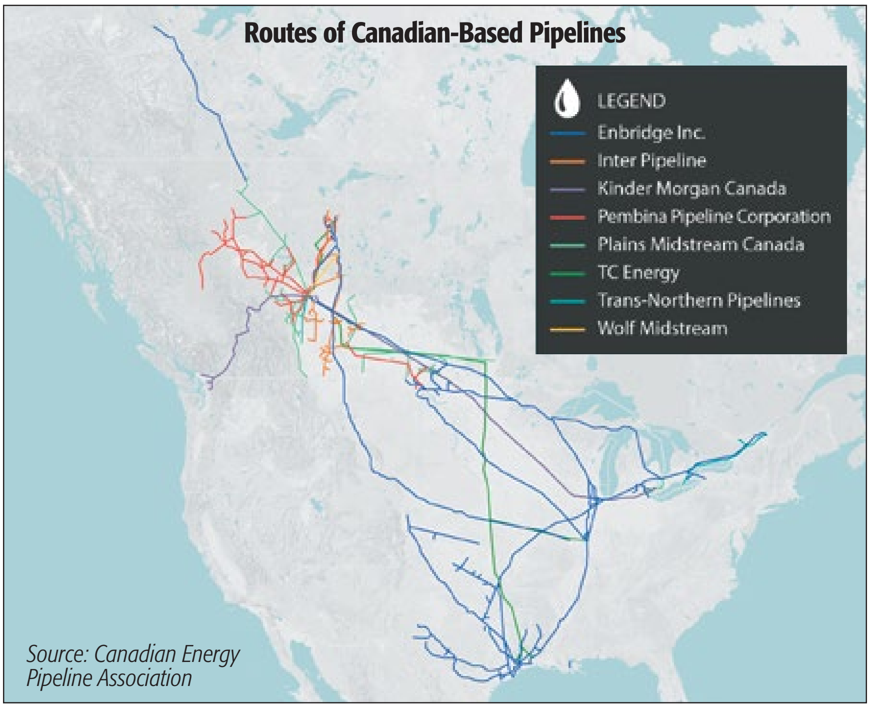
The successful construction of Altagas' Ridley Island Propane Export Terminal at Prince Rupert, British Columbia, this year will be positive for NGL prices. Pembina is also moving forward with an export project at Prince Rupert and a propane dehydrogenation plant in Alberta and shifting Alberta's production away from reliance on U.S. exports, the analyst said.

"On the gas side, LNG Canada is already moving ahead, and we expect Woodfibre LNG to make a final investment decision (FID) in 2019. Kitimat LNG, Jordan Cove and/or Goldboro LNG would all be additional upside but with longer term startups and not without their challenges."

LNG Canada has proposed a gas liquefaction operation at Kitimat. Woodfibre LNG is a proposed liquefaction operation north of Vancouver. Jordan Cove would be at Coos Bay, Oregon, drawing primarily on Canadian-produced gas. Goldboro LNG has been proposed in Nova Scotia on Canada's Atlantic coast.

"We do need continued investment in the processing plants; 2.2 Bcf/d is being built over the next three years in British Columbia and another 1.3 Bcf/d in Alberta, as well as regional pipeline buildouts: TC Energy's Upstream of James River capacity additions, North Montney Phase I and II, WEI T-South expansion, Coastal GasLink," Oberstoetter said.

In July, Plains Midstream Canada announced plans to expand its Rangeland crude oil pipeline to provide more capacity north to Edmonton and south to Carway on the Alberta-Montana border. Combined, the expansion will increase Rangeland's current light crude oil capacity to 200,000 bbl/d. The expansions will be staged into service later this year with full capacity in 2021. ■



Routes of Canadian-Based Pipelines

Source: Canadian Energy Pipeline Association

***Jeffrey Share** is a Houston-based Hart Energy contributing editor specializing in midstream energy topics.*

 BY PATRICK MCKONE, *WSP USA*

SPONSORED CONTENT

WSP USA Energy - Injection Well Expertise: Reducing Risk, Reducing Cost

Safe, approved deep well disposal of fluids are routine in industries such as food processing, specialty chemicals, oil and gas, refining and cavern development. So, it was a very strategic fit for WSP USA in 2012 (Parsons Brinckerhoff Energy Storage Surfaces at the time) to acquire the drilling specialty firm Subsurface. Since then, the expertise in this highly technical field has enabled WSP to zoom to the forefront in design, drilling, completing and maintaining these important assets.

When a client approaches WSP to drill a new injection well, the injection well team swings into action by compiling all of the information they can gather on the proposed new well. The injection fluid properties, maps, geologic data, drilling logs and other information provided by the client can then be processed into a work plan.

“No two wells are alike, so we work closely with each client to clearly define their specific requirements,” said Tim Jones, WSP injection well engineer. “We look for ways to design the well to address drilling risk and save on well cost.”

That philosophy was put into practice on new wells that were drilled and completed recently—one for a specialty chemical company and another for a refinery. The specialty chemical company’s new well was drilled near Port Lavaca, Texas using Energy Rig #12, a rig that was a perfect match for drilling the well to the required total vertical depth. The new well will be used to safely inject spent acid, which eliminates trucking and product handling.

“Our refining client is a long-standing WSP client dating back to the Subsurface days,” Jones said. “We already had a good idea of what they were looking for in the well design, so we had more time with them to discuss rig selection.”

After a thorough sourcing evaluation, Patriot Drilling Rig #4 was selected for the new drill, an Underground Injection Control (UIC) Class I non-hazardous waste disposal well, located in Artesia, New Mexico. Artesia is a city in Eddy County, which is home to the 100,000 barrel per day refinery. The Patriot Rig is large powerful rig capable of drilling deep injection wells—a perfect match for drilling in this region.

Following careful study of client requirements and the subsurface geology, the new UIC Class 1 well was designed as an open hole completion, at a formidable total vertical depth of almost 11,000 feet. The well design was based on a proven design to provide high injectivity with maximum injection interval access, ensuring the well will remain in service for a long time, which is just what the client needed.

WSP was contracted to install the well and installation began in March 2018. According to the well completion report, 20-inch conductor casing was augured to 80 feet below ground level. A 17 1/2-inch hole was drilled to a depth of 1,680 feet and 13 3/8-inch surface casing was set at 1,680 feet below ground level.

Energy Rig #12 on location in Port Lavaca, Texas. *Source: WSP USA*

Patriot Rig working in Artesia, New Mexico. *Source: WSP USA*

No two wells are alike, so we work closely with each client to clearly define their specific requirements

The casing was cemented to surface with good cement returns to surface. The casing was pressure tested according to New Mexico Oil Conservation Division (NM OCD) requirements.

A 12 1/4-inch diameter hole was drilled to 10,360 feet relative to the kelly bushing elevation (RKB), which is 20 feet above ground level; and 9 5/8-inch protection casing was installed from 10,327 feet RKB to the surface. The casing was cemented with 1,716 cubic feet (306 barrels) of Halliburton premium plus cement from total depth to 6,550 KB. The upper portion of the casing was cemented with 3,092 cubic feet (551 barrels) of Halliburton premium plus cement with good cement returns.

A Weatherford model AS 1-X packer was set in the 9 5/8-inch at 10,265 feet RKB and 10,265 feet of 7-inch, 26 pound per foot, K-55 LT&C was run in the wellbore. The casing annulus was filled with corrosion inhibited heavy brine water and was pressure tested according to NM OCD requirements.

A mechanical integrity test was successfully conducted according to regulatory requirements and consisted of an annulus pressure test and a radioactive tracer survey. NM OCD personnel elected not to witness the radioactive tracer survey. An injection pressure buildup and falloff test were conducted according to guidelines of the NM OCD for Class I nonhazardous waste injection wells.

"The basis for this new well is to efficiently dispose of utility blowdown water," Jones added.

