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Joseph Reinhart discusses midstream challenges, p. 42

MIDSTREAM UPDATE

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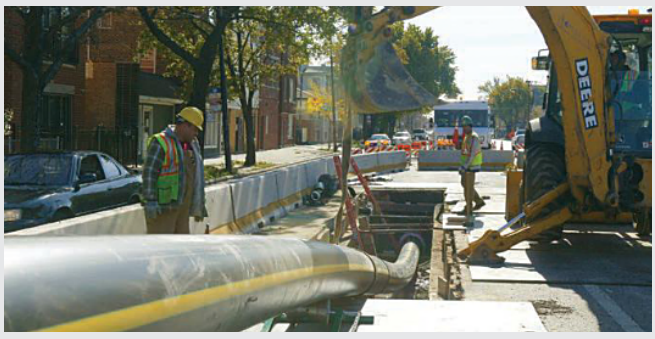
Pipeline & Gas Journal's 2015 ANNUAL 500 REPORT

On The Cover

Midstream operators, including those in the New England and Appalachian regions, continue to face challenges in expanding their infrastructure.

Next Month



The December issue of *P&GJ* contains news from the American Public Gas Association, reports on plastic pipe and line pipe, information on operators in the Upper Midwest transitioning from coal to natural gas, and lost-and-unaccounted-for gas.

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EDITOR'S NOTEBOOK

Jeff Share
Editor

As President Obama smugly twiddles his thumbs and decides when he'll put Keystone out of its misery, sides are being taken, mostly along political lines, in the real debate that will decide the fate of the domestic oil industry: ending the outdated 1975 ban on crude oil exports.

Obama, of course, sees no need to lift the ban, though he says he might reconsider IF the oil industry gives up its tax breaks.

Refineries and various business groups favor the ban, fearing its end would raise their costs. The environmental lobby, with its deep pockets, has become increasingly entrenched in the administration and fights anything that even hints of supporting fossil fuels.

On Capitol Hill, the GOP-dominated House has approved a bill ending the ban. A Senate panel endorsing exports passed a bill but not before several Democratic members voiced skepticism. Their support is contingent on receiving serious concessions from their GOP colleagues. So, let the horse trading begin, because without an acceptable compromise, Obama will quickly issue a veto which Congress won't be able to override.

Here's an example of the rancor over lifting the ban: GOP criticism of the nuclear deal that puts Iranian crude back on the market which will apply even more pressure on U.S. producers. A GOP-dominated Senate panel added an amendment requiring that Iran use the revenue to compensate terrorism victims who won cases in U.S. courts against Iran. That will kill the bill. The panel killed suggestions by Sen. Robert Menendez (D-NJ) that would delay repeal pending a study of potential job losses from the policy change, and would block exports until the U.S. determines it has produced enough crude to satisfy domestic demand.

"I think Americans would be appalled to know that we're considering exporting U.S. oil at a time that we're still reliant on foreign oil — to know that instead of investing in U.S. refineries and creating good-paying jobs at home, we are considering a policy that would send those jobs to refineries overseas," he said.

That may satisfy the anti-fossil fuel lobby but the comments lack logic. Some U.S. refineries need heavy crude not produced here. And, as Sen. Richard Shelby (R-AL) said, "28% of U.S. refining capacity is owned by foreign interests who will always import heavy sour oil produced and imported from their own country."

Heidi Heitkamp (D-ND) wants to protect her state from the economic destruction endangering the Bakken Shale. Since we export refined products such as gasoline and diesel, why can't unprocessed crude be afforded equal treatment? How does exporting refined products help control prices at the pump?

Most experts including the EIA agree that exports would raise U.S. crude prices modestly though gasoline prices would be the same or slightly lower. Some Democrats want to combine exports with other energy provisions, such as renewable energy programs in the fight against climate change, ending the billions in tax incentives for the oil industry or imposing a new per-barrel production tax to fund highways and other infrastructure. Sens. Joe Donnelly (D-IN) and Jon Tester (D-MT) want to protect refinery jobs as part of a compromise; Donnelly suggests mandating U.S. steel for any pipeline that facilitates crude exports.

If domestic crude is too valuable to export, and we want to break our dependence on foreign oil as Menendez suggests, stop appeasing the fossil-fuel haters by subjecting the industry to every conceivable roadblock. If oil is so important to our economy, why continue to let it be sold for less than the price of water? Unless we keep the domestic industry at work, our production will dwindle, forcing us to import more instead of less, raising prices at the pump, and costing tens of thousands of high-paying jobs.

The industry is readying TV ads for the export bill. Why not air an ad explaining why domestic production keeps gas prices low? That the public gets. Speaking of TV, I saw a rather serendipitous message after writing this that spoke of that evening's Share-a-Thon. Who would use my name so cavalierly? I tuned in and saw this was Jimmy Swaggart's annual fundraiser. Now whether he's praying, crying, singing or doing whatever, the rev has always been my favorite TV preacher.

As I watched, I wondered how much would he charge to say a prayer for our industry, and that government does the right thing? ***P&GJ***

Lone Star Editorial Award winner

Pipeline & Gas Journal

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3 Workers Killed at Williams Gas Plant Explosion in LA

An explosion at a Louisiana natural gas facility on Oct. 8 left three workers dead and two seriously injured, police said. The explosion happened about 11 a.m. at a facility owned by the Transcontinental Gas Pipeline Co., a subsidiary of major natural gas supplier Williams Partners, authorities said. The facility is located on a small highway near the oil and gas city of Houma.

The workers killed and injured were contractors doing maintenance work when the explosion occurred, Williams Partners said in a statement. The names of the victims and the company or companies they worked for were not released immediately. Williams Partners said its 13 workers at the facility were unharmed.

In the statement, Williams Partners said the facility was shut down and no gas was flowing through its pipeline at the time of the explosion. The company said service to its customers had not been interrupted. The bodies of the three workers were found following the explosion, said state police Trooper Evan Harrell. Black smoke billowed from the facility hours after the explosion. Officials said the smoke posed no health risks, and no evacuations were ordered.

The company said the maintenance work involved a "slug catcher," a tank designed to separate liquids and impurities from the natural gas stream.

California Tightens Responses to Future Energy Spills

Just months after a pipeline rupture dumped 20,000 gallons of oil into the ocean near Santa Barbara, on Oct. 8 California Gov. Jerry Brown signed a package of bills aimed at preventing and better responding to future spills. Brown said he signed the bills "in order to more fully protect our inland and coastal communities and environments from the harm of oil spills."

The *Los Angeles Times* reported that the state fire marshal now must annually inspect all intrastate pipelines under its jurisdiction by approving SB 295. The May 19 spill at Refugio State Beach involved a section of corroded pipeline that was being inspected every other year. Over 100,000 gallons spilled, with one-fifth of it reaching the ocean.

Brown also approved a bill, AB 864, requiring oil pipelines in environmentally sensitive areas be fitted with remote leak detectors and automatic shut-off valves.

A third bill, SB 414, seeks to speed response to spills by enlisting commercial fisherman and other boat operators to help contain leaks in their area. They would be outfitted with containment gear.

"The devastating effects from the oil spill this year in Santa Barbara County impacted birds, mammals and other marine life and caused the closure of beaches and fishing resulting in economic losses," Brown wrote in a signing message.

"Our coastline and surrounding environments contribute to the great and unique landscape of California. These bills improve planning for and prevention of oil spills and our response when spills occur."

The measures were introduced by Sen. Hannah-Beth Jackson and Assemblyman Das Williams, both Democrats from Santa Barbara. "The Refugio Oil Spill gave us a prime and devastating example of a defective pipeline that was not equipped with leak detection technology and automatic shut-off valves," Williams said.

The leak detectors and shut-off valves must be used in replacement pipelines in ecologically sensitive areas in the coastal zone starting Jan. 1, 2018. Existing pipelines must be retrofitted by Jan. 1, 2020, with plans submitted by July 1, 2018.

There was no official opposition to the bills, according to an analyst for the Legislature. The Western States Petroleum Association, whose members include pipeline operators, was neutral on the bills.

Willbros Group Sells Professional Services Business for $130 Million

Willbros Group, Inc. announced Oct. 6 a deal to sell its Professional Services segment to TRC Companies, Inc. for $130 million cash. The agreement is binding and the sale is expected to close before the end of November. Willbros will retain $43 million of the net proceeds to maintain its current liquidity and working capital. The balance of the proceeds, net of closing and transaction expenses, will be used to reduce the company's term loan debt.

"This transaction clearly enables us to present a much improved balance sheet to meet the expectations of our customers and investors. We set out a year ago to improve our capital structure and our operating efficiency," said John T. McNabb, II, chairman and CEO. "We have restructured our Oil & Gas segment with a new management team and a focus on our areas of strength and competency. We have resized our corporate and segment G&A expenses and have significantly reduced our long term debt, optimizing our capital structure.

"Our three segments are qualified both operationally and financially for the markets we address, and we can now focus on building backlog and delivering net income. With the overall transformation of Willbros, we are confident that we can achieve stable, predictable and improved performance in 2016.

"Our next milestone events will be completion of the sale of our Professional Services segment and a smaller non-strategic business unit, and we are confident that we will complete both transactions in the near-term. With these sales completed, since the end of 2014 the company will have reduced its term loan debt from $270 million to less than $100 million."

Dominion Transmission Setting Up Midstream Operation

Dominion Transmission Inc. (DTI) plans to contribute all its gathering and processing facilities to a new, affiliated midstream company, Dominion Gathering & Processing Inc. Dominion Resources Inc. pipeline company, also known as DTI, will no longer provide any gathering or products extraction services.

DTI told the Federal Energy Regulatory Commission (FERC) the rise of shale gas, especially the Marcellus and Utica formations, has changed the look of midstream services in the Appalachian region. Its gathering systems in Appalachia were developed decades ago by predecessor companies in support of a bundled merchant function.

Dominion calculated total net book value of the facilities as of April 1, 2016, the intended transfer date, will be about $434 million. DTI will remain one of the nation's largest interstate natural gas pipeline and storage companies.

Study: No Fracking Bonanza for California's Monterey Shale

A U.S. Geological Survey report last month downgraded the fracking potential of California's vast Monterey Shale oil deposits. The study is the latest to lower a 2011 federal energy estimate that billed the Monterey Shale as a game-changer for U.S. oil, with what was then estimated at 13.7 billion bbls of recoverable oil overall.

Instead, the USGS's new study said, the most oil-rich portion of the giant shale formation holds just 21 MMbbls of oil that can be recovered by intensive methods, such as hydraulic fracturing. The report looked only at the San Joaquin Basin, one of four basins that make up the 1,750-square-mile Monterey Shale formation. Upcoming USGS reports will estimate the recoverable petroleum in the other three basins.

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IN THE **NEWS**

Mountain Valley Pipeline to Service Virginia via Partnership with Roanoke Gas

Mountain Valley Pipeline, LLC and RGC Midstream, LLC will deliver natural gas to several Virginia communities along the proposed Mountain Valley Pipeline (MVP) route.

RGC Midstream, LLC, a subsidiary of RGC Resources, Inc. will acquire a 1% ownership interest in Mountain Valley which is a joint venture between EQT Midstream Partners, LP, majority owner and operator of the proposed pipeline; and affiliates of NextEra Energy, Inc. WGL Holdings, Inc. and Vega Energy Partners, Ltd. Roanoke Gas Co. will become a shipper on the pipeline to expand its southwest Virginia customer base.

With its connection to EQT Midstream Partners' existing Equitrans system in West Virginia, MVP addresses infrastructure constraints associated with the development of natural gas from the Marcellus and Utica shale plays, while offering critical supply diversity to meet the demand for natural gas across the mid-Atlantic and Southeast.

The MVP is a 300-mile long, 42-inch pipeline with an estimated total cost of $3-3.5 billion. Mountain Valley Pipeline, LLC expects to file a certificate application with FERC shortly and is targeting a full in-service in late 2018.

GE Moving Gas Engine Plant from Waukesha to Canada

GE Power & Water will stop manufacturing gas engines in Waukesha, WI and will open a new facility to build engines in Canada that will also have back-up capacity to manufacture diesel engine components for GE Transportation.

GE employs 350 at its manufacturing facility in Waukesha, building gas engines for compression, mechanical drive and power generation applications. GE notified employees in Waukesha and over 400 U.S. suppliers of its plans.

GE said it plans to build a US$265 million state-of-the-art "Brilliant Factory" in Canada that will optimize efficiency and streamline production using data, analytics and software. The factory is expected to be completed in 20 months and will be a flexible production facility that can expand over time and support manufacturing requirements for other GE businesses.

GE said it will build its facility in Canada in order to access additional support from the country's export credit agency, Export Development Canada (EDC). The authorization for the U.S. export credit agency – the Export-Import Bank – lapsed July 1.

Gulfport Energy, Rice Energy Forming JV in Ohio

Gulfport Energy Corp. announced an agreement with Rice Midstream Holdings, LLC, a wholly owned subsidiary of Rice Energy Inc., to form a midstream joint venture to develop natural gas gathering and water services assets to support Gulfport's dry gas Utica Shale development in eastern Belmont County and Monroe County, OH. The JV will be supported by long-term, fee-based service agreements with Gulfport.

Gulfport will own 25% of the JV and Rice will own the remaining 75%. Rice will be responsible for constructing and operating the JV's assets:

- A dry gas gathering system with capacity to gather over 1.8 MMdth/d of natural gas consisting of 165 miles of high- and low-pressure, 12- to 30-inch gathering pipelines with multiple interconnections to interstate pipelines, including Rockies Express, ET Rover, TETCO and Dominion East Ohio.
- 50,000 hp of compression for gathering and delivery into downstream interstate pipelines.

Pension Plan Board Eyes $1 Billion Investment in Western Canada Midstream

Canada Pension Plan Investment Board will provide $1 billion in funding for midstream acquisitions in Western Canada that will be identified and evaluated by Calgary-based Wolf Infrastructure Inc. The focus will be on processing facilities, gathering systems, pipelines, storage facilities and terminals used by oil, gas and liquids producers.

"As a long-term investor, we see midstream as an attractive sector given the significant investment required in Western Canada to support growth in natural gas and natural gas liquids production in new areas," said Avik Dey, CPPIB's managing director for natural resources.

Crimson Pipeline Acquiring Chevron Assets

Long Beach, CA-based Crimson Pipeline L.P. will expand to central and northern California upon completion of acquisition of Chevron Pipe Line Company's (CPL) KLM Pipeline and ancillary assets and Western San Joaquin Laterals (WSJ).

Larry Alexander, president and CEO of Crimson, said, "This acquisition from Chevron Pipe Line Co. complements our existing operations and will enhance Crimson's capacity to safely transport crude oil throughout California."

The KLM Pipeline transports crude oil from California's prolific San Joaquin Valley to San Francisco Bay area refiners, including Tesoro Golden Eagle Refinery, Valero Benicia Refinery and Shell Martinez Refinery. The KLM Pipeline system includes 295 miles with a capacity of 90,000 bpd.

With this acquisition, Crimson's California pipeline network will traverse about 1,000 miles across northern, central and southern California. Once operations can begin, the acquisition will expand Crimson's transportation capacity in California from 160,000 to 250,000 bpd.

Now ND Facing Too Much New Housing

After struggling to house thousands of migrant roughnecks during the boom, North Dakota faces a new real estate crisis: The frenzied drilling that made it No. 1 in personal-income growth and job creation for five consecutive years hasn't lasted long enough to support the oil-fueled building explosion, according to Bloomberg.

Civic leaders and developers say many new units were already in the pipeline, and they anticipate another influx of workers when oil prices rise again. But for now, hundreds of dwellings approved during the heady days are rising, skeletons of wood and cement surrounded by rolling grasslands, with too few residents who can afford them.

"We are overbuilt," said Dan Kalil, a commissioner in Williams County in the heart of the Bakken. "I am concerned about having hundreds of $200-a-month apartments in the future."

Louisiana Company Proposes LNG Export Project

Baton Rouge-based G2 LNG announced Oct. 5 that it plans to construct an $11 billion LNG export facility on the ship channel in Cameron Parish. If built, it would be one of the largest capital investments in Louisiana history.

Before construction can begin, the company needs full export approval from the Department of Energy. It also needs an environmental review and approval from FERC. The company says the facility would be able to export 14 million metric tons of LNG a year. G2 LNG, which formed in June 2014, hopes to get federal approval and begin construction by mid-2017. G2 LNG joins a couple dozen companies proposing U.S. LNG export projects on all three coasts. ***P&GJ***

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Senate Hears Criticism over Inadequacy of Upcoming Gas Transmission Proposal

INGAA CEO Don Santa showed increasing frustration with PHMSA's continued failure to move forward with important pipeline safety regulations.

At Senate hearings Sept. 29, he said gas transmission pipelines are hesitant to make extensive safety investments now since those investments could be proved inadequate or wrong-headed once PHMSA finally publishes an upcoming safety rule containing numerous changes dictated by the 2011 *Pipeline Safety, Regulatory Certainty, and Job Creation Act*.

The final rule isn't expected for two years, although a proposed rule is apparently imminent. The key components of that proposed rule, according to Santa, will be a presumed expansion of the 2004-vintage integrity management program beyond high-consequence areas and new testing requirements on pipelines built before 1970.

A broad *proposed* rule on those and other issues has apparently been approved by the White House Office of Management and Budget. However, it is a proposed rule, and any changes to pipeline safety programs won't go into effect for a few years, at minimum.

"The practical consequence of this delay, however, is to erode the confidence of some pipeline companies that their voluntary safety commitments will be consistent with the final rules adopted by PHMSA," Santa said.

If the proposed rule on liquid pipeline safety published by PHMSA on Oct. 1 (see item following) is any guideline, the proposed gas transmission rule is likely to impose much tougher federal safety requirements than are currently in force.

Congress could complicate this timing issue further. The House and Senate are considering changes to the 2011 law and pipeline safety laws more broadly. So, theoretically, PHMSA could propose safety changes in response to the 2011 edicts, transmission companies could move integrity programs in that direction before a final rule is proposed, and then Congress could make further changes, necessitating a new PHMSA rulemaking.

The House and Senate have begun to work on a pipeline law reauthorization, albeit slowly. Sen. Debbie Fischer's (R-MI) Surface Transportation and Merchant Marine Infrastructure, Safety and Security Subcommittee held the latest hearing Sept. 29.

At the hearing, Christopher Hunt, chairman of the National Safety Transportation Board, said, "There is clearly significant room for improvement" in PHMSA's rules regulating natural gas pipelines.

Hunt mentioned a study the NTSB published this year called *Integrity Management of Gas Transmission Pipelines in High Consequence Areas*. It found that although PHMSA's gas IM requirements have kept the rate of corrosion failures and material failures of pipe or welds low, no evidence exists to show that the overall occurrence of gas transmission pipeline incidents in HCA pipelines has declined.

PHMSA Proposes Liquid Pipeline Safety Changes

Striking a blow for equal treatment, PHMSA proposed a new rule for liquid pipelines on Oct. 1 just as it was planning to get out the parallel gas transmission rule. The proposal would require liquid pipelines to ramp up their safety programs in several areas, including leak detection and repair of pipeline anomalies. API released a somewhat ambiguous statement in response to the proposed rule.

"Safety is our top priority," said Robin Rorick, API Midstream Group director. "We are always looking for new ways to enhance an already safe industry. "We need a practical pipeline safety rule for hazardous liquids that will complement industry's strong safety standards. We look forward to working with PHMSA when it comes to protecting the public."

In February 2011, after PHMSA issued an advance notice of proposed rulemaking, the API and the Association of Oil Pipe Lines sent a comment that said in part:

"However, to the extent there is any need to modify PHMSA's regulations; we submit there is no support for wholesale changes. API and AOPL also believe that many of the topics being considered in the ANPRM do not warrant the issuance of a formal rulemaking."

The proposed rule seems to anticipate some fairly significant changes. It would modify the integrity management criteria, both by expanding the list of conditions that require immediate remediation and consolidating the timeframes for remediating all other conditions, and apply those same criteria to pipelines that are not subject to the IM requirements, with an adjusted schedule for performing non-immediate repairs.

There would be a new requirement for use of inline inspection tools applied to any pipeline that could affect a high-consequence area; that pipeline would have to be capable of accommodating these devices within 20 years, unless its basic construction won't permit that accommodation.

The proposed rule would improve the quality and frequency of tests used to assess the condition of pipelines and establish stricter repair guidelines for high-risk pipelines. The proposed regulations would modify repair and replacement criteria under PHMSA's risk-based management framework by expanding the list of conditions that require immediate repair, establishing shorter repair timelines for critical repairs, and tightening the standards for pressure tests.

Industry Unhappy with Proposed Rule on Notification

One proposed rule PHMSA issued last summer has already produced a cascade of industry criticism. Also stemming from the 2011 pipeline safety act, it extends current operator qualification (OQ) standards to construction workers on pipeline projects and establishes a specific time limit for telephonic or electronic reporting of pipeline accidents and incidents.

The proposal mandates reporting "not later than one hour following the time of such confirmed discovery." A pipeline would have to revise or confirm that initial notification within 48 hours of confirmed discovery of the accident or incident.

In comments submitted to PHMSA, INGAA asked the agency to limit incident reporting to "confirmed discoveries" as stated in the congressional language in the 2011 act. In the proposed rule the agency appeared to expand the congressional criterion by defining confirmed discovery as one in which "there is sufficient information to determine that a reportable event may have occurred even if an evaluation has not been completed."