WSP, with the acquisition of Subsurface, has drilled 45 Class I injection wells and Class II wells, over the last 30 years. For more information on WSP's Energy expertise, go to https://www.wsp.com/en-US/hubs/energy. ■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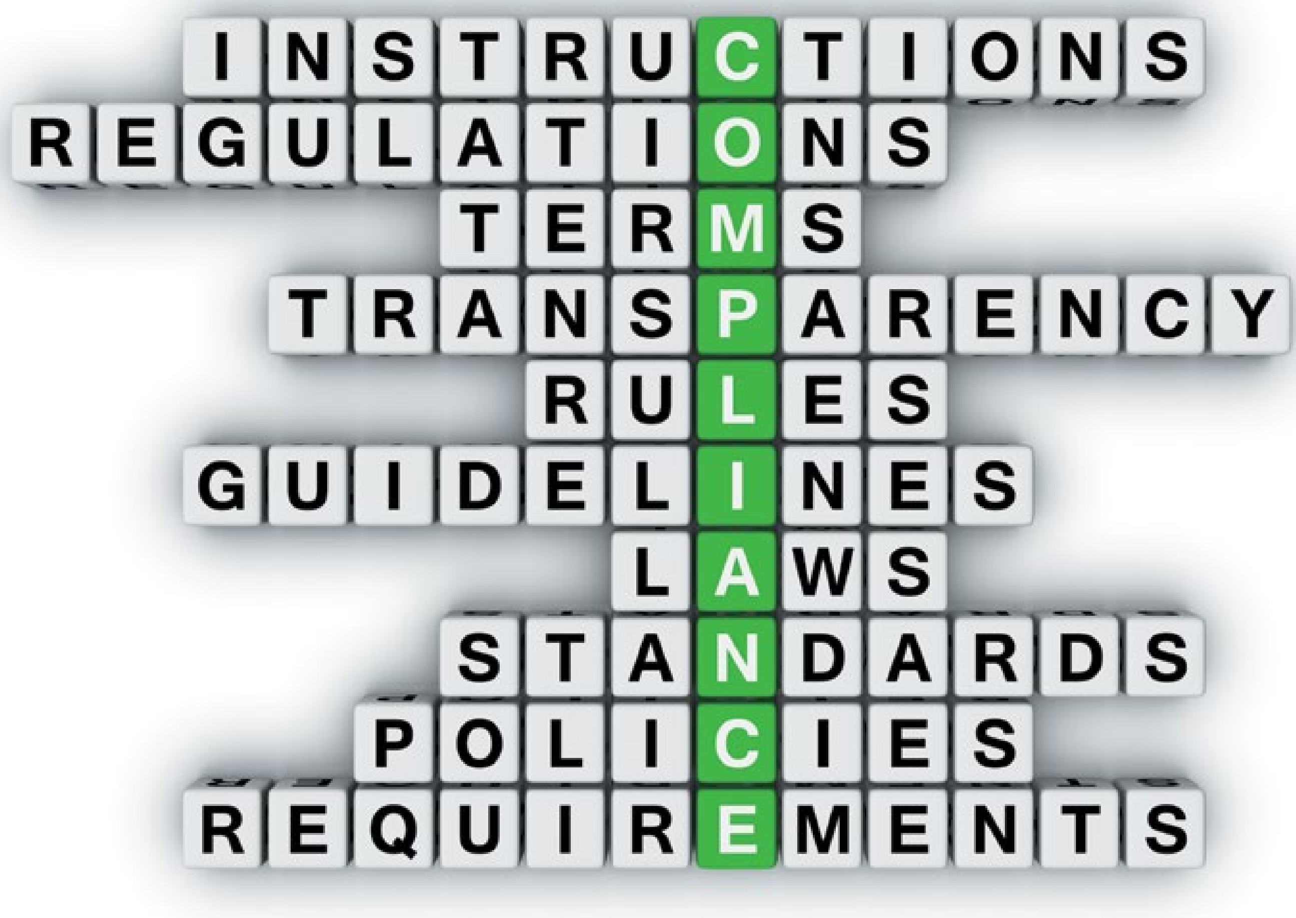

Source: Shutterstock/Almagami

Navigating the Permitting Process

There are key considerations for pipeline project developers seeking the necessary government approvals before construction.

By Emily Mallen and Jim Wedeking

Pipeline construction is no easy feat. Pipelines are highly engineered pieces of industrial property and subject to rigorous safety and environmental standards.

Commercial viability aside, the path from project conception to operation can take years with operators subject to a litany of regulations that must be addressed in order to enter service. Pipeline projects have never been without controversy, particularly from adjacent landowners with rights-of-way along their properties. However, it has only been in the last decade or so that individual pipeline projects became the subject of national debate, rallying support or opposition from persons living hundreds of miles away.

Now, it is common for a pipeline project to be the subject line of political fundraising emails as a way to galvanize support for a particular candidate or political party. This politicization can extend a project's construction timeline with extensive litigation over the propriety of its permits and authorizations.

Two ends

The politicization of infrastructure is not surprising, as communities that have not experienced greenfield pipeline construction in 50-plus years are confronted with the question of how to source their energy. On one end of the spectrum are communities excited to safely harness abundant domestic fuel sources. On the other end, environmental groups and local landowners wage a campaign against such sources' extraction and fossil fuels in general. These groups view pipelines not as transporters of a commodity that heats our homes and runs our businesses, but as a conduit for climate-changing greenhouse gas emissions.

Lawsuits now greet almost every planned interstate pipeline, and some state governments have vowed to block them altogether.

A friendlier federal government is not a project panacea, even with President Trump's promises to speed interstate pipeline approvals. The administration's élan, in the form of several Executive Orders, may exceed its practical abilities. Agency permitting decisions are ultimately constrained by statutes that can be changed only by Congress.

Moreover, there are decades of court rulings that outline project environmental reviews, which are unlikely to change, absent a Supreme Court decision. The result is a strange dichotomy.

Although pipeline companies may find allies in federal permitting agencies, such alliances may not guarantee a successful project. Permits and approvals may come more quickly, but they may be ephemeral victories if court challenges send the federal agencies—and pipeline construction schedules—back to the drawing board.

Challenged permits

Thus, a supportive agency decision rendered too soon or without adequate record support may work against pipeline developers if not handled properly. In the case of a challenged permit, it is the issuing agency, not the pipeline company, that controls the permit's defense. While the pipeline company can, and should, intervene in support of the agency, it is the agency's decisions, legal theories and factual record under review. And, each agency authorization provides an opportunity for a court challenge and project delay.

One recent example of a pipeline project delayed due to legal challenges to its underlying federal permits is the Mountain Valley Pipeline (MVP). MVP exemplifies the complex regulatory pathway a pipeline faces. Like every other interstate pipeline project, it requires a large number of authorizations to begin construction. As a natural gas pipeline, this includes a certificate of public convenience and necessity from the Federal Energy Regulatory Commission (FERC).

FERC conditions its certificates upon the pipeline obtaining all other necessary permits and authorizations. Hence, although FERC approved MVP's proposed route, MVP also requires a right-of-way and temporary use permit from the U.S. Bureau of Land Management because the route traverses 3.6 miles of the Jefferson National Forest in Virginia. Issuing these permits requires another agency, the U.S. Forest Service, to amend its Resource Management Plan, which sets out what can or cannot go on in the Jefferson National Forest. The route also necessitates the crossing of several rivers and streams in Virginia and West Virginia.

When it comes to pipeline litigation, developers must understand that every project is the opposition's next test case. Opponents will take what worked in the past and replicate it or take what did not and tweak it.

Another federal agency, the U.S. Army Corps of Engineers, must authorize these crossings.

Importantly, legal challenges to MVP's FERC certificate failed, and FERC overcame allegations that it did not sufficiently consider the project's environmental impacts. However, the other permitting agencies have not fared as well.

A federal court vacated the Bureau of Land Management's and Forest Service's permitting decisions. The court determined that the law required the Bureau of Land Management to study potential alternative pipeline routes through the Jefferson National Forest, such as a route that could follow an existing right-of-way. Because it did not do this, the court threw out the right-of-way grant and temporary use permit.

As for the Forest Service, the court noted the agency's critical statements concerning the pipeline's construction plans and potential impacts to soil erosion, which it had made during the Obama administration. The court faulted the agency, under President Trump, for failing to explain how its prior concerns were resolved. It also rejected the Forest Service's theory of why the pipeline was exempt from regulations requiring a separate environmental analysis on the pipeline's impacts to soil and riparian areas.

River crossings

Separately, environmental groups challenged the Corps of Engineers' authorization allowing MVP to use Nationwide Permit 12, a general permit, in West Virginia. The permit required MVP to observe certain West Virginia regulations for stream crossings. When environmental groups pointed out that the pipeline could not cross four major rivers within 72 hours, as West Virginia regulations required, the Corps deleted that condition from the permit. Environmental groups sued, and a court easily found that the Corps could not allow MVP to ignore valid state regulations.

None of these court decisions will necessarily prevent MVP from ultimately achieving final construction and operation. However, each involves federal agency decisions reversed or remanded due to a "paperwork" violation that presumably could have been avoided had the agencies provided more detailed explanations.

For example, the court suggests that the Forest Service would have prevailed had it better explained why the pipeline's existing erosion control measures were


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adequate and had the agency performed some additional environmental analysis. Presumably, this could have been accomplished with a few additional weeks of work and a few pages of text. Similarly, the court may have upheld the Bureau of Land Management's decision had it spent more time considering some alternative routes and better explained the reasoning behind its decision.

While the deficiencies can be cured, the months lost litigating these issues cannot be regained, and pipeline completion is delayed.

Even the Corps, which arguably faced the most serious problem of the agencies, may have avoided a court loss by taking additional time prior to issuing its permit. After the court's decision, West Virginia promptly changed its regulations to allow more than 72 hours for major stream crossings if the pipeline uses certain construction methods. Had the Corps worked with West Virginia *before* authorizing the nationwide permit, those stream crossings may have been completed by now. Instead, the agency now must respond to the court's decision and likely will be back in court when environmental groups inevitably challenge any new determinations.

Quarterbacking?

These analyses are not Monday morning quarterbacking of a pipeline project that diligently pursued every authorization it required to proceed. Nor are they criticisms of the agencies' arguments before the court. Rather, they highlight the agencies' incentives. While it is appropriate for executive agencies to respond, to varying degrees, to a President's goals of faster project permitting, pleasing a particular politician or constituency is not the end goal. Instead, the agencies' arguments are meant to preserve their own authority to exercise discretion.

Rather than add additional pages of analysis, the Forest Service chose to dispute the meaning of "directly related," a term used in one of its regulations. Guarding the Forest Service's right to decide which environmental standards are "directly related" to a Resource Management Plan is more important to the Forest Service than any pipeline project. This also may be why the Bureau of Land Management disputed the meaning of "to the extent practical," an ill-defined standard governing when the agency must analyze alternative pipeline routes, and the Corps claimed that it could override state law conditions.

In each case, the agencies asserted that courts should defer to the agencies' will—a priority as old as the administrative state itself and devoutly protected by all federal agencies regardless of who is president.

For a pipeline company, an agency's decision to avoid weeks, or even months, of additional permitting analysis as part of its exercise of discretion is not necessarily a welcome one if it will leave a permit more exposed to challenges. A pipeline may want to do more to bolster its permits. FERC's environmental reviews about pipeline greenhouse gas emissions provide one example of how a pipeline company can protect itself.

Currently, a slim majority of FERC commissioners insist that additional analyses of upstream emissions (from hydraulic fracturing) and downstream emissions (from the sources that combust it) are too speculative to be necessary. Recent legal guidance from the Trump administration supports this viewpoint as does some legal precedent.