Eric J. Amundsen, vice president of Technical Services, Energy Transfer Partners, argued by adding the word "may" the definition contradicts its intent.

"Understanding of plain English usage would not hold that discovery has been confirmed if it is believed that an event may have occurred," he said.

INGAA also contested the definition of a "reportable incident" and said not all of them can be reported in one hour. It suggested PHMSA distinguish between a significant and non-significant event, the latter being one based only on account of property damage estimates in which there is no fatality or injury resulting in hospitalization. ***P&GJ***

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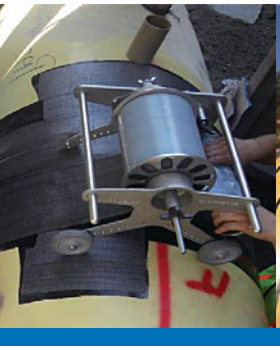



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Atlantic Coast Pipeline to Build $5 Billion Natural Gas System

Four major U.S. companies – Dominion, Duke Energy, Piedmont Natural Gas and AGL Resources – formed Atlantic Coast Pipeline LLC to build a $5 billion interstate natural gas pipeline.

The 564-mile Atlantic Coast Pipeline (ACP) will be capable of delivering up to 1.5 MMcf/d of gas that will be used to generate electricity, heat homes and run local businesses in West Virginia, Virginia and North Carolina.

Construction plans call for 81 miles of pipeline construction in West Virginia, 287 miles in Virginia – including a lateral to Hampton Roads – and 196 miles in North Carolina. When completed, the permanent 75-foot pipeline easement, permanent aboveground facility sites and access roads will total about 5,185 acres.

Pending regulatory approval, construction is expected to begin in the second half of 2016, and the pipeline to be placed in service in late 2018.

Ownership stakes in Atlantic are: Dominion, 45%; Duke Energy, 40%; Piedmont, 10%; and AGL Resources, 5%. Utility subsidiaries and affiliates of all four companies plus PSNC Energy have signed on as customers of the pipeline.

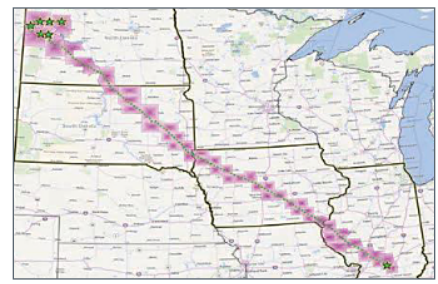
Vallourec to Supply 14,000 Tons of Pipe for Deepwater Project

Vallourec has deliveries totaling 14,000 tons of premium tubes in the scope of a contract with Hess Corp. for the Stampede project in the U.S. Gulf of Mexico. Stampede is a deepwater subsea development located in the Green Canyon Block area, 115 miles south of Fourchon, LA.

Vallourec is providing over 5,000 tons of various sizes of oil country tubular goods (OCTG) for the critical deepwater development wells, including high-performance premium grades from Europe and Ohio. Over the life of the project the majority of the pipes will be threaded at VAM USA, Houston, with VAM®SLIJII™ and VAM® HP™ for a total of over 12,000 premium connections.

Vallourec's contract covers 9,000 tons of seamless steel line pipe for flowlines and steel catenary riser (SCR). They will be installed in water depths of about 3,500 feet.

Michels, Precision Pipeline Awarded Contracts for Dakota Access Pipeline



Dakota Access Pipeline, LLC has awarded Michels Pipeline Construction, a Division of Michels Corporation, and Precision Pipeline, LLC construction contracts for multiple segments along the 1,134-mile Dakota Access Pipeline.

Once completed, the project will transport light sweet crude oil from the Bakken and Three Forks production areas in North Dakota to Patoka, IL where shippers will be able to access multiple markets, including Midwest, East Coast and Gulf Coast regions.

Michels and Precision will each construct pipeline segments in North Dakota, South Dakota and Iowa. Ultimately, Dakota Access will sign construction contracts with up to five union contractors.

As part of the agreement, Brownsville, WI-based Michels Pipeline and Eau Claire, WI-based Precision will use 100% union labor, with half of the workers sourced from local halls in each state the pipeline crosses. In anticipation for the project and 2016 demand, Michels and Precision have made commitments exceeding $200 million to Caterpillar, John Deere and Vermeer for heavy construction and related equipment.

Michels, which has a field office in Cedar Rapids, IA, will construct segments in Iowa, South Dakota and North Dakota, totaling 380 miles. Precision will construct segments in Iowa and Illinois, totaling 476 miles. Collectively, Michels and Precision will employ up to 4,000 people per state. The construction companies yet to be named will construct segments in North Dakota.

Dakota Access expects permit approvals by late 2015 with a projected start of construction in early 2016. The pipeline is expected to be in service by late 2016.

Quanta Services Wins Contract for REX Zone 3 Project

Rockies Express Pipeline LLC (REX) has selected Quanta Services to provide turnkey engineering, procurement and construction services for the REX Zone Three Capacity Enhancement Project. Quanta subsidiaries QPS Engineering and Price Gregory International will play key roles in the project, which includes installing three new compressor stations and upgrading of two existing stations.

As the only domestic pipeline that links the Rocky Mountain and Appalachian supply basins to the Midwest and Gulf Coast markets, REX is an important outlet for producers moving natural gas from the Rockies and Utica/Marcellus shale plays to these major consumer markets which serve millions of natural gas consumers.

Quanta has begun engineering and other frontend services for the project, with construction expected to begin in the second quarter of 2016 or when REX receives the required regulatory approvals. Subject to obtaining these approvals, completion is expected in late 2016.

Once the project is complete, the new and upgraded facilities are expected to create up to 800,000 Dth/d of additional natural gas takeaway capacity from the Appalachian Basin to Midwestern and other high-demand natural gas markets.

FERC Approves Cameron Access Project

Columbia Pipeline Group, Inc. and Columbia Pipeline Partners LP won Federal Energy Regulatory Commission approval to construct the Cameron Access Project in southwest Louisiana by its subsidiary Columbia Gulf Transmission, LLC.

The project includes improvements to Columbia Gulf's existing pipeline system as well as ancillary facilities, a new compressor station near Lake Arthur, LA and the installation of a 26-mile greenfield pipeline lateral in Cameron Parish that provides direct access to the Cameron LNG export facility.

The project involves investment of

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$310 million and includes binding precedent agreements for over 90% of the 800 MMcf of new firm transportation capacity. Construction is anticipated next spring, and the project placed into service in early 2018.

Shell Announces Deepwater Development in Gulf

Shell made the final investment decision to advance the Appomattox deepwater development in the Gulf of Mexico. The decision authorizes construction and installation of Shell's eighth and largest floating platform in the Gulf.

The development will initially produce from the Appomattox and Vicksburg fields, with average peak production estimated to reach 175,000 boe/d. The platform and the Appomattox and Vicksburg fields will be owned by Shell (79%) and Nexen Petroleum Offshore U.S.A. Inc. (21%). Startup is expected around the end of the decade.

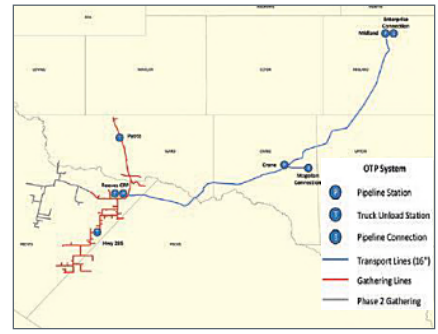
Revamped Route Coastal GasLink Pipeline Project Announced

Coastal GasLink Pipeline Ltd., a wholly owned subsidiary of TransCanada PipeLines Limited that plans to develop the 670-km Coastal GasLink Pipeline, is looking to apply for an alternate route in the Morice River area. It will do so by amending its Environmental Assessment Certificate (EAC) received from the BC Environmental Assessment Office (EAO), and its BC Oil and Gas Commission (OGC) permit.

The proposed alternate route is located in the Regional District of Bulkley-Nechako. It begins at a point 35 km south of Houston and runs westward, parallel to the EAC route. Most of the alternate route is on the north side of the Morice River rather than south side. It rejoins the EAC route 56 km from its starting point.

Coastal GasLink Pipeline officials said they expect to file an application to amend the EAC with the EAO very shortly.

Construction Begins on Pipeline to Serve Delaware Basin



Southern Delaware Oil Gathering and Transport LLC, a subsidiary of Oryx Midstream Services LLC, concluded a binding open season Oct. 29 to obtain volume commitments and acreage dedications to support development of the Oryx Trans Permian pipeline system (OTP).

The OTP system, a crude oil gathering and transportation system to serve the liquids-rich southern Delaware Basin in Texas, is supported by five anchor shippers that collectively will dedicate 220,000 operated acres with an area of mutual interest covering over 1 million acres.

Spanning portions of Reeves, Ward, Pecos, Crane, Upton and Midland counties, the OTP system will have an initial capacity of 160,000 bpd with the capability to be expanded to up to 220,000 bpd, based on customer demand.

To support volumes for the current anchor shippers, the system is expected to include over 300 miles of gathering pipeline, 100 miles of 16-inch transmission pipeline and three storage terminals with 300,000 bbls of leased or owned working storage capacity. The terminals will be located near the Texas towns of Pecos, Crane and Midland. The OTP system will provide access to two major interconnects with delivery into Magellan's Longhorn Pipeline.

Now under construction, the OTP system will be completed in two phases: the first phase with service to Crane is expected to be operational by early 2016, and the second phase with service to Midland expected to be operational by the second quarter of 2016.

Kinder Morgan Extending Open Season for Utica Marcellus Texas Pipeline

Kinder Morgan, Inc. plans to extend its binding open season to review shipper comments and interest received to date, as well as continue to seek commitments for the proposed Utica Marcellus Texas Pipeline (UMTP) project.

The UMPT would transport natural gas liquids and condensate produced from the Utica and Marcellus basins to delivery points along the Texas Gulf Coast, including connectivity to a Kinder Morgan dock located along the Houston Ship Channel. The binding open season is scheduled to end Dec. 15.

The proposed project would involve the abandonment and conversion of 964 miles of natural gas service on KMI's existing Tennessee Gas Pipeline, construction of 200 miles of pipeline from Louisiana to Texas, storage in Ohio and 120 miles of laterals to provide basin connectivity.

The $4 billion UMTP will be designed to transport propane, butanes, natural gasoline, y-grade and condensate in batches along the system, with a maximum design capacity of 430,000 bpd. Subject to shipper commitments and regulatory approvals, the pipeline will be in service by late 2018.

JV to Build NGL Processing Plant, Pipelines

Two Houston-based oil and gas companies have formed a $240 million joint venture to build a NGL processing plant and pipelines in La Salle County, TX on the western edge of the Eagle Ford Shale.