However, environmental groups have repeatedly challenged this policy and will continue to do so. And, two recent court decisions strongly hint that FERC must dive deeper, making it perilous for a pipeline company to rely on FERC's existing policy.

A pipeline may be better served to develop upstream and downstream emissions data, insert it into the record, and work with FERC to explain why that data can be considered without undermining its overall policy. Otherwise, the company risks project delay if the court vacates the agency decision for failure to perform the analyses.

Data is also a project's best offense when the pipeline is the litigant. It can be used to undermine an implacable agency that slow-walks a project.

When it comes to pipeline litigation, developers must understand that every project is the opposition's next test case. Opponents will take what worked in the past and replicate it or take what did not and tweak it.

The underlying thread in much of the pipeline litigation is whether the agency had sufficient information to support its decision. A project's best defense in litigation, therefore, is good data and a willingness to share it with the public and the permitting agency to bolster its decision-making. This can include conducting studies that the agency is resisting and providing additional factual material for the administrative record.

Data is also a project's best offense when the pipeline is the litigant. It can be used to undermine an implacable agency that slow-walks a project.

With data, the right balance must be struck. Pipeline opponents will always demand more information and study as a delay tactic to sink a project.

However, good legal counsel can advise the company on which demands are merely make-work and which may be necessary under the applicable laws. More importantly, good counsel can push back against an agency willing to take risks with somebody else's multimillion-dollar project in order to press institutional prerogatives. ■

***Emily P. Mallen** and **Jim Wedeking** are lawyers in the Washington, D.C., office of Sidley Austin LLP. Mallen counsels natural gas and oil pipeline clients on regulatory and other matters, and Wedeking represents energy companies and other clients in environmental lawsuits.*

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W. H. Abrams #1: the first commercial discovery of oil in the Permian was in Mitchell County, Texas. It began production in June, 1920 with 20 barrels per day, and marked the opening of Westbrook Field.

— Source: The Petroleum Museum, and Midland Reporter-Telegram, June 2009

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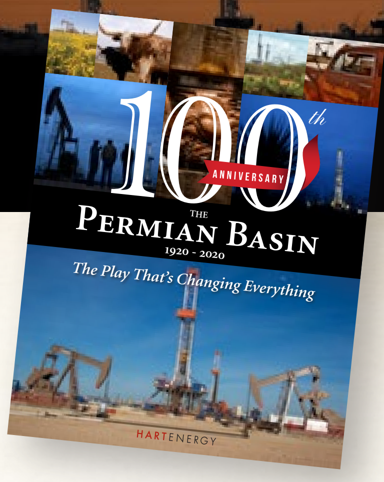

2020

January 2020

Hart Energy publishes a Centennial special issue to celebrate The Permian Basin's 100th Anniversary.

Featured Chapters:

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U.S. President Donald Trump, **Secretary of Energy** Rick Perry, **Texas Governor** Greg Abbott, **New Mexico Governor** Michelle Lujan Grisham, former **Secretary of Commerce** and **Permian Strategic Partnership Chairman** Donald Evans, former **President** George W. Bush, **Midland Mayor** Jerry Morales and **Odessa Mayor** David Turner (*Requested)

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Chapter 4 – Will To Succeed

The giants of the Permian Basin are those individuals who persevered through adversity, who disrupted tradition with new ideas, and who pioneered many innovations that have changed the worldwide industry.

Chapter 5 – Serving Up Technology

Operators and service providers are working together to rapidly evolve new and ever more effective technologies that aid in the discovery, production and transportation of Permian Basin oil and gas.

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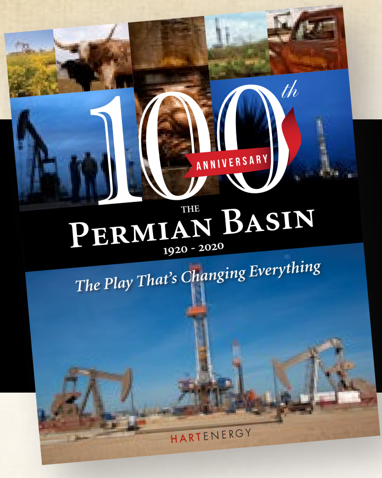
Local lenders, friends and families often provided the seed money for early Permian Basin explorers. Now Wall Street and private equity are all-in on this amazing play.

Chapter 8 – The Future

The future is bright for economic development and job growth across the Permian Basin communities. The industry is working hard on workforce development and community projects, and Texas and New Mexico will unequivocally lead the way in America's energy independence story for decades to come.



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Autumn comes early in the far north. The Trans-Alaska Pipeline weaves its way toward Pump Station No. 4 in the Brooks Range, some 200 miles south of the system's starting point near Prudhoe Bay, Alaska. *Source: Alyeska Pipeline Service Co.*

An Alaskan Oil Renaissance?

Increased North Slope drilling and production could further boost U.S. export volumes.

By Sandy Fielden

Alaskan crude production declined from a peak of over 2 million barrels per day (MMbbl/d) in the late 1980s to an average of 500,000 bbl/d in 2018, according to the Alaska Department of Revenue. Higher prices for this medium-sour crude now offer producers an incentive to expand output and exploit export potential to Asia.

That's good news, over and above prospects for an Alaskan natural gas pipeline and liquefaction project.

Refineries in Washington State and California consume most Alaska North Slope (ANS) crude. Recent limits placed on Bakken crude sent by rail to Washington State restrict any growth in refinery use of competitive shale grades—potentially widening the domestic market for ANS.

After most U.S. crude exports were banned in the 1970s to preserve dwindling national supplies, Alaskan crude was exempted from that rule during the 1980s. A further requirement—that the state's most prolific ANS grade be shipped to market using expensive, U.S.-flag Jones Act tankers—priced Alaskan crude out of world markets.

Asian markets

When the export ban was lifted comprehensively at the end of December 2015—including the Jones Act restriction—ANS (a medium-sour crude with an API gravity of 31.5 and 0.96 % sulfur) became an obvious candidate for overseas sales. That's because of its remote production location far away from U.S. refining markets and its relative proximity to Asian refineries. Many refineries in China, Japan and South Korea typically process medium sour grades from Russia and the Middle East that are similar to ANS, which can be delivered to Asia from Alaska in half the four-week journey time from the Arabian Gulf.

Since then, lower Alaskan production has restricted supplies to feeding regional refineries in Alaska, California, Washington State and Hawaii.

Unlike the U.S. Gulf Coast where surplus shale crude depressed domestic prices to attract overseas buyers, the lack of new ANS production has kept prices higher and closed the export arbitrage window.

Improving prospects

Today, there are better prospects for reversing the ongoing decline in Alaskan production. New discoveries and the recent application of more efficient technologies in the Prudhoe Bay, Alaska, region where ANS is produced led IHS Markit to forecast in August 2018 that output could grow by 40% in the next eight years to 2026.

Increased investment by legacy producers ConocoPhillips, BP and ExxonMobil, as well as newer discoveries operated by Repsol, ENI, Hilcorp and the Australian company Oil Search, have all shown promise for future output. Note that these expansions underway do not involve the Arctic National Wildlife Refuge or the offshore Arctic Ocean regions that were opened when the Trump administration overruled Obama-era restrictions in 2017. In the second quarter of this year, the administration appeared to roll back that ruling until after the 2020 election in response to public opposition to expanded drilling.

Since the new discoveries and drilling described above are happening outside of these environmentally disputed areas, they will not be impacted.

Since the shale era, any plans to expand ANS output have been overshadowed by the rapid growth in production in Texas and North Dakota, both of which require lower investment and are closer to U.S. refineries. However, the attraction of ANS-quality crude to both West Coast and Asian refiners helps justify new investment today, at a time when the world is arguably oversupplied with light shale crude.

Although Alaskan drilling costs are high, producers can leverage existing infrastructure, such as the 2.1 MMbbl/d Trans-Alaska Pipeline System (TAPS) that carries crude 800 miles south from Prudhoe Bay to the ice-free deepwater Valdez oil terminal, from where it can be shipped to U.S. or overseas destinations.

Similar cost savings achieved by linking to existing infrastructure have recently increased investment in offshore Gulf of Mexico drilling, where typical crude quality is also medium sour.

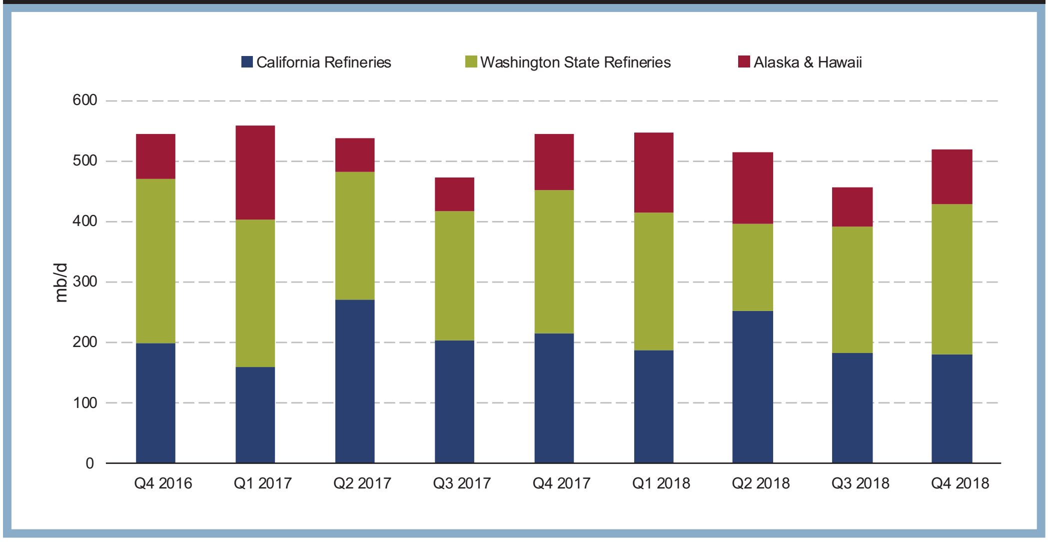
TAPS room

With current Alaskan output not much over 500,000 bbl/d, there's plenty of room on the TAPS pipeline for a 40% increase to around 700,000 bbl/d. At that level, ANS production would begin to exceed regional domestic demand—and encourage export flows.

Now, however, lower output and a lack of ready alternatives for regional refiners have raised ANS prices relative to both domestic and international grades. ANS prices earlier in 2019 averaged a premium of more than $9/bbl above the domestic benchmark West Texas Intermediate at the Cushing, Okla., trading hub, nearly 50 cents/bbl above international benchmark Brent and

Port workboats set booms around tankers during loading at the Valdez, Alaska, pipeline terminal as a precaution in case of a spill. *Source: Alyeska Pipeline Service Co.*

Alaska North Slope Refinery Demand



Sources: Morningstar, state agencies

65 cents/bbl above Mideast equivalent Oman crude.

ANS prices need to retreat below Oman to compete in Asian export markets.

Current demand

Current ANS production is either consumed by Alaskan refineries or shipped from Valdez on Jones Act tankers to Washington State and California, with a smaller volume going to Hawaii and exports confined to occasional spot cargoes, two in 2018, for example.

The accompanying chart shows our estimate of where ANS was consumed between the final quarter of 2016 and the fourth quarter of 2018. Volumes shipped to California, in blue, are from California Energy Commission reports. Volumes into Washington State, in green, are calculated from that state's Department of Ecology crude movement reports. The balance, in red, is quarterly production, minus California and Washington volumes, that we assume is mostly consumed in Alaska.

During 2018, the averages worked out to be 200,000 bbl/d to California, 208,000 bbl/d to Washington State and 108,000 bbl/d to Alaska.

Export prospects

With current supply and demand for ANS tight, prospects for exports depend on increased production exceeding regional refinery requirements. Important variables in that equation include the impact of competing crude supplies from Canada and North Dakota delivered to Washington State refineries.

On average during 2018, North Dakota Bakken represented 17% and Canadian crude delivered by pipeline 20% of Washington feedstock, with most of the rest being ANS.

Two potential changes to Washington State refinery supply could affect ANS demand. The first is completion from the Trans Mountain Express pipeline expansion between Edmonton, Alberta, and Vancouver, British Columbia, that would increase Canadian crude supply to the West Coast by 600,000 bbl/d. This much-delayed project, now owned by the Canadian government, may not be complete until after 2021, but it would allow Washington refiners to increase Canadian crude runs at the expense of ANS.

Increased Canadian supplies at Vancouver could also be shipped down the West Coast to California with the same impact—freeing up more ANS for potential export.

The second change impacts the volume of Bakken crude railed from North Dakota to Washington State refineries. These shipments, which averaged 148,000 bbl/d during 2018, could be curtailed or limited by a Washington State regulation concerning the quality of crude permitted to move by rail.

That regulation restricts crude flammability by imposing a Reid Vapor Pressure (RVP) limit of 9 pounds/square-inch on crude. That reduces crude volatility in case of a rail accident—but is regarded as prohibitively expensive by Bakken producers since it requires pre-processing crude to remove light components.

The implication is that a ban on crude over 9 RVP would preclude shipments to Washington refineries, rendering them increasingly reliant on ANS supplies. The final iteration of the legislation only applies to incremental crude barrels, representing 10% more than previously shipped by rail.

That would reduce the impact on current ANS demand.

Time is right

Whatever happens with Bakken crude-by-rail or Canadian crude supplies, the potential for increased ANS exports relies firmly on production shifting to a higher gear in the next several years. Right now, the relative shortage of sour crude in world markets caused by OPEC production cuts and sanctions on Venezuela and Iran easily justify increased output of medium sour grades like ANS, which is pricing higher than Brent.

Producers are making that bet by investing and drilling to increase output—hoping to leverage existing infrastructure to keep costs down. If the forecasted increase in production happens, there should be a market for more ANS—either at West Coast refineries or in Asian markets. ■

__Sandy Fielden__ is director of research, commodities and energy at Morningstar Inc.

Leak Detection

Too often, tragedy has to occur before industry and government personnel respond to hazards.

By Jeffrey Share

This cenotaph in New London, Texas, honors the 300-plus students and teachers killed in the 1937 explosion that leveled the town's practically new school. *Source: Shutterstock/Lori Martin*

Since moving to Houston 35 years ago, I've developed a historical—some might call it morbid —curiosity coming from living within the virtual epicenter of three of America's worst catastrophes.

First, there was the epic hurricane of 1900 that destroyed Galveston and left more than 6,000 dead. It remains by far the nation's deadliest hurricane.

Second was the 1937 New London school explosion in East Texas in which over 300 students and teachers were killed, hundreds more injured, in the nation's worst school disaster.

Third came the 1947 Texas City disaster in which ammonia nitrate, which was used as an explosive in World War II and now found useful as a fertilizer, was improperly stored aboard a French cargo ship. A lit cigarette carelessly tossed aside by a crewman found its way into the ship's hold. The ensuing blast killed more than 580 people and left thousands injured. It is the nation's worst industrial disaster.

Unfortunate coincidence?

These disasters were the results of a series of events all leading up to horrendous catastrophes. Was it an unfortunate coincidence that they occurred in a state that has never been known for strict regulations? That's for history to decide. Plenty of books have been written about each possible answer.

This article focuses on the New London school explosion, which was caused by a natural gas leak and led to sweeping changes in the energy business that I wrote about on the 75th anniversary of the blast. Recently, I received a copy of *Living Lessons From The New London Explosion*, written in 1938 by a local pastor, Rev. R.L. Jackson, and reprinted by the New London Museum. The 92-page book offered some information that further clarified what led to the disaster and its aftermath.

The New London school was in the center of the fabled East Texas oilfield. The community was prosperous enough to spend $1 million ($18.5 million nowadays) on the construction of the state-of-the-art building in 1932 and its expansion in 1934, with 737 students enrolled. It was the first school in the state to have electric lights on its football field. But one problem existed: constructing the school on sloping ground with a large enclosed air space beneath the building that stretched along the entire 253-foot façade.

The school board overrode the original architectural plan for a boiler and steam distribution system. Instead, they decided to install 72 gas heaters throughout the building. Then, they decided they could save on

Before and after photos of the New London, Texas, school. *Source: The New London Museum*

the $250 a month they were paying to the local gas company by rigging a device to a pipeline that was carrying Parade Gasoline Co. residual gas that would otherwise be burned off.

Illegal taps

It was a common ploy for homeowners and businesses to illegally tap into pipes carrying waste gas, with no thought given to the volatility and instability of the odorless, colorless gas. Refiners were later blamed for failing to enforce policies barring gas line taps.

The New London school's gas pipes were often jostled by students and teachers. The sub-basement was also very poorly vented. At the time of the explosion, Walter Cronkite was a 20-year-old cub reporter for a wire service and drove in from Houston on his first major assignment. He reported that the architect had reinforced the building with vertical rows of tiles. Gas was leaking from the residual line tap and had built up within the 15,000-square-foot sub-basement, soon filling the vertical columns of tiles.

"The school was a bomb waiting to explode, two minutes before school was to be dismissed for the weekend," Cronkite wrote. One report later said that students had been complaining of headaches but received little attention.

Jackson wrote that the explosion occurred when a teacher in the woodshop located adjacent to the sub-basement plugged an electric sander into a portable connection. A door to the gas-filled sub-basement was partially open, and some of the gas seeping into the shop was ignited by an arc formed when the two prongs of the portable switch touched the socket before it was driven into place.

The walls bulged and the roof lifted from the building as the main wing of the school collapsed. The death toll might have been even worse had it not been for roughnecks from the nearby oil fields who rushed to the scene with cutting tools, special lights and heavy equipment needed to dig through the wreckage.

Mercaptan

In the aftermath, the Texas Legislature passed the first law requiring the addition of a malodorant, Mercaptan, to natural gas to give early warning of a leak. Another new law required that anyone working with gas connections be trained and certified as an engineer by the state.

Heath Consultants Inc. has been a world leader in gas leak detection since the Houston-based company was founded in 1933. Paul D. Wehnert is senior vice president for sales and marketing. He's been with Heath for over 30 years and graduated from the State University of New York at Syracuse with a degree in environmental science. He is a frequent speaker on gas leak detection, so I asked him how that business has evolved since New London.

Wehnert said the majority of gas leaks occur in this manner:

- Cast iron—bell joints/graphitization;
- Bare steel—corrosion;
- Plastic—poor fusion joints/electrofusion fittings;
- Cathodic-protected steel—welds, coating flaws;
- Clamps, fittings, dresser couplings, etc.;
- All pipe experiencing third-party damage; and
- Environmental acts—hurricanes, earthquakes, flooding, etc.

He said that, prior to 1937, gas leak detection generally relied on visual vegetation surveys looking for dead vegetation caused by venting leaks from both natural gas and manufactured gas (coal gasification). Federal regulations were minimal until Congress passed the Natural Gas Pipeline Safety Act of 1968. Leak detection is a requirement under the DOT Federal 192 regulations based on pipe location and material. All natural gas companies must respond to public/customers' leak and odor calls with appropriate leak detection technologies.

"The immediate impact of New London was not allowing the public to take natural gas from producers directly for consumption without being adequately odorized. All odorant is added to natural gas for the public so in the event of a leak they have early warning. The gas in New London was supplied direct from the wellhead and not odorized. Thus, when the leak developed, the public didn't know," Wehnert told *Midstream Business*.