The joint venture will be a 50-50 split between the two companies. Targa, which specializes in the storage, processing and transportation of natural gas and natural gas liquids, will contribute $125 million through its master limited partnership, Targa Resources Partners LP. Sanchez, the exploration and production arm of Sanchez Oil & Gas Co., which focuses on the Eagle Ford, will add $115 million.

The plant, which will service Sanchez' Catarina field in the Eagle Ford, will have initial capacity 200 MMcf/d, but could eventually rise to 260 MMcf/d. The project will include 45 miles of pipelines to connect to the gas-gathering system Sanchez already operates in the region.

Targa Resources Partners will operate the plant and the pipelines. For the first five years of the project, Sanchez Energy will contribute 125 MMcf/d of production, but expects that amount to grow. All of Sanchez Energy's natural gas production from the Catarina field will end up in Targa's plant, which the two companies expect to be operational by 2017. ***P&GJ***

WORLDNEWS

Itchthys LNG Central Processing Facility Launched

INPEX Corp. (INPEX) announced that the INPEX-operated Ichthys LNG project launched its central processing facility (CPF) on Sept. 19 from the offshore floating dock at the Samsung Heavy Industries shipyard in Geoje, South Korea, where it is being constructed

Noting that the operation was completed in just two days, Managing Director of Ichthys LNG project Louis Bon said, "The CPF is now berthed quayside at the shipyard where work is continuing to lift and install the living quarters and integrate and commission all equipment in preparation for the CPF's sail away."

The project involves liquefying natural gas lifted from the Ichthys gas-condensate field offshore Western Australia at an onshore gas liquefaction plant constructed in Darwin, Northern Territory, and producing and shipping 8.9 mtpa of LNG and 1.6 mtpa of LPG, along with 100,000 bpd of condensate at peak

The CPF will be towed 5,600 km to the Ichthys Field in the Browse Basin where it will be permanently moored for the life of the project – over 40 years.

Subsea Gas Compression Facility Begins Operation

Statoil has begun production of the world's first subsea gas compression facility at the Åsgard field in the Norwegian Sea. The facility features two MAN Diesel & Turbo HOFIM™ motor-compressor units which were supplied to Statoil's contractor Aker Solutions. It consists of modules for two identical sets of compressors, pumps, scrubbers and coolers fitted together in a 1,800-metric ton steel frame.

While the natural pressure of the reservoir is declining, MAN's motor-compressor units help to extend the reservoirs' productive life on the Åsgard field for another 15 years. Overall, 306 MMbbls of oil equivalent will be added. While the first compressor train started production, the second train is under commissioning.

Gas Processing Capacity Expansion Led by U.S. and Middle East

Global gas-processing capacity is projected to increase from 458 Bcf/d in 2015 to almost 516 Bcf/d by 2019, driven by a full slate of projects in the Middle East, North America and Asia, according to research and consulting firm GlobalData.

The company reports that increasing domestic demand and opportunities for exports are driving gas-processing construction plans in the Middle East and North America. The two regions combined account for over half of the planned global gas processing capacity growth and capital expenditure (capex) through 2019.

Matthew Jurecky, GlobalData's head of Oil & Gas Research and Consulting, noted, "There is broad growth across Asia, but leading gas-processing expansion plans are fractionation in the U.S., and dehydration and sweetening in Iran and the rest of the Middle East."

The report highlights that some of the largest planned gas-processing plants slated to come online are located in the Middle East, including the Kish terminal in Iran and the Wasit terminal in Saudi Arabia, with capacities of around 3 Bcf/d each.

Jurecky said, "The Middle East has the most gas-processing capacity growth with the highest spending in the world over the next five years. About $32 billion is expected to be spent on the proposed projects to increase capacity to 17.9 Bcf/d. Driven by unconventional production, there is an estimated $27 billion between the U.S. and Canada to increase processing capacity by 15.9 Bcf/d across over 100 plants."

BW Group to Provide LNG Regasification Services in Egypt

The BW Group was selected by the Egyptian Natural Gas Holding Co. (EGAS) to provide LNG regasification services utilizing a Floating Storage and Regasification Unit (FSRU) in Ain Sokhna, Egypt. The project requires a fast track schedule – five months from project inception to first gas – which represents a record short time for implementation.

BW's state-of-the-art FSRU *BW Singapore*, built at Samsung Heavy Industries in South Korea, will be utilized for the project. The FSRU offers a low environmental footprint, high efficiency, storage capacity in excess of 6 MMcf and a peak regasification capacity of 750 MMcf/d.

Ghana's First Lady Names FPSO for Ten Oilfields

The First Lady of the Republic of Ghana, Dr. Nana Lordina Mahama, officially named Ghana's second floating production, storage and offloading (FPSO) vessel at a ceremony in Singapore. The First Lady named the vessel FPSO *Prof. John Evans Atta Mills* after the late president who oversaw first oil from Ghana's Jubilee Field in 2010.

The FPSO will produce and store oil from Ghana's Tweneboa -Enyenra - Ntomme (TEN) oilfields located about 60-km off the coast of the Western Region.

The vessel is nearing the end of its construction at Sembcorp Marine Shipyard in Singapore and is due to sail for Ghana around year end. It is expected to arrive in Ghanaian waters in February to be hooked up to the subsea production equipment which is being installed on the seabed in the TEN fields. The FPSO will start producing oil in mid-2016.

The development of the TEN fields is being led by Tullow Oil along with its partners the Ghana National Petroleum Corp., Anadarko Petroleum Corp., Kosmos Energy and Petro SA.

Esso Australia Resources to Replace 187-km Pipeline

ExxonMobil Australia's subsidiary, Esso Australia Resources Pty Ltd, will replace a 187-km pipeline to transport crude oil and condensate between its Longford and Long Island Point facilities in Victoria.

The pipeline will allow the continued delivery of crude oil and condensate and ensure that natural gas from offshore Gippsland operations continues to flow to Australia households and businesses.

The pipeline replacement has received full project funding from Esso Australia Resources and Gippsland Basin Joint Venture partner BHP Billiton. Each has a 50% interest in the project, with Esso Australia Resources acting as the operator. Pending regulatory approval, the construction of the replacement pipeline is expected to begin later this year.***P&GJ***

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Oil Market Uncertainties, Growing Natural Gas Production in 2016

By **Rita Tubb** and **Michael Reed**, P&GJ Staff Editors

Pipeline & Gas Journal's 35th Annual 500 Report is the industry's most comprehensive listing of U.S. energy pipeline systems. As in past years, the report ranks gas distribution, liquids and gas transmission systems. Gas transmission companies are listed by total miles of pipe. Gas distribution operators by number of customers and liquids pipelines by total crude oil and products delivered.

Additional statistic data compiled for the report are based on operating revenue, gas sold, total throughput of natural gas, product deliveries and miles of mains and service lines. About 95% of the data is based on information from calendar year 2014, compiled through direct company contacts and statistics collected at the Federal Energy Regulatory Commission (FERC).

Though every effort is made to ensure that each company's information is shown correctly, some companies are no longer required to provide statistical data to FERC and did not respond to our inquiries. As a result, some of the data is based on the latest figures available. In the event your company information is incorrect, let us know. We also need to know of any change of address, contact information, mergers and acquisitions.

Energy Trends

The federal Energy Information Administration's *Short-Term Energy and Winter Fuels Outlook (STEO)* released Oct. 6 warns that the oil market faces many uncertainties heading into 2016.

As a result, EIA projects the Brent crude oil price will average $54/b in 2015, $59/b in 2016, unchanged from September's *STEO*. West Texas Intermediate (WTI) crude prices average $4/b lower than Brent in 2015, $5/b lower in 2016.

The report noted oil prices, particularly in the second quarter of 2015, were high enough to support continued development drilling in the core areas within the Bakken, Eagle Ford, Niobrara and Permian formations while WTI prices below $60/b through the forecast period are expected to limit onshore drilling activity and well-completion totals, despite continued increases in rig/well productivity and falling drilling/completion costs.

On natural gas pricing, the STEO shows the Henry Hub spot price averaged $2.66/MMBtu in September, a decrease of 11 cents/MMBtu from the August price. Monthly average Henry Hub spot prices are forecast to remain lower than $3/MMBtu through January, and lower than $3.50/MMBtu through the rest of the forecast. The projected Henry Hub price averages $2.81/MMBtu in 2015 and $3.05/MMBtu in 2016.

Natural gas futures contracts for January 2016 delivery traded during the five-day period ending Oct. 1 averaged $2.87/MMBtu. Current options and futures prices imply market participants place the lower and upper bounds for the 95% confidence interval for January 2016 contracts at $1.93/MMBtu and $4.27/MMBtu. At this time in 2014, the natural gas futures contract for January 2015 delivery averaged $4.19/MMBtu, and the corresponding lower and upper limits of the 95% confidence interval were $2.96/MMBtu and $5.94/MMBtu.

The forecast showed marketed natural gas production will rise by 4.2 Bcf/d (5.6%) and by 1.5 Bcf/d (1.9%) in 2015-16, respectively, with increases in the Lower 48 expected to more than offset continuing production declines in the Gulf of Mexico.

Moreover, increases in domestic natural gas production are expected to reduce demand for imports from Canada and to support growth in exports to Mexico.

Survey Results

Liquids' Top 10. Overall, not much has changed in the past year. All 10 liquids pipeline companies in terms of crude oil deliveries were in the Top 10 in 2014. Only the rankings changed. Enterprise Crude Pipeline moved from the second spot to claim first place with 959,130 bbls; Plains Pipeline moved from first to second place, reporting 905,310 bbls; and Enbridge Energy was third with 767,589 bbls.

Sunoco Pipeline moved from sixth to fourth place, reporting 526,855 bbls. Seaway Crude Pipeline retained fifth place with 398,237 bbls, and ExxonMobil Pipeline fell from fourth last year to sixth this year, reporting 395,351 bbls. Companies in the seventh through tenth positons retained their rankings from last year. The four rankings were claimed by: Marathon Pipeline, 380,145 bbls; LOCAP, 365,834 bbls; Shell Pipeline, 238,475 bbls; and Phillips 66 Pipeline, 212,983, bbls.

Distribution's Top 10. No changes occurred in the 2015 ranking among LDCs in terms of total gas customers. All kept their respective spots, starting with Southern California Gas in first place with 5,900,000 customers. The next nine were AGL Resources, reporting 4,496,901; by Pacific Gas and Electric, 4,300,000; National Grid, 3,521,687; CenterPoint Energy Operations, 3,373,814; Atmos Energy, 3,042,931; ONE Gas Inc., 2,127,000; Southwest Gas Corp., 1,930,000; Excel Energy, 1,900,00; and Public Service Electric & Gas/Gas Delivery, 1,797,632.