Detection techniques

Flame-ionization detectors became one of the early tools used to find gas leaks. They have since been replaced by optical infrared and laser-based technologies, he said.

> **"I did nothing in my studies or in my life to prepare for a story of the magnitude of the New London tragedy, nor has any story since that awful day equaled it."**
>
> — ***Walter Cronkite***

So, with natural gas becoming more prevalent, is the job of detecting leaks getting more difficult?

"Local distribution companies are highly regulated with respect to mandated leak detection," Wehnert answered. "Transmission companies are required to do mandated inspections on Class 3 and Class 4 locations. Wellhead—gathering—gas processing locations are not as regulated, and this is where more requirements will be forthcoming, both DOT-regulated and environmental, EPA."

Some of the new innovations being used to help detect leaks include fixed deployment of methane sensors in high-consequence areas, aerial surveys using fixed wing aircraft, helicopters and drones. More sensitive Advanced Mobile Technology devices are also being mounted in vehicles, he said.

What's Heath's strategy in maintaining its edge as an industry leader?

"We continue to listen to our customers and follow regulatory requirements to keep ahead of the technology curve. We are seeing an even higher impact of natural gas leaks for not only public safety, but also as a greenhouse gas emission with respect to environmental issues. Obviously, we have regulations from the federal government with DOT/PHMSA, but now requirements from the federal EPA as well," Wehnert said.

During the recovery, workers salvaged a blackboard with this written on it: "Oil and natural gas are East Texas' greatest mineral blessing. Without them this school would not be here and none of us would be here learning our lessons."

Perhaps one lesson to be learned is what the earth gives us, it can also take. Perhaps we should remember that as we learn more about the cause and effects of climate change. Perhaps we also need to remember not to skimp on our schools when officials look to cut costs.

"I did nothing in my studies or in my life to prepare for a story of the magnitude of the New London tragedy, nor has any story since that awful day equaled it," Cronkite wrote in his autobiography.

As for me, I'm glad I hadn't been born yet. ■

__Jeffrey Share__ is a Houston-based Hart Energy contributing editor specializing in midstream energy topics.

The flow of super-cold LNG coats unloading arms in ice at a European terminal's dock. *Source: Shutterstock/ Oleksandr Kalinichenko*

Freeze!

Producing super-cold LNG requires additional natural gas pretreatment and contaminant removal.

By Raj Palla and Trevor Smith

The oil and gas boom in the U.S. has made the country a major exporter of natural gas, in the form of liquefied natural gas (LNG), due to the large volume of inexpensive hydrocarbons found in shale gas. Natural gas is converted to LNG for transport overseas where placement of pipelines is not technically or economically feasible.

LNG—mainly composed of methane plus a small percent of ethane, propane and butane, and traces of nitrogen—is a gas that has been cooled to -260°F and converted to a liquid state. LNG in liquid form takes up approximately 1/600th the volume of natural gas as a vapor, making transportation more efficient and economical.

Demand for LNG is growing globally, particularly from customers in Asia. Demand growth in China, specifically, is driven by increasing demand for heating and cooking fuel, electricity generation and alternative transportation fuel.

China's LNG demand continues to grow at a rate of approximately 40% per year. As a result, small-scale LNG production and large-scale LNG import terminals are being utilized to meet the new demands.

Feed gas pretreatment and contaminant removal are necessary to ensure the liquefaction process runs reliably without any upsets or interruptions. If feed gas is not treated to the appropriate specifications, contaminants can cause corrosion or clogging in the plant equipment, particularly in the main heat exchanger, which can reduce operating efficiency and production up time.

Meeting LNG specifications

Feed gas for liquefaction must be pre-treated to ensure proper conditioning to ensure LNG plants run without operating problems and to meet LNG sales specifications. The typical specifications to be met are:

- Hydrogen sulfide (H_2S) removal to under 4 parts per million by volume (ppmv);
- Carbon dioxide (CO_2) to below 50/ppmv;
- Total sulfur to less than 10/ppmv;
- Water (H_2O) to less than 0.1/ppmv;
- Mercury to levels of 0.01 microgram per cubic meter; and
- Heavy hydrocarbons, C_5+, including benzene, to below freezing limits in cryogenic heat exchangers, i.e., less than 0.1 mol%, and benzene to less than 1/ppmv.

The feed gas flow rate, pressure and composition will determine the design and operation of the gas pre-treatment units.

Many LNG plants use pipeline gas as feed gas. Typical pipeline gas quality specifications are shown in the adjoining table. Over time, levels of contaminants may vary within the limits. Therefore, it helps to know which gas sources—shale gas, conventional gas or associated gas—are feeding the pipeline to an LNG plant in order to establish a proper design basis. This will aid in the selection of the most appropriate technology and process configuration for the gas pretreatment section.

Depending on the feed gas composition entering the LNG plant, the design of the pretreatment section may require mercury/H_2S removal, CO_2 removal, water removal and hydrocarbon removal or recovery.

Mercury removal

Mercury removal is required to avoid the potential risks of mercury corrosion of the aluminum heat exchangers in the downstream cryogenic section of an LNG plant. Alloys of aluminum are prone to liquid metal embrittlement, causing serious structural damage, particularly when liquid mercury comes into contact with air or water.

As raw feed gas enters the LNG plant, it first enters a separator and then flows into the mercury removal unit (MRU). During the mercury removal stage, one approach to solve this issue is to use non-regenerative metal sulfides to remove mercury. These high-capacity mercury adsorbents, which are typically engineered using a copper-based active component finely dispersed across an alumina substrate, can result in longer lifespan, reducing the lifecycle cost of mercury removal.

After the gas flows through the MRU, it continues into the acid gas removal process.

Typical Pipeline-Quality Gas Specifications

Characteristic	Specification
Mercury	1µg/Nm³-20 µg/Nm³
Carbon dioxide	2 mol %-3 mol%
Hydrogen sulfide	6 mg/m³-23 mg/m³ (4 ppmv-16 ppmv)
Total sulfur	115 mg/m³ (maximum) (approximately 80 ppmv)
Mercaptans/sulfides	Part of total sulfur specification
Water	65 mg/m³-112 mg/m³ (4 lb/MMft³-7 lb/MMft³)
Oxygen	0.01 mol% (maximum)
Hydrocarbon dewpoint	-10°C
Nitrogen	4 mol%-5 mol%
Sand, dust and free liquid	None

Source: Honeywell UOP

Acid gas

An acid gas removal unit (AGRU) mainly removes acidic components such as hydrogen sulfide, H_2S, and carbon dioxide, CO_2, from the feed gas stream to meet the LNG product total sulfur specification and to avoid CO_2 freezing—and subsequent blockages—in the cryogenic section of the liquefaction facility, respectively.

It also removes some amount of carbonyl sulfide, mercaptans, and other organic sulfur species that contribute to sulfur emissions. There are three commonly used solvent absorption processes (chemical absorption, physical absorption and the mixed solvents) for acid gas removal that can be used in LNG plants. However, formulated MDEA, or amine, solvents are most commonly used for H_2S and CO_2 removal.

For acid gas concentrations below 2%, NGL content below 2 gallons per thousand cubic feet, and feed flow capacities up to ~300 million cubic feet per day, Honeywell UOP has developed a simple and cost-effective "all in" adsorption process for LNG pretreatment. This solution eliminates the need for an amine unit and the management of liquid solvents.

All-in-SeparSIV is an adsorbent-based system that meets LNG specifications for CO_2 (and H_2S and RSH) and water and selectively removes C_5+ hydrocarbons and volatile organic compounds (BTEX)—benzene, toluene, ethylbenzene and xylene. The process is based on proven technology that selectively removes impurities through a unique combination of adsorbents and a comprehensive control system. The resulting product gas is able to meet LNG specifications with very little pressure drop. With the addition of a Pressure and Thermal Swing Adsorption (PTSA) unit, regen purge gas is minimized to approximately 10% of the feed flow rate, which enables this gas stream to be used as fuel gas or to be returned to the pipeline.

In the All-in-SeparSIV process, feed gas is fed to the Temperature Swing Adsorption (TSA) process unit, in which the impurities are adsorbed at low temperatures in a fixed-bed adsorber and desorbed by "swinging" the adsorbers from feed gas temperature (low) to regeneration temperatures (high) with hot regeneration gas.

With the proper portfolio of UOP proprietary adsorbents, multiple impurities including CO_2, water, C_5+ heavy hydrocarbons and BTEX can be removed simultaneously.

The adjoining process flow diagram depicts an All-in-SeparSIV system with a TSA followed by Pressure-Temperature Swing Adsorption (PTSA), which enables the regeneration purge gas to be minimized. In this configuration, water, C_8+ hydrocarbons and BTEX are removed by the TSA and CO_2 (and H_2S and RSH), while C_5-C_7 hydrocarbons are removed by the PTSA.

The treated gas exits the adsorbers and is then filtered and delivered to the customer's downstream processes.

Water and mercaptans

The molecular sieve unit design and performance are critical to assure all product specifications are met. Molecular sieves are used to dry the water-saturated gas leaving the AGRU to below 0.1 ppmv to avoid hydrate formation and freezing in the cryogenic section of the liquefaction unit. It can also be used for removal of mercaptans and other sulfur compounds to meet a total sulfur product specification of 10 parts per million or lower.

Molecular sieve dehydrators are typically installed in parallel beds of two, three or four vessels upstream of the liquefaction unit.

While moisture removal is traditionally done with smaller pore-sized molecular sieves, mercaptan and sulfur removal is done with larger pore types. 5A type molecular sieve is used for trace removal of H_2S and mainly for removal of light mercaptans (C1/C2-SH), while 13X molecular sieve is used for adsorption of heavy and branched mercaptans.

The molecular sieves are produced to such precision that there is no spread in the pore size distribution. The standard zeolites each have a specific pore size, unlike silica gels and activated alumina that exhibit a skewed bell-shaped distribution curve with a tail. The molecular sieves can therefore target very specific separations, as molecules which are larger than the pore sizes are excluded while smaller ones can enter the pore structure.

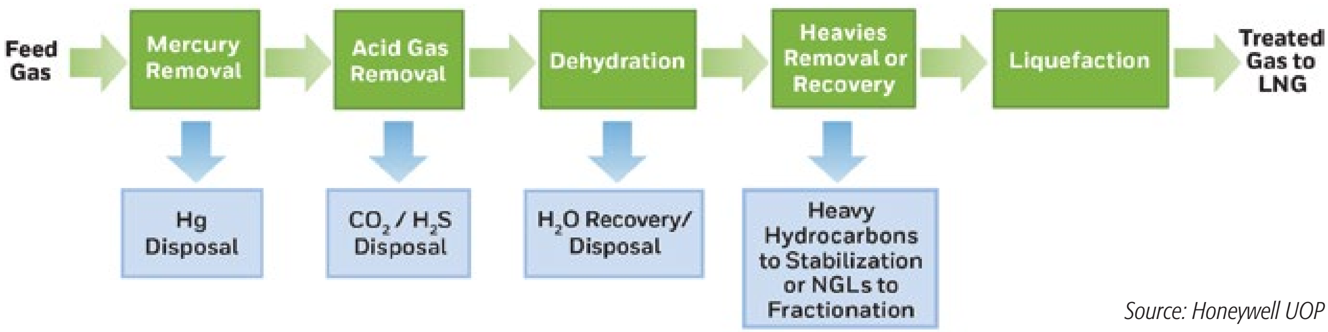
In order to optimize the size and improve the performance of the molecular sieve units in LNG facilities, various techniques have been developed in recent years. For example, using multi-layer bed configurations of dense molecular sieves of different sizes can reduce bed voidage and reduce vessel volume.

Using high-quality molecular sieves with superior properties and improved regeneration methods can extend product life and improve reliability while also providing cost savings.

If the gas is O_2-bearing, the feed gas flows into a closed-loop regeneration system. This system is used to mitigate water and sulfur formation by using a regeneration gas loop independent of the dry gas. This process removes all O_2 makeup from the feed gas to prevent corrosion to the carbon steel in the cooler parts of the regeneration section of the LNG plant.

Pipeline gas is usually considered lean with respect to ethane, propane and butane as these components are normally recovered to make higher value NGLs, while reducing the BTU value of the gas to acceptable levels. The levels of C_5+ hydrocarbons may become elevated if an upstream NGL recovery plant goes offline or if certain lean gas wells do not flow through an NGL recovery plant at all.

Typical Processing Blocks For LNG Pretreatment



Source: Honeywell UOP

Freeze-up problems

Since NGLs have already been extracted from pipeline gas in most cases, the primary purpose of removing heavy hydrocarbons upstream of an LNG facility is to prevent freezing in the downstream liquefaction section that could result in blockages and reduced capacity.

Using cryogenic technology is not the most cost-effective method to remove small quantities of C_5+ hydrocarbons, due to the high capital and operating costs associated with expanders, columns and compressors. Additionally, there are process challenges since there may not be sufficient liquids to provide scrub column reflux during startup, and it may be necessary to purchase NGLs to make the process work.

For lean gases where the primary purpose is removal of trace heavy hydrocarbons and not NGL production, adsorption technology such as the SeparSIV process can offer a significant advantage.

The primary reason for this is that an adsorbent-based system operates at high pressure with a low pressure drop and does not require an expander and compressor commonly found in an NGL extraction unit. The adsorption system also has the advantage of removing heavy components without removing lighter hydrocarbons.

Therefore, the LNG heating value is comparable to that of the pipeline feed gas.

The primary differences between a molecular sieve dehydration unit and an adsorbent-based hydrocarbon removal unit are that hydrocarbon removal units generally have a shorter adsorption time of two to three hours, use series cooling and heating regeneration, require the use of internal insulation for the adsorbers to minimize regeneration heat requirements, and use different adsorbents.

However, these flow schemes do have a successful history as they are similar to CO_2 removal in peakshaver units which run on fast cycles, and they may also use internal insulation to minimize the quantity of regeneration gas.

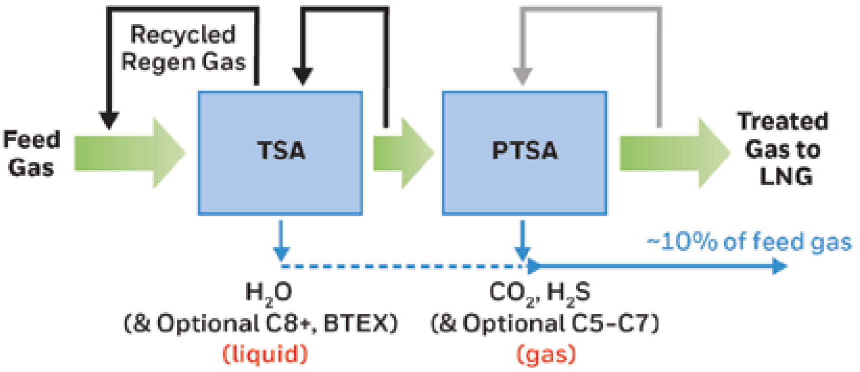
When feed gas is rich and the operator wishes to both recover NGLs and produce LNG, an NGL recovery unit can be integrated with the liquefaction unit. UOP refers to this as the Advanced Natural Gas Liquids Extraction (ANGLE) process. This integration makes use of shared equipment and refrigeration load to enable a very efficient and cost-effective solution to produce two value-generating products.

Cloud-based service

Some of challenges faced by operators include unplanned downtime, underperforming assets, managing human capital and meeting emission regulations. These challenges can be addressed in part by using Honeywell Connected Plant Services (CPS), a cloud-based service that will monitor, predict and improve plant performance by connecting plant data with Honeywell UOP analytical expertise. UOP's Process Reliability Advisor and Process Optimization Advisor assess unit operation and process constraints using key process indicators built from UOP's process models and operational experience.

CPS also provides early event detection to diagnose and mitigate issues, using embedded cause-and-effect relationship models. With this level of insight, a customer is able to improve process reliability—resulting in increased production yields and overall operational efficiency.

LNG Gas Treatment Flow



TSA–Temperature Swing Adsorption
PTSA–Pressure and Thermal Swing Adsorption

Source: Honeywell UOP

Modular equipment

Engineering, procurement and construction contractors, and LNG owners and operators often wish to have process technology delivered as a modular equipment package. Modular fabrication offers several advantages over stick-built construction, including quality control, faster execution schedule, having a single point of accountability, lower total installed cost and reduced risk of cost escalation and schedule delays.

Honeywell UOP offers pretreatment solutions on truck-transportable skids for small to mid-scale LNG projects and large modular designs up to 1 billion cubic feet per day for baseload LNG projects. UOP has an extensive modular portfolio that spans refining, petrochemicals, renewables and gas processing technologies that also has been defined for decades. With more than 1,500 modular units in operation, UOP's modular offerings provide a proven cost-effective solution to address the customer's gas treating challenges.

LNG is in high demand in many countries, creating an export opportunity for U.S. producers. The selection of the most appropriate gas pretreatment technologies for LNG plants being fed with pipeline quality gas is very case-specific.

The most relevant parameters to be considered in the selection will depend on the conditions and objectives of the LNG project, including the required capacity of the trains in the plant, the operations philosophy and the project investment criteria for the project. Depending on the composition of the feed gas, there are a variety of design options that operators can choose from when partnering with Honeywell UOP. ■

__Raj Palla__ is senior manager of gas processing, and __Trevor Smith__ is senior product line marketing manager for Honeywell UOP USA.

North America enjoys the world's most complete natural gas transmission network—a significant advantage as exports become more crucial to the continent's energy industry.
Source: Shutterstock/Denys Prykhodov

The Pipelines

The continent's outstanding interstate gas transmission grid enhances its growing role as the world's preeminent gas producer.

By Michelle Thompson

Interstate pipelines are being used throughout North America to safely connect the country's vast supply of natural gas with faraway markets and service areas. Though they account for just a portion of some 3 million miles of gas pipelines in the U.S. and Canada, interstate pipelines play an indisputable role in the overall energy cycle. The two nations share a closely intertwined gas transmission network that benefits both the U.S. and Canada.

Here are some of the largest interstate gas pipeline players and the major systems that they operate:

Enbridge Inc.

■ **Calgary, Alberta**

Enbridge Inc. ranked first on the 2019 Midstream 50 list of the sector's largest players, published by *Midstream Business*.

Its BC Pipeline system stretches from Fort Nelson in northeast British Columbia and from Gordondale, near the British Columbia-Alberta border, south to the Canada-U.S. border at Huntingdon, British Columbia/Sumas, Wash., outside Vancouver. The 1,776-mile BC Pipeline system serves markets throughout British Columbia, the U.S. Pacific Northwest and beyond.

It has a 2.9 billion cubic feet per day (Bcf/d) capacity.

The Southeast Supply Header (SESH) links the onshore gas supply basins of East Texas and North Louisiana to Southeast markets, now predominantly served by offshore gas supplies from the Gulf of Mexico. The 287-mile pipeline extends from the Perryville Hub in northeastern Louisiana to the Gulfstream Natural gas pipeline system in Mobile County, Ala. A joint venture between subsidiaries of Enbridge Inc. and

Enable Midstream, SESH interconnects with a variety of interstate natural gas pipelines, providing additional supply opportunities for markets in the southeast and northeast U.S. It has a peak capacity of 1.1 Bcf/d.