Gas Transmission's Top 10. Little change is found among gas transmission companies in terms of transmission pipeline mileage. Norther Natural Gas claimed the first position, reporting 14,781 miles followed by Tennessee Gas Pipeline with 11,917. The third through tenth places were claimed by: El Paso Natural Gas, 10,222; Columbia Gas Transmission, 9,641; Texas Eastern Transmission, 9,592; Transcontinental Gas Pipe Line, 9,216; Natural Gas Pipeline Company of America, 9,122, ANR Pipeline, 8,882; Southern Natural Gas, 7,033; and Gulf South Pipeline, 6,540. ***P&GJ***

Note: *The 2014 figures used in the report reflect the last full year of data available.*

P&GJ's

Liquids Pipelines In Crude Oil Deliveries

Name of Co.	2014 Crude Oil Deliveries (000) Bbl
1) Enterprise Crude Pipeline	959,130
2) Plains Pipeline	905,310
3) Enbridge Energy	767,589
4) Sunoco Pipeline	526,855
5) Seaway Crude Pipeline	398,237
6) Exxon/Mobil Pipeline	395,351
7) Marathon Pipe Line	380,145
8) LOCAP	365,834
9) Shell Pipeline Company	238,475
10) Phillips 66 Pipeline	212,983

Liquids Pipelines In Operating Revenues

Name of Co.	2014 Operating Revenues ($000)
1) Enbridge Energy	1,596,912
2) Colonial Pipeline	1,171,694
3) TransCanada Keystone Pipeline	1,095,777
4) Magellan Pipeline	967,379
5) Plains Pipeline	780,260
6) Enterprise Crude Pipeline	625,984
7) Mid-America Pipeline	557,818
8) Sunoco Pipeline	555,498
9) ConocoPhillips Transportation Alaska	517,235
10) BP Pipeline (Alaska)	438,110

Liquids Pipelines In Miles of Pipelines

Name of Co.	2014 Miles of Piping
1) Magellan Pipeline	10,415
2) Mid-America Pipeline	8,068
3) Plains Pipeline	7,830
4) Sunoco Pipeline	5,676
5) Colonial Pipeline	5,586
6) Phillips 66 Pipeline	5,137
7) Exxon/Mobil Pipeline	4,958
8) Enterprise TE Products Pipeline	4,668
9) Enterprise Crude Pipeline	4,661
10) Enbridge Energy Ltd. Partnership	4,486

Transmission Pipelines In Operating Revenues

Name of Co.	2014 Operating Revenues ($000)
1) Consumers Energy	2,363,000
2) Duke Energy Ohio	2,036,787
3) Kinder Morgan Texas Pipeline	1,543,805
4) Transcontinental Gas Pipe Line	1,413,206
5) Tennessee Gas Pipeline	1,192,621
6) Texas Eastern Transmission	1,165,248
7) Columbia Gas Transmission	1,116,715
8) Dominion Transmission	1,042,755
9) Northern Indiana Public Service	861,003
10) Rockies Express Pipeline	805,484

Transmission Pipelines In Gas Throughput

Name of Co.	2014 GasThroughput Dth/y (000)
1) Transcontinental Gas Pipe Line	4,987,869
2) Columbia Gas Transmission	4,184,290
3) Tennessee Gas Pipeline	3,327,572
4) Texas Eastern Transmission	2,743,869
5) ANR Pipeline	2,445,999
6) Dominion Transmission	2,018,614
7) Gulf South Pipeline	1,822,042
8) Columbia Gulf Transmission	1,577,585
9) El Paso Natural Gas	1,485,006
10) Northern Natural Gas	1,244,967

Liquids Pipelines In Products Deliveries

Name of Co.	2014 Products Deliveries (000) Bbl
1) Colonial Pipeline	975,300
2) Magellan Pipeline	485,474
3) SFPP	395,627
4) Buckeye Pipe Line	338,194
5) Exxon/Mobil Pipeline	311,955
6) Mid-America Pipeline	282,171
7) Enterprise TE Products Pipeline	281,165
8) Marathon Pipe Line	275,808
9) Plantation Pipe Line	229,801
10) Explorer Pipeline	221,802

Transmission Pipelines In Miles Of Transmission Pipelines

Name of Co.	2014Miles Of Piping
1) Northern Natural Gas	14,781
2) Tennessee Gas Pipeline	11,917
3) El Paso Natural Gas	10,222
4) Columbia Gas Transmission	9,641
5) Texas Eastern Transmission	9,592
6) Transcontinental Gas Pipe Line	9,216
7) Natural Gas Pipeline Co. of America	9,122
8) ANR Pipeline	8,882
9) Southern Natural Gas	7,033
10) Gulf South Pipeline	6,540

P&GJ's 35TH Annual

500

REPORT:

TOP TEN

Note: *The 2014 figures used in the report reflect the last full year of data available.*

Distribution Pipelines In Miles of Piping

Name of Co.	2014 Miles of Distribution Piping
1) CenterPoint Energy Operations	118,188
2) Southern California Gas	98,000
3) AGL Resources	72,928
4) Black Hills Energy	67,138
5) National Grid	64,108
6) ONE Gas	60,800
7) MichCon	50,865
8) Pacific Gas & Electric	48,579
9) Piedmont Natural Gas	42,784
10) Dominion Resources	32,800

Distribution Pipelines In Gas Sold

Name of Co.	2014 Gas Sales, MMcf
1) National Grid	381,571
2) Atmos Energy	291,764
3) Southern California Gas	287,000
4) Public Service Co. of Colorado	247,571
5) Pacific Gas & Electric	228,443
6) Integrys Energy Group	227,240
7) Laclede Gas Co.	200,192
8) Public Service Electric & Gas/Gas Delivery	198,452
9) ONE Gas	166,346
10) TECO Peoples Gas System	161,823

Distribution Pipelines In Operating Revenues

Name of Co.	2014 Operating Revenues ($000)
1) National Grid	5,276,746
2) Atmos Energy	4,940,916
3) Integrys Energy Group	4,144,200
4) Southern California Gas	3,855,000
5) AGL Resources	3,802,000
6) Pacific Gas & Electric Co.	3,432,000
7) CenterPoint Energy Operations	3,301,000
8) Consumers Energy	2,355,527
9) Xcel Energy	2,142,738
10) Consolidated Edison of New York	1,933,000

LEADING GAS DISTRIBUTION UTILITIES

Pipeline & Gas Journal's Annual 500 Report

2014 Rank	Name of Co.	Number of Customers	2014 Sales MMcf	2014 Financial Operating Revenues $(000)	2014 Financial Operating Income $(000)	2014 Additions To Plant $(000)	Miles of Mains	Miles of Service
1	Southern California Gas Co.	5,900,000	287,000	3,855,000	521,000	1,104,000	50,000	48,000
2	AGL Resources	4,496,901	80,729	3,802,000	573,000	441,108		
3	Pacific Gas & Electric Co.	4,300,000	228,443	3,432,000	245,200		6,438	42,141
4	National Grid	3,521,687	381,571	5,276,746	588,878		34,960	29,148
5	CenterPoint Energy Operations	3,373,814	0	3,301,000	287,000	0	73,000	45,188
6	Atmos Energy Corp.	3,042,931	291,764	4,940,916	611,349	529,476	67,146	18,407
7	ONE Gas Inc.	2,127,000	166,346	826,957	225,294	297,103	42,500	18,300
8	Southwest Gas Corp.	1,930,000	39,769	1,382,087	241,603	350,000	30,375	22,383
9	Xcel Energy	1,900,000	0	2,142,738	0	0	34,091	2,394
10	Public Svc. Electric & Gas/Gas Delivery	1,797,632	198,452	1,018,000	172,000	292	17,713	
11	Consumers Energy Co.	1,722,231	0	2,355,527	251,399	484,691	28,854	0
12	Integrys Energy Group	1,698,000	227,240	4,144,200	218,800	377,700	22,500	15,180
13	Laclede Gas Co.	1,500,000	200,192	1,462,600	162,900	0	0	0
14	Columbia Gas of Ohio Inc.	1,423,446	18,201	671,173	105,039	514,276	19,877	0
15	Public Service Co. of Colorado	1,347,459	247,571	1,215,324	111,236	463,087	24,102	0
16	Dominion Resources	1,308,541	30,860	1,898,000	111,594	2,911	21,900	10,900
17	DTE Energy Co.	1,220,791	135,000	1,603,000	290,000	223		
18	MichCon	1,212,581	119,550	1,634,030	109,000	175,000	31,208	19,657
19	Dominion East Ohio Gas Co.	1,191,380	18,024	723,837	167,721		21,600	11,424

Note: *The 2014 figures used in the report reflect the last full year of data available.*

2014 Rank	Name of Co.	Number of Customers	2014 Sales MMcf	2014 Financial Operating Revenues $(000)	2014 Financial Operating Income $(000)	2014 Additions To Plant $(000)	Miles of Mains	Miles of Service
20	Consolidated Edison of New York, Inc.	1,166,574	0	1,933,000		0	4,307	3,055
21	Washington Gas Light Company	1,094,109	69,176	1,416,951	183,700	0	12,713	565
22	WE Energies	1,091,412	139,000	1,496,100	119,342	254,575	21,385	11,347
23	Piedmont Natural Gas Co.	1,009,119	151,146	1,469,988	144,194		22,250	20,534
24	Vectren Corp.	995,000	0	944,600	0	0	16,300	0
25	Questar Gas	962,200	0	0	109,500	0	28,239	
26	Ameren	928,000	98,900	1,140,000	94,200	128,500	21,580	14,548
27	San Diego Gas & Electric Co.	900,000	82,000	547,000	55,000	85,000	9,000	6,000
28	Northern Indiana Public Service Co.	807,211	93,495	63,399	106,173	89,581	17,688	16,191
29	Puget Sound Energy	770,000	0	0	0		12,208	0
30	MidAmerican Energy Company	726,000			0	0	12,927	9,867
31	Northwest Natural Gas Co.	704,644	73,130	754,037	58,692	115,930	14,065	0
32	Baltimore Gas & Electric Co.	655,000	0	0	0	0	6,832	6,010
33	UGI Utilities Inc.	619,398	0	0	0	0	12,045	0
34	National Fuel Gas Distribution Corp.	585,726	72,963	829,066	86,263	85,394	14,655	6,131
35	Black Hills Energy	574,467	142,101	627,133	54,051	88,346	2,888	64,250
36	Public Service Co. of North Carolina	521,000	48,000	552,000	55,000	146,000	10,700	0
37	New Mexico Gas Company	513,000	0	0	0	0	12,000	0
38	Philadelphia Gas Works	507,385	78,829	746,613	119,354	45,408	2,860	3,021
39	PECO Energy	506,204	90,042	646,754	0	121,244	6,780	6,149
40	New Jersey Natural Gas Co.	489,050	0	0	0	0	6,716	6,771
41	Semco Energy Company	434,000	72,260	674,007	99,369	64,749	9,025	576
42	Columbia Gas of Pennsylvania	424,422	35,098	328,926	63,629	330,593	7,499	0
43	SourceGas Inc.	424,331	33,792	392,111	53,009	77,695	15,388	6,547
44	Columbus Gas Of Pennsylvania	421,822	32,217	26,127	56,457	176,598	7,473	
45	Alliant Energy	420,000	0	3,350	383	0	9,280	6,570
46	Duke Energy Ohio	418,327	20,981	382,058	59,668	124,744	5,668	4,868
47	South Jersey Gas Co.	366,854	6,437	443,232	77,390	124,611	6,339	6,514
48	TECO Peoples Gas System Inc.	350,000	161,823	393,500	69,800	80,000	11,600	6,700
49	CPS Energy	335,000	0	0	0	0	5,140	
50	Intermountain Gas Company Inc.	328,632	30,784	251,298	17,887	23,507	6,441	5,612
51	Avista Corp.	322,700	31,367	471,173	26,761	27,839	7,650	0
52	Wisconsin Public Service Corp.	319,145	40,372	352,611	32,077	22,037	7,814	5,296
53	Louisville Gas & Electric Co.	318,582	31,130	304,574	24,736	53,043	4,290	1,689
54	Memphis Light, Gas & Water Div.	313,335	33,866	0	0	0	4,836	
55	South Carolina Electric & Gas Co.	307,000	0	0	0	0	0	17,000
56	Rochester Gas & Electric Corp.	303,000	0	0	0	0	0	0
57	Columbia Gas of Massachusetts	301,679	36,669	581,156	23,138	102,346	4,945	3,487
58	Equitable Gas Co.	275,000	0	0	0	0	3,733	739
59	Yankee Gas Services Co.	272,162	31,523	427,071	33,521	39,361	3,213	2,445