The Big Sandy Pipeline interconnects with the Tennessee Gas Pipeline system. It serves as a link between the Huron Shale and Appalachian Basin's gas supplies and markets in the Mid-Atlantic and Northeast. The 67-mile line, which has a 0.23 Bcf/d capacity, is located in eastern Kentucky.

Enbridge's Alliance Pipeline system consists of a 2,391-mile integrated U.S. and Canadian gas gathering and transmission pipeline system that delivers gas from the Western Canadian Sedimentary Basin and the Williston Basin to the Chicago market hub. The U.S. portion of the system includes 967 miles of infrastructure. Enbridge has a 50% ownership interest in the Alliance Pipeline.

The Texas Eastern Transmission line links Texas and the Gulf Coast with Mid-Atlantic and Northeast markets. The 9,071-mile line can transport 11.69 Bcf/d of gas. It connects to Enbridge's East Tennessee Natural Gas Pipeline and its Algonquin Gas Transmission system.

LNG-sourced gas travels throughout New England and Atlantic Canada on Enbridge's Maritimes & Northeast Pipeline. The 887-mile line runs from Nova Scotia to the Algonquin Gas Transmission Hubline near Beverly, Mass. It has a capacity of 0.83 Bcf/d in the U.S. and 0.55 Bcf/d in Canada.

About 3.08 Bcf/d of gas travels through 1,140 miles of pipeline on the Algonquin Gas Transmission system. Product passes through New Jersey, New York, Connecticut, Rhode Island and Massachusetts before connecting to the Texas Eastern Transmission pipeline and the Maritimes & Northeast pipeline.

Spanning 348 miles from Joliet, Ill., to Sarnia, Ont., the Vector Pipeline delivers gas to local distribution and end-user customers in Illinois, Indiana, Michigan and Ontario, Canada. The system has an average capacity of 1.3 Bcf/d.

The 517-mile Sabal Trail Transmission LLC transports more than 1 Bcf/d of gas through Alabama, Georgia and Florida. Gas is delivered to Florida Power & Light Co. and Duke Energy Florida. The project is a joint venture of Enbridge Inc., NextEra Energy Inc. and Duke Energy Corp.

Energy Transfer Partners

■ **Dallas**

Energy Transfer holds the No. 2 position on the Midstream 50.

It owns and operates about 12,200 miles of interstate gas pipelines that have a total capacity of about 10.3 Bcf/d. Through its joint venture interests, the company has another 6,750 miles of pipelines and 10.5 Bcf/d of transportation capacity.

Its 2,614-mile Transwestern Pipeline spans the Permian Basin in West Texas and eastern New Mexico, the San Juan Basin in northwestern New Mexico and southern Colorado, and the Anadarko Basin in the Texas and Oklahoma panhandles. With a 2.1 Bcf/d capacity, the system can connect with Texas and

Boardwalk Pipeline's Hardinsburg, Ky., compressor station keeps gas flowing through its Texas Gas Transmission system.
Source: Boardwalk Pipeline Partners

The Opal, Wyo., gas processing plant, part of Williams' Northwest Pipeline system, also serves as a major pipeline and storage hub for the Intermountain West. *Source: The Williams Cos. Inc.*

Midcontinent pipelines and gas market hubs, as well as major western markets in Arizona, Nevada and California.

The 195-mile Tiger Pipeline passes through the central Haynesville Shale and ends near Delhi, La. With a 2.4 Bcf/d capacity, the line interconnects to numerous interstate pipelines at various points in Louisiana.

With a capacity of 2 Bcf/d, Energy Transfer's Sea Robin Pipeline includes two offshore Louisiana gas supply pipelines that travel 120 miles into the Gulf of Mexico. It serves the Henry Hub in Louisiana, a key pipeline interconnection and gas market pricing point.

Energy Transfer also operates several interstate pipelines that it has partial interests in.

The Florida Gas Transmission (FGT) system includes 5,344 miles of pipelines running from South Texas through the Gulf Coast region to South Florida. With a 3.4 Bcf/d mainline capacity, the FGT delivers more than 60% of the natural gas consumed in Florida, making it the premier transporter of gas to the state's energy market.

The Panhandle Eastern Pipeline runs from producing areas in the Texas and Oklahoma panhandles and the Midcontinent region's Anadarko Basin in Oklahoma and Kansas, to Missouri, Illinois, Indiana, Ohio and Michigan markets. It includes about 6,400 miles of pipeline and has a 2.8 Bcf/d capacity. It is owned by an ETP Holdco subsidiary.

Trunkline Gas Co.'s transmission system extends about 1,400 miles from the Texas and Louisiana Gulf Coast regions through Arkansas, Mississippi, Tennessee, Kentucky, Illinois, Indiana and Michigan. It has a 0.9 Bcf/d capacity. The pipeline is owned by an ETP Holdco subsidiary.

The 185-mile Fayetteville Express pipeline originates near Conway County, Ark., and moves east toward Panola County, Miss., with multiple interconnections along the route. It has a 2 Bcf/d capacity.

A comparatively new player built to move gas out of the booming Marcellus and Utica plays, Rover Pipeline can transport 3.25 Bcf/d from processing plants in West Virginia, eastern Ohio and western Pennsylvania for delivery to other pipeline interconnects in Ohio and Michigan. From there, the 713-mile line distributes gas to markets throughout the U.S. and Ontario.

TC Energy

■ Calgary, Alberta

TC Energy ranks No. 5 on the Midstream 50.

If you haven't heard, TransCanada Corp. recently changed its name to TC Energy. But one thing hasn't changed: With more than 57,000 miles of pipeline, it remains one of North America's largest gas pipeline networks.

Measuring 10,600 miles in length, TC Energy's ANR pipeline is one of North America's largest gas pipeline systems. It runs from Texas, Oklahoma and Louisiana to Wisconsin, Michigan, Illinois and Ohio. The pipeline has a peak delivery capacity of more than 6 Bcf/d.

Running 302 miles from Wyoming and Montana to North Dakota, the Bison Pipeline offers 407 million cubic feet per day (MMcf/d) of operational capacity. Once the pipeline reaches North Dakota, it connects with other interstate pipelines.

The 3,368-mile Columbia Gulf Transmission Pipeline is connected to every major pipeline system along the Gulf Coast. With a 1.7 Bcf/d capacity, it serves markets in Louisiana, Mississippi, Tennessee and Kentucky. The Columbia network consists of 12,000 miles of pipelines that transport about 3 Bcf/d of gas to 10 states from New York to the Gulf of Mexico.

Operating in Indiana and Ohio, the 202-mile Crossroads Pipeline brings Canadian and U.S. gas to Indiana, Ohio, Illinois and Michigan. It has multiple interconnects that allow it to access gas produced in the Rockies, Gulf Coast, Permian and Canada. It has a 300 MMcf/d capacity.

The Gas Transmission Northwest system transports Canadian gas to Washington, Oregon and California communities. The 1,353-mile line has a 2.9 Bcf/d capacity.

The 2,115-mile Great Lakes Gas Transmission pipeline links western Canada supply to markets in Minnesota,

ONEOK's addition of its Roadrunner system added critical new gas pipeline capacity to the capacity-constrained Permian Basin. *Source: ONEOK Inc.*

Wisconsin, Michigan and Eastern Canada. Its average capacity is 2.4 Bcf/d.

The 416-mile Iroquois Gas Transmission System runs from Waddington, N.Y., on the Canadian border through New York and western Connecticut before ending in the Bronx, N.Y. The system is a limited partnership of four U.S. and Canadian companies. Its capacity is dependent on pipeline conditions.

TC Energy's NOVA Gas Transmission Ltd. (NGTL) System connects Western Canada Sedimentary Basin (WCS) production to markets throughout Canada and the U.S. The 15,266-mile line delivers about 11 Bcf/d of gas to markets in Alberta, British Columbia, the U.S. Pacific Northwest, California, the Midwestern U.S. and Eastern Canada.

The Northern Border Pipeline serves as a link between WCS gas reserves and the Midwestern U.S. market. The 1,250-mile line brings 2.4 Bcf/d to Montana, North Dakota, South Dakota, Minnesota, Iowa and the Chicago area.

Running 305 miles through Oregon, California and Nevada, the Tuscarora Pipeline delivers 0.23 Bcf/d of gas from the WCS, Rocky Mountains and U.S. basins.

Kinder Morgan Inc.

■ **Houston**

Kinder Morgan Inc. ranked No. 3 on the latest Midstream 50 list.

Kinder Morgan operates—or owns an interest in—about 70,000 miles of gas pipelines, making it the largest gas pipeline network in North America.

Through the 11,750-mile Tennessee Gas Pipeline (TGP), some 7.5 Bcf/d can move from Louisiana, the Gulf of Mexico and South Texas to the northeastern U.S. Destinations include New York City and Boston.

The TGP recently completed a number of expansions. Its Broad Run expansion helped create 790,000 dekatherms per day (Dth/d) of incremental firm transportation capacity from the southwest Marcellus and Utica plays to delivery points in Mississippi and Louisiana. Its Southwest Louisiana Supply Expansion project added 900,000 Dth/d of incremental firm transportation capacity from multiple supply basins to the Cameron LNG export facility. Finally, the TGP Lone Star Expansion projected provided 300,000 Dth/d of incremental firm transportation capacity from various Mississippi receipt points to Cheniere Energy's brand-new Corpus Christi LNG facility in Texas.

A joint venture between Kinder Morgan and Energy Transfer, the 512-mile Midcontinent Express Pipeline begins near Bennington, Okla., near the Oklahoma-Texas border, and passes through northern Louisiana and central Mississippi to an interconnect with the Transcontinental Gas Pipeline System in Butler, Ala. It has a 1.8 Bcf/d capacity.

Southern Natural Gas's 6,900-mile pipeline system runs from gas supply basins in Louisiana, Mississippi and Alabama to markets in Louisiana, Mississippi, Alabama, Florida, Georgia, South Carolina and Tennessee. The system was recently expanded in Georgia to provide 370,000 Dth/d of incremental, long-term firm transportation capacity to the Southeast market. Meantime, the Elba Express and SNG expansion added 54,000 Dth/d of incremental gas transportation for markets in Georgia, South Carolina and northern Florida.

Cheyenne Plains Gas Pipeline's 410-mile route begins near the Wyoming-Colorado border and runs through south-central Kansas. With an 0.8 Bcf/d capacity, Cheyenne Plains serves markets in the Midwest with connections to several Midcontinent pipelines in south-central Kansas.

The 4,350-mile Colorado Interstate Gas system moves gas from production areas in the U.S. Rocky Mountains to customers in Colorado and Wyoming. It indirectly serves customers in the Midwest, Southwest, California and Pacific Northwest with a 5.15 Bcf/d capacity.

Stretching 10,140 miles, the El Paso Natural Gas pipeline system transports gas from the San Juan, Permian and Anadarko basins to California, Arizona, Nevada, New Mexico, Oklahoma, Texas and Northern Mexico.

Ruby Pipeline is a 680-mile system that can deliver up to 1.5 Bcf/d from

Wyoming to Oregon, ultimately providing gas to consumers in California, Nevada and the Pacific Northwest.

The 850-mile Wyoming Interstate pipeline system runs from western Wyoming to northeast Colorado, with several lateral pipelines that extend from various interconnections along the mainline into western Colorado, northeastern Wyoming and eastern Utah.

The Williams Cos. Inc.

■ **Tulsa, Okla.**

Williams ranks No. 6 on the Midstream 50.

Williams owns and operates three interstate pipelines, including Transco, the nation's largest-volume gas pipeline system. Transco delivers natural gas to customers through its approximately 10,000-mile pipeline network, which has a mainline that extends nearly 1,800 miles between South Texas and New York City. The system is a major provider of gas services that reach U.S. markets in 12 Southeast and Atlantic Seaboard states, including major metropolitan areas in New York, New Jersey and Pennsylvania.

It has a capacity of 16.9 Dth/d.

Williams' Northwest Pipeline, with headquarters in Salt Lake City, provided the first gas service to the U.S. Pacific Northwest. It continues to serve as a primary artery for the transmission of natural gas to the Pacific Northwest and Intermountain Region. It began as a 1,500-mile pipeline in the 1950s but has since grown to become an approximately 4,000-mile bi-directional transmission system crossing the states of Washington, Oregon, Idaho, Wyoming, Utah and Colorado. Northwest's bi-directional system provides access to British Columbia, Alberta, Rocky Mountain and New Mexico San Juan Basin gas supplies.

Finally, the 745-mile Gulfstream interstate transmission pipeline delivers gas diagonally across the Gulf of Mexico from Mobile County, Ala., to meet Florida's rapidly growing residential and power needs. Williams owns 50% of Gulfstream. Spectra, an Enbridge affiliate, and its affiliates own the other 50%. Williams serves as Gulfstream's operator. Capacity is 1.31 Bcf/d. It is the Gulf of Mexico's largest pipeline.

Tallgrass Energy LP

■ **Leawood, Kan.**

Tallgrass is No. 25 on the Midstream 50. Tallgrass Energy LP's natural gas transportation systems include more than 6,800 miles of pipeline.

Its 1,700-mile Rockies Express (REX) pipeline stretches from Colorado and Wyoming to eastern Ohio, with access to major gas supply basins in the Rocky Mountain region to the west and Ohio and Pennsylvania fields at its east end. Bi-directional, it boasts about 1.8 Bcf/d of west-to-east capacity and about 2.6 Bcf/d of east-to-west capacity, totaling about 4.4 Bcf/d of daily long-haul capacity.

The 450-mile Trailblazer Pipeline begins along the Wyoming-Colorado border and extends to Beatrice, Neb., interconnecting with large interstate pipelines that transport gas to major consumer markets, such as Chicago, the upper Midwest and the Northeast.

Tallgrass Interstate Gas Transmission's (TIGT's) 4,650-mile line serves Colorado, Kansas, Nebraska, Wyoming and Missouri. The combined TIGT and Trailblazer transportation capacity is about 2 Bcf/d.

Projects underway include the Cheyenne Connector, a 70-mile pipeline designed to move gas from processing facilities in the Denver-Julesburg Basin in Weld County, Colo., to the REX Cheyenne Hub on the Colorado-Wyoming border. Its initial capacity will be 0.6 Bcf/d. The line is expected to be in service by the fourth quarter of 2019.

Boardwalk Pipeline Partners LP

■ **Houston**

Formerly one of the top-ranked firms on the Midstream 50, Boardwalk left the roster in 2018 when parent Loews Corp. bought Boardwalk's remaining publicly traded MLP units and took the firm private.

Through its subsidiaries, Boardwalk Pipeline Partners LP owns and operates about 13,880 miles of interconnected gas pipelines that serve customers throughout the country.

Texas Gas Transmission LLC's 5,980-mile pipeline averages 2.4 Bcf/d. It begins in Louisiana and travels through Arkansas, Mississippi, Tennessee, Kentucky, Indiana and Ohio, with smaller lines extending into Illinois. Its market areas span eight states in the South and Midwest.

The 7,275-mile Gulf South Pipeline Co. moves about 2.8 Bcf/d from basins between Texas and Alabama to markets in the Northeast, Midwest and Southeast through interconnections with third-party pipelines. Markets served include New Orleans, La., Jackson, Miss., Mobile, Al., and Pensacola, Fl.

Beginning near Sherman, Texas, near the Oklahoma border, and extending to Perryville, La., Gulf Crossing Pipeline Co. provides takeaway capacity from the Barnett Shale in Texas and the Caney/Woodford Shale in Oklahoma. With a 1.1 Bcf/d capacity, the 375-mile system

This route marker guards a Natural Gas Pipeline of America right-of-way in Illinois. *Source: Kinder Morgan Inc.*

Canada's BC Pipeline joins Williams' Northwest Pipeline at this border crossing outside Sumas, Wash. *Source: The Williams Cos. Inc.*

indirectly serves markets in the Midwest, Northeast and Southeast.

ONEOK Inc.

■ **Tulsa, Okla.**

ONEOK ranked No. 10 on this year's Midstream 50.

ONEOK's interstate pipelines transport gas through Montana, North Dakota, South Dakota, Minnesota, Wisconsin, Iowa, Illinois, Indiana, Kentucky, Tennessee, Oklahoma, Texas and New Mexico. It owns about 1,452 miles of transmission pipe with about 3.2 Bcf/d of peak transportation capacity.

The Guardian Pipeline runs from the Chicago Hub near Joliet, Ill., to Green Bay, Wis. The 252-mile system has a 1,287 Dth/d capacity and accesses all the major North American supply basins.

Viking connects with major pipeline systems—including TransCanada, Northern Natural, Great Lakes Transmission, and ANR—and serves strategic markets in North Dakota, Minnesota and Wisconsin. Midwestern Gas Transmission is a 350-mile pipeline that runs from Portland, Tenn., to Joliet, Ill., connecting with other major interstate systems along the way. It has a 0.65 Bcf/d capacity.

Its Roadrunner and ONEOK WesTex systems move Permian Basin gas south to the U.S.-Mexico border and to domestic customers. Roadrunner has some 200 miles of pipeline, designed to transport up to 0.64 Bcf/d, most of which goes to Mexico.

Dominion Energy Inc.

■ **Richmond, Va.**

Dominion Midstream Partners, another Midstream 50 mainstay, was rolled into its parent, Dominion Energy, early this year.

Dominion's Salt Lake City-based Questar Pipeline owns and operates 1,888 miles of pipeline with a total capacity of 2,530 Dth/d. Its interstate system is based in the Rocky Mountains near large gas reserves in six major producing areas, including the Greater Green River, Uinta and Piceance basins. It transports gas from those areas to other major pipeline systems for delivery to markets in the West and Midwest.

Overthrust Pipeline delivers gas to eastern and western markets through its 261-mile, 2,400 Dth/d system. It provides transportation services for producers in multiple Rockies-producing basins with interconnects to several major pipeline systems. A 43-mile loop between Kanda and Blacks Fork in Wyoming was completed in 2011, increasing firm capacity by 800 Dth/d for deliveries to the west and 50,000 Dth/d for deliveries to the east.

EQM Midstream Partners

■ **Pittsburgh**

With primary ownership by parent EQT Corp., EQM ranks No. 20 on the Midstream 50.

EQM Midstream Partners has a significant ownership interest in, and will operate, the Mountain Valley Pipeline (MVP), which is currently more than 85% complete and targets an in-service date of mid-2020. MVP spans about 300 miles from northwestern West Virginia to southern Virginia.

MVP is expected to provide up to 2 Bcf/d of firm transmission capacity to markets in the mid-Atlantic and southeastern regions of the U.S.

The MVP Southgate project is a proposed 70-mile interstate pipeline that will extend from the MVP at Pittsylvania County, Va., to new delivery points in Rockingham and Alamance counties in North Carolina.

The project is backed by a 0.3 Bcf/d firm capacity commitment from PSNC Energy. The project has a targeted in-service date of fourth-quarter 2020.

EQM's 950-mile Equitrans Pipeline system is a major transmission system serving the booming Marcellus and Utica plays, which have emerged as a dominant natural gas supply region for North American—and the world. It connects to seven interstate pipelines and local distribution companies and has a total throughput capacity of approximately 4.4 Bcf per day. ■

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