LEADING GAS DISTRIBUTION UTILITIES

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60	Citizens Gas & Coke Utility	266,287	32,948	325,673	26,986	16,541	4,070	4,331
61	Northwestern Energy LLC	265,717	30,180	274,849	28,757	12,646	7,300	4,719
62	Montana-Dakota Utilities Co.	262,970	35,981	304,186	17,673	40,833	6,116	3,591
63	New York State Electric & Gas Corp.	256,000	0	0	0	0	4,434	3,219
64	Columbia Gas of Virginia, Inc.	254,661	24,215	156,549	21,539	179,024	5,114	0
65	Jo-Carroll Energy Inc.	233,267	36,281	412,812	21,972	19,746	5,228	3,207
66	Metropolitan Utility District	228,705	32,046		215,139	0	4,836	
67	Mountaineer Gas Co.	226,000	0	0	0	0	4,900	0
68	M.U.D. of Omaha	217,103	32,031	226,901	14,114	32,671	2,761	3,093
69	Clearwater Gas System	201,719	2,266	41,077	7,941	6,241	862	330
70	Colorado Springs Utilities	192,872	23,816	206,182	0	10,212	2,438	2,728
71	Colorado Springs Utilities	192,872	23,383	210,401	0	18,998	2,453	2,770
72	Entergy Corporation (ENOI & EGSI)	188,000	14,342	0	0	0	3,368	2,146
73	Southern Connecticut Gas Co.	177,689	23,414	421,911	17,800	7,876	2,226	0
74	NV Energy	156,122	15,108	134,823	9,893	9,629	1,763	1,461
75	Madison Gas & Electric Co.	149,000	29,548	221,720	19,181	22,104	2,603	2,288
76	Long Beach Gas and Oil Department	146,471	7,726	80,214	21,004	15,334	918	1,021
77	Columbia Gas of Kentucky	134,952	11,273	72,209	12,072	61,460	2,634	0
78	Orange and Rockland Utilities	128,555	0	0	0	0	1,886	0
79	Richmond Public Utilities	108,789	12,758	170,680	16,179	25,366	1,087	0
80	Knoxville Utilities Board	98,480	12,127	119,253	15,643	15,359	2,388	1,704
81	Duke Energy Kentucky	95,591	8,371	89,877	-482	16,914	1,394	1,160
82	CoServ Gas Ltd.	90,196	8,398	72,665	7,861	10,058	1,523	860
83	Mobile Gas Service Corporation	88,965	4,601	87,883	9,518	18,181	2,258	2,110
84	Springfield City Utilities	82,727	14,233	112,455	9,150	6,453	1,310	1,310
85	Central Hudson Gas & Electric Corp.	77,835	11,230	163,571	9,610	26,333	1,229	865
86	Peoples TWP LLC	60,269	21,335	80,832	5,578	9,789	2,709	0
87	Arkansas Oklahoma Gas Corp.	60,000					2,466	0
88	Roanoke Gas Co.	59,988	7,191	73,543	5,582	14,937	1,059	1,160
89	York County Natural Gas Authority	59,937	7,566	67,422	5,357	19,717	1,622	0
90	Mesa, City of	57,212	3,159	38,496	11,590	23,854	1,264	641
91	Middle Tennessee Utility	54,759	7,389				3,617	
92	Corpus Christi Gas Department, City of	54,113		15,708	0	0	1,355	
93	Austell Gas System	53,825	5,300	0	0	0	1,100	1,100
94	New England Gas	53,558	4,056	59,687	2,960	18,213	606	401
95	Florida Public Utilities Co.	52,260	4,168				1,697	806
96	Huntsville Utilities Gas System	49,786	50,048	48,708	6,363	2,984	1,299	0
97	Vermont Gas Systems, Inc.	48,323	10,322	106,052	7,918	24,298	749	37,211
98	Ohio Gas Co.	47,148	0	16,000	2,570	3,433	1,152	1,053
99	Lawrenceville, City of	46,228	4,113	39,439	8,463	0	1,334	695

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100	Pensacola Energy	43,420	3,519	0	0	0	1,695	0
101	Midwest Energy Inc.	42,542	5,538	54,515	4,526	-9,691	2,954	189
102	Northern Indiana Fuel & Light Co. Inc.	40,341	4,450	46,503	406	1,102	968	0
103	Ft. Hill Natural Gas Authority	39,910	5,785	55,074	10,621	5,628	1,730	1,414
104	Las Cruces Gas System, City of	39,122	3,254	0	0	0	661	
105	Zia Natural Gas Co.	37,287	3,410	30,828	2,819	3,572	1,634	469
106	Okaloosa County Gas District	36,909	2,798	37,900	1,653	0	971	817
107	Berkshire Gas Co.	36,000	4,211	64,000	0	0	74	0
108	Cheyenne Light, Fuel and Power	35,494	5,034	37,263	6,886	20,152	804	449
109	Gainesville Regional Utilities	33,780	20,960	0	0	0	772	0
110	Buford, City of	33,530		54,267			317	
111	Columbia Gas of Maryland Inc.	33,127	4,107	24,255	2,699	25,973	655	0
112	Jackson Energy Authority	29,550	3,050	15,226	1,875	1,597	793	0
113	Southeast Alabama Gas District	28,565	10,378	0	0	0	1,551	1,168
114	Tallahassee Municipal Gas System	27,745	2,696	33,774	1,139	811	860	535
115	Duluth Dept. of Water & Gas, City of	25,871	4,696	0	0	0	511	0
116	Clarksville Water & Gas Division	25,053	0	24,751	0	0	892	0
117	Palo Alto Utilities	23,659	0	35,737	9,177	0	210	0
118	Hamilton Municipal Utilities	23,414	32,528	22,943	0	0	275	133
119	Village of Verona	23,137	2,288	0	0	0	5,256	0
120	Great Plains Natural Gas Co.	22,620	5,260	0	0	0	495	360
121	Greenville Utilities Commission	22,554	3,296	35,415	3,167	710	612	437
122	Lancaster County Natural Gas	22,291	1,878	18,959	1,889	3,176	813	608
123	Trussville Utilities Board	22,086	1,658	0	0	0	523	434
124	Charlottesville Public Works, City of	20,141		35,653		0	337	
125	Alexandria Gas Dept., City of	19,819	1,652	9,153	0	0	553	136
126	Greer Public Works, Commission of	19,634		22,690			714	
127	Willmut Gas & Oil Co.	19,263	1,519	24,312	1,032	3,315	740	471
128	North Alabama Gas	18,808	1,714			2,342	756	372
129	Marshall County Gas District	17,764		26,289	0	0	1,030	
130	Greenwood Commission of Pub. Works	17,619	3,673				718	
131	Citizens Gas Fuel Co.	17,500	3,000	0	0	0	458	307
132	Rocky Mount, City of	16,947	2,005	0	0	0	526	307
133	Lake Apopka Natural Gas Dist.	16,676	741	9,367	0	0	662	0
134	Fitchburg Gas & Electric Light Co.	15,893	0	0	0	0	314	171
135	Lancaster Municipal Gas Co.	15,794	2,130	0	0	0	248	0
136	Florence Gas Dept., City of	15,211	2,215	17,696	652	0	545	412
137	Elk River Public Utility Dist.	15,058	2,800	23,118	0	0	747	0
138	Danville Utilities	15,017	3,460	26,115	4,209	2,406	356	232
139	Powell-Clinch Utility District	14,889	1,655	20,901	1,541	1,575	621	0

LEADING GAS DISTRIBUTION UTILITIES

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140	Corning Natural Gas Corp.	14,853	1,818	25,099	2,112	8,557	428	157
141	Terrebonne Parish Utilties	14,752	1,350	9,711	-1,095	1,300	429	80
142	Greater Dickson Gas Authority	14,713	3,403	22,924	2,432	2,211	754	648
143	Midwest Natural Gas Corp.	14,226	1,861	16,626	1,019	1,457	605	363
144	Olive Branch, City of	14,089	1,624	0	0	0	426	
145	Albany Water, Gas & Light Commission	14,000	0	0	0	0	395	458
146	Cedar Falls Utilities	13,805	1,988	13,782	1,004	827	211	149
147	Wilson, City of	13,720	1,432	21,013	4,725	1,037	384	224
148	Decatur Utilities Gas Dept.	13,613	2,978	21,285	1,039	1,027	418	454
149	Northeast Oklahoma Authority	13,301	0	0	0	0	565	202
150	Grey Forest Utilities	13,113	1,130	11,832	4,376	0	364	165
151	Northwest Alabama Gas Dist.	13,109	2,738	19,563	542	0	1,188	1,360
152	West Tennessee Public Utility	12,787	3,016	18,606	848	650	809	472
153	Clinton-Newberry Gas Authority	12,697	0	17,390	0	0	742	256
154	Sevier County Utility Dist.	12,607	1,851	20,575	2,064		647	333
155	Oak Ridge Utility District	12,129	1,321	17,778	3,629	911	436	420
156	Superior Water, Light & Power Co.	12,000	0	0	0	0	263	167
157	Cullman-Jefferson Gas Dept.	11,678		22,077	0	0	835	0
158	Monroe, City of	10,850	3,229	0	0	0	464	266
159	Fremont Dept. of Utilities	10,836	2,176	0	0	0	198	0
160	Leesburg, City of	10,792	542	0	0	0	241	0
161	Cartersville Gas Dept., City of	10,778	3,142	0	0	0	335	280
162	Gallatin Dept. of Public Utilities	10,766	2,330	0	0	0	364	0
163	Hastings Utilities	10,637	2,053	10,608	-1,231	0	179	178
164	Lexington Natural Gas Dept., City of	10,447	1,143	0	0		424	
165	Holyoke Gas & Electric Dept., City of	10,386	1,967				174	
166	Austin Utilities	10,346	2,642	24,056	1,021	526	178	146
167	Sugar Hill, City of	10,290	815	0	0	0	168	0
168	Owatonna Public Utilities	10,185	1,903	15,727	1,231	468	194	0
169	Fairhope Gas Dept.	10,077	505	0	0	0	540	0
170	Smyrna Natural Gas System	10,031	2,804	0	0	0	268	68
171	Rio Grande Nat. Gas Assoc.	9,892	288	11,847	0	0	0	0
172	Citizens Gas Utility District	9,814	0	0	0	0	715	0
173	Watertown Municipal Utilities	9,732	1,549	12,065	1,333	300	236	198
174	Gibson County Utility District	9,722	750	12,700	0	0	584	0
175	Cookeville Gas Department, City of	9,719	7,438	0	0	0	323	216
176	Jointly Owned Nat. Gas	9,649	3,630		0	9	309	111
177	Shelby Utilities Gas Dept.,City of	9,568	2,150	22,030	12,001	0	486	234
178	Sunrise Gas Dept.	9,535	459	0	0	0	184	0
179	Westfield Gas & Electric Light Dept.	9,507	1,368	16,181	1,032	3,199	208	111
180	City of Henderson Kentucky	9,470	3,380	20,375	1,740	162	253	137

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181	La Grange Gas Dept., City of	9,360	2,146	17,156	2,311	71	338	179
182	Dyersburg Municipal Gas System	9,036	0	0	0	0	215	150
183	Lexington Gas System,	8,961	0	5,799			506	
184	Walker Mun. Nat. Gas System	8,740	377	0	0	0	305	81
185	Presque Isle Electric & Gas Co-Op	8,670	5,797	7,262	356	659	610	0
186	Hawkins County Natural Gas District	8,429	0	0	0	0	211	126
187	Elizabethtown, Kentucky, City of	8,420	1,854	12,054			256	148
188	Orangeburg Public Utilities	8,349	1,152	10,526	1,364	1,115	323	98
189	Covington Natural Gas System, City of	8,202	0	14,815	0	0	214	108
190	Norwich Dept. of Public Utilities	8,151		15,602				
191	St. Croix Valley Natural Gas Co.	8,148	1,204	10,765	453	249	213	160
192	Athens Utilites Gas Dept., City of	8,148	801	0	0	0	446	
193	Navajo Tribal Utility Authority	7,718	0	0	0	0	527	0
194	Corinth Gas & Water Dept.	7,711	896	8,282	1,666	2,826	344	
195	Fultondale Gas Dept., City of	7,692	402	0	0	0	207	0
196	Vicksburg Water & Gas Admin.	7,601	0	84,120	0	0	173	151
197	Dalton Utilities	7,556	2,123	20,828	2,209	516	279	164
198	Indiana Natural Gas Corp.	7,545	1,234	8,747	682	0	304	0
199	Chester County Natural Gas Authority	7,468	3,580	0	0	0	590	0
200	Jefferson-Cocke Gas Utility	7,287	2,477				410	
201	Pike Natural Gas Co.	7,200	0	0	0	0	206	30
202	Laurens Commission of Public Works	7,174	780	0	0	0	395	216
203	Toccoa Natural Gas System	7,057	0	0	0	0	492	165
204	Lebanon Gas Department	6,900	1,100	13,000	350	500	230	85
205	Fayetteville Public Utilities	6,883	837	0	0	0	287	204
206	Community Natural Gas Co.	6,765	934	8,534	661	1,483	336	207
207	Fountain Inn Natural Gas	6,664		6,748				
208	Lawrenceburg Utility System	6,402	608	0	0	0	317	121
209	Graysville Municipal Gas System	6,390	318	6,500	5,000	200	156	70
210	Wakefield Municipal Light Dept.	6,342	516	9,365	624	1,606	85	50
211	Paris-Henry County Public Utlity Dist.	6,248		5,501				
212	Union, City of	6,237	1,626	12,520	1,845	0	403	149
213	Athens Utility Board	6,071	786	0	0	0	411	
214	Morton Utilities	6,028	1,290	9,083	0	0	118	93
215	New Ulm Public Utilities Commission	6,016	1,393	0	11,094	0	76	122
216	Savannah Utilities, City of	5,570	396	0	0	0	279	
217	Chambersburg Gas Dept., Borough of	5,565	1,059	0	0	0	0	0
218	Eunice Municipal Gas	5,562	700	0	0	0	105	0
219	Sylacauga Utilities Board	5,445	2,886	13,719	2,145	125		137
220	Canton Municipal Utilities	5,439	929	4,045	-459	27	178	154
221	Hutchinson Utilities Commission	5,408	1,698	14,647	346	531	103	88

LEADING GAS DISTRIBUTION UTILITIES

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222	Brownsville Utility Department	5,355	489	0	0	0	174	98
223	Winfield, City of	5,281	0	0	0	0	93	87
224	Deming Gas System, City of	5,273	0	3,114	0	0	120	93
225	Richmond Utilities	5,164	401	4,205	946	0	91	0
226	City Gas Co.	5,126	75	6,400	6,051	480	260	94
227	Del Rio Gas System, City of	5,005	0	0	0	0	263	63
228	Ripley Gas Department	4,965	0	0	0	0		0
229	Dumas, City of	4,927	4,453	3,592	2,058	0	73	
230	Milton, City of	4,901	0	0	0	0	245	99
231	Booneville Gas, City of	4,882	422	0	0	0	301	0
232	Los Alamos County Utilities	4,787	852				124	
233	Ft. Morgan Municipal Utilities	4,688	0	0	0	0	98	69
234	Southwestern Virginia Gas Co.	4,623	0	0	0	0	149	498
235	Easton Utilities	4,474	530	0	0	0	98	
236	Chanute Municipal Gas	4,449	502	5,602	0	0	89	50
237	EnumcGas Dept., City of	4,422	441	0	0	0	93	
238	Nebraska City Utilities	4,369	727	5,451	879	271	126	67
239	Elberton Natural Gas System	4,300	0	0	0	0	149	12
240	Brenham Municipal Gas Sys., City of	4,251	395	0	0	0	116	0
241	Pryor Municipal Utility Board	4,244	368	2,179	150	75	87	16
242	Loudon Utilities	4,238	3,155	0	0	0	267	
243	Alexander Municipal Gas Co.	4,217	261	3,031	0	0	144	80
244	Trinidad, City of	4,155	635	4,813	-754	0	70	32
245	Bay City Gas Co.	4,138	220	2,663	250	417	196	38
246	Guymon Municipal Gas Co.	4,078	0	0	0	0	79	0
247	Elberton Utilities Natural Gas Div.	4,027	350	0	0	0	185	0
248	Thibodaux Gas System, City of	4,000	261	3,190	118	40	81	54
249	Pascagoula Utilities	3,996	342	0	0	0	184	0
250	Fulton Utilities, City of	3,949	700	0	0	0	112	
251	Kennett Board of Public Wks.	3,948	402	0	0	0	86	
252	Humboldt Utilities	3,904	0	0	0	0	144	60
253	Lower Valley Energy	3,872	783	9,084	1,372	1,629	195	72
254	Robstown Utility Systems	3,871	0	0	0	0	68	0
255	Kentucky Frontier Gas LLC	3,800	378	4,067	400	80	291	42
256	Sheffield Utilities	3,730	249	3,273	341	36	100	105
257	Citizens Westfield	3,700						
258	Hartselle Utilities	3,682	0	0	0	0	52	0
259	Gulf Breeze, City of	3,589	179	0	0	0	144	
260	Salem, City of	3,561	549	0	0	0	0	76
261	Safford, City of	3,516	0	0	0	0	71	45
262	Parsons Natural Gas System	3,440	198	0	0	0	267	0

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263	Poplar Grove UtilityDistrict	3,382	199	0	0	0	177	0
264	Chickasaway Nat. Gas District	3,368	0	0	0	0	210	0
265	Iberville Parish Natural Gas System	3,332	204	4,835	2,107	0	192	0
266	Palatka Gas Authority	3,323	179	2,645	1,563	0	106	78
267	Thomasville Utilities, City of	3,225	465	0	0	0	161	0
268	Perry Natural Gas System	3,184	333	0	0	0	80	0
269	Ft. Valley Utilities Commission	3,151	0	0	0	0	89	0
270	Tuscumbia, City of	3,034	334	2,730	90	113	65	64
271	Circle Pines Utilities	3,022	364	3,511	69	267	53	17
272	Plaquemine City Water & Light	2,994	159	0	0	0	59	0
273	Batesville Gas Utility	2,985	614	2,992	-497	263	81	77
274	Bennettsville Municipal Gas Dept., City of	2,870	101	0	0	0	86	0
275	Hohenwald Gs Dept.	2,704	206	0	0	0	70	0
276	Iola, City of	2,700	0	0	0	0	54	0
277	Fairfield Municipal Utilities	2,685	280	0	0	0	58	
278	Thompson Gas System	2,678	97	0	0	0	97	0
279	Moss Point Municipal Natural Gas	2,614	220	0	0	0	0	0
280	Americus, City of	2,585	592	825	0	0	104	100
281	Sullivan Gas Dept., City of	2,473	293	0	0	0	52	0
282	Tomball Municipal Gas Dept.	2,409	296	0	0	0	66	0
283	Jamestown Gas System	2,257	198	0	0	0	162	0
284	Etowah Utilities	2,195	1,160	0	0	0	105	0
285	Macon Municipal Utilities	2,183	349	2,817	529	0	100	33
286	City of Gonzales	2,124	161	0	0	0	79	
287	Fitzgerald Utilities	2,102	652	0	0	0	54	0
288	Fall City Utilities	2,070	218	0	0	0	36	0
289	Marion Natural Gas System	2,050	327	0	0	0	68	
290	Fulton Municipal Gas System	2,050	150	0	0	0	0	
291	Donaldsonville, City of	2,004	100	0	0	0	0	0
292	Picayune, City of	1,970	117	0	0	0	102	0
293	Hawkinsville Natural Gas, City of	1,903	395	0	0	0	62	
294	Orange City Municipal Utilities	1,887	444	0	0	0	55	0
295	Selmer Utility Dist.	1,734	182	0	0	0	101	
296	Port Allen Muncipal Gas District	1,585	124	0	0	0	55	
297	Senatobia Water & Gas Dept., City of	1,576	398	0	0	0	70	0
298	Wahoo Utilities, City of	1,576	170	0	0	0	0	0
299	Bethany Municipal Gas System	1,532	171	0	0	0	28	0

LEADING TRANSMISSION PIPELINES

Note: *The 2014 figures used in the report reflect the last full year of data available.*

2014 Rank	Name of Co.	Miles of Gas Pipeline Operated Total Miles	Transmission	Gathering	Storage	2014 Gas Throughput Dth/y (000)	2014 Oper. Revenues $(000)	2014 Oper. Income $(000)
1	DCP Midstream	67,913	5,812	62101	0	2,682	14,013	751
2	Northern Natural Gas Co.	14,781	14,781	0	0	1,244,967	749,039	184,183
3	Tennessee Gas Pipeline Co.	11,917	11,917	0	0	3,327,572	1,192,621	458,007
4	El Paso Natural Gas Co.	10,222	10,222	0	0	1,485,006	577,604	191,817
5	Columbia Gas Transmission LLC	9,641	9,641	0	0	4,184,290	1,116,715	213,453
6	Texas Eastern Transmission LP	9,592	9,592	0	0	2,743,869	1,165,248	378,579
7	Natural Gas PL Co. of America	9,395	9,122	5	268	145,181	651,548	103,213
8	Transcontinental Gas Pipe Line Corp.	9,216	9,216	0	0	4,987,869	1,413,206	332,150
9	ANR Pipeline Co.	8,882	8,882	0	0	2,445,999	516,449	60,206
10	Dominion Transmission	7,519	3,616	3373	530	2,018,614	1,042,755	314,003
11	Gulf South Pipeline Co, LP	7,379	6,540	839	33	1,822,042	409,112	104,481
12	Southern Natural Gas Co.	7,042	7,033	9	0	1,093,464	577,037	214,762
13	Pacific Gas & Electric Co.	6,437	6,000	400	37	740	3,621	0
14	Panhandle Eastern Pipe Line Co.	5,998	5,998	0	0	743,285	357,245	78,654
15	Enable Gas Transmission LLC	5,902	5,902	0	0	1,212,292	494,067	106,747
16	Texas Gas Transmission LLC	5,766	5,766		0	50,155	406,562	137,104
17	Southern Star Central Gas PL Inc.	5,654	5,654	0	0	406,522	248,573	63,387
18	Florida Gas Transmission Co. LLC	5,324	5,331	0	0	974,051	795,990	324,852
19	Tallgrass Interstate Gas	4,654	4,654			206,656	111,186	9,883
20	Colorado Interstate Gas Co.	4,225	4,225	0	0	1,001,244	402,881	123,851
21	Northwest Pipeline GP	3,855	3,855	0	0	732,015	470,049	152,421
22	Columbia Gulf Transmission Co.	3,500	3,500	0	0	1,577,585	154,567	35,359
23	Williston Basin Interstate PL Co.	3,452	3,452		141	262,015	92,563	21,131
24	Trunkline Gas Co., LLC	2,923	2,923	2	27	756,944	167,284	49,228
25	Kinder Morgan Texas Pipeline L.L.C.	2,810	2,810	0	0	1,077,861	1,543,805	24,669
26	Transwestern Pipeline Co., LLC	2,596	2,596	0	0	470,783	228,185	93,118
27	National Fuel Gas Supply Corp.	2,567	1,513	623	431	606,320	204,232	68,403
28	Consumers Energy Co.	2,550	2,550	0	0	373,000	2,363,000	113,500
29	ONEOK Gas Transportation L.L.C.	2,497	2,497	0	0	346,371	70,367	18,542
30	Great Lakes Gas Transmission LP	2,115	2,115	0	0	560,093	145,667	49,856
31	Questar Pipeline Co.	1,891	1,891	0	52	454,145	175,184	55,917
32	Kern River Gas Transmission Co.	1,718	1,718	0	0	850,812	354,256	116,001
33	Rockies Express Pipeline LLC	1,712	1,712	0	0	833,215	805,484	300,056
34	Northern Indiana Public Svc. Co.	1,689	1,653	36	0	413,322	861,003	63,399
35	Enable Mississippi River Trans. LLC	1,557	1,557	0	0	340,400	97,684	7,692
36	East Tennessee Natural Gas Co.	1,515	1,515	0	0	292,554	160,406	49,608
37	Carolina Gas Transmission	1,480	1,480	0	0	138,276	64,871	18,552
38	Northern Border Pipeline Co.	1,408	1,408	0	0	996,233	293,318	109,317
39	Gas Transmission Northwest Corp.	1,354	1,354	0	0	718,832	188,170	72,372
40	Algonquin Gas Transmission Co.	1,129	1,129	0	0	730,569	296,548	92,143
41	PostRock KPC Pipelines	1,120	1,021	26	0	11,371	10,255	116

Note: *The 2014 figures used in the report reflect the last full year of data available.*

2014 Rank	Name of Co.	Miles of Gas Pipeline Operated			Storage	2014 Gas Throughput Dth/y (000)	2014 Oper. Revenues $(000)	2014 Oper. Income $(000)
		Total Miles	Transmission	Gathering				
42	Sea Robin Pipeline Co.	1,050	559	437	0	110,634	36,365	7,901
43	KPC Pipeline LLC	1,047	1,021	26		12,756	10,485	441
44	Alliance Pipeline L.P.	922	922	0	0	712,571	293,097	108,129
45	Equitrans, LP	900	900	0	0	722,643	268,052	112,210
46	Paiute Pipeline Co.	860	860	0	0	33,993	33,243	5,158
47	Wyoming Interstate Co.	849	849	0	0	1,022,399	150,343	50,196
48	West Texas Gas Inc.	808			0	41,782	171,255	15,919
49	Gulfstream Natural Gas Sys., LLC	745	745	0	0	422,714	274,711	153,485
50	Ruby Pipeline	683	683			333,316	345,587	155,938
51	Viking Gas Transmission Co.	674	674	0	0	89,747	27,210	3,947
52	Ozark Gas Transmission LLC	526	526			40,932	16,959	1,268
53	MidContinent Express Pipeline	513	513	0	0	875,302	258,338	100,096
54	Questar Southern Trails PL Co.	488	488	0	0	27,700	8,347	2,681
55	Mojave Pipeline Co.	468	468	0	0	132,119	18,703	5,684
56	Eastern Shore Natural Gas Co.	442	442	0	0	43,384	42,235	12,657
57	Trailblazer Pipeline Co.	436	436	0	0	260,587	38,920	7,646
58	Iroquois Gas Transmission Sys. LP	416	416	0	0	545,684	199,900	71,021
59	Cheyenne Plains Gas PL Co. LLC	413	413	0	0	138,847	101,706	43,606
60	American Midstream (Mid-LA) LLC	412	412	0	0	44,373	4,288	-915
61	High Point Gas Transmission LLC	405	405			114,460	23,181	11,428
62	Midwestern Gas Transmission Co.	400	400	0	0	249,685	36,589	12,539
63	Gulf Crossing Pipeline LLC	374	374	0	0	836,133	245,356	58,392
64	Stingray Pipeline Company, L.L.C.	370	370	0	0	46,361	19,403	851
65	Maritimes & Northeast PL LLC	346	346	0		114,230	164,746	72,153
66	Vector Pipeline L.P.	334	334	0	0	541,143	94,690	36,350
67	Transcolorado Gas Transmisson Co.	312	312	0	0	83,900	42,865	10,519
68	Tuscarora Gas Transmission Co.	305	305	0	0	43,574	27,525	10,968
69	Bison Pipeline LLC	302	302			62,946	81,123	28,854
70	American Midstream (Ala-Tenn) LLC	295	295	0	0	16,847	2,354	-1,354
71	Southeast Supply Header LLC	286	286	0	0	350,628	108,400	50,331
72	Destin Pipeline Co. L.L.C.	273	273	0	0	315,055	50,189	850
73	Mogas Pipeline LLC	267		267	0	12,200	13,727	3,928
74	Guardian Pipeline, LLC	262	262	0	0	93,920	67,578	26,145
75	MIGC Inc.	262	262		0	25,096	9,098	1,034
76	Questar Overthrust Pipeline Co.	259	259	0	0	492,058	71,828	30,201
77	Discovery Gas Transmission L.L.C.	258	96	162	0	158,774	12,339	21,788
78	Millennium Pipeline Company LLC	253	253	0	0	971,429	190,414	99,211
79	Empire Pipeline Inc.	250	250	0	0	219,067	81,825	37,146
80	WTG Hugoton L.P.	246	152	94	0	40,103	8,045	590
81	Western Gas Interstate Company	236	236	0	0	5,459	2,296	1,115
82	TC Offshore	232	232			279,892	29,377	-782

LEADING TRANSMISSION PIPELINES

Note: *The 2014 figures used in the report reflect the last full year of data available.*

2014 Rank	Name of Co.	Miles of Gas Pipeline Operated				2014 Gas Throughput Dth/y (000)	2014 Oper. Revenues $(000)	2014 Oper. Income $(000)
		Total Miles	Transmission	Gathering	Storage			
83	Chandeleur PipeLine Company	215	215			15,543	7,269	39
84	Crossroads Pipeline Co.	203	203	0	0	33,668	2,627	70
85	ETC Tiger Pipeline Co. LLC	196	196			341,806	279,299	130,640
86	Mid Continent Market Center	194	194			23,977	7,149	706
87	Elba Express Company LLC	191	191			91,416	89,710	41,268
88	Portland Natural Gas Trans. Sys.	189	189	0	0	60,132	73,620	27,739
89	Fayetteville Express Pipeline LLC	185	185			455,152	167,664	77,557
90	San Diego Gas & Electric	168	168	0	0	121,151	547,399	54,691
91	Sabine Pipe Line LLC	140	140			80,454	5,010	-6,156
92	Dominion Cove Point LNG. LP	136	136	0	0	103,881	296,555	98,576
93	Kinder Morgan (Ilinois) Pipeline LLC	136	136	0	0	6,754	3,292	442
94	Kinder Morgan Louisiana PL LLC	136	136	0	0	3,658	265,334	131,750
95	Venice Gathering System LLC.	125	125	0	0	18,033	6,325	-1,504
96	Dauphin Island Gathering Partners	119	119	0	0	36,826	5,328	-6,338
97	OKTex Pipeline Co. LLC	116	116	0	0	48,214	3,469	1,025
98	Southwest Gas Storage Co.	106	0	0	106	39,769	45,946	14,965
99	Nautilus Pipeline Co., L.L.C.	101	101	0	0	132,352	7,292	3,040
100	Cheniere Creole Trail Pipeline	94	94	0	0	2,652	165	-29,558
101	KO Transmission Company	90	90	0	0	55,636	1,766	548
102	Granite State Gas Trans. Co.	86	86	0	0	17,068	6,041	1,970
103	North Baja Pipeline, LLC	86	86	0	0	118,759	39,267	14,657
104	Golden Pass Pipeline LLC	70	70			9,293	92,606	43,747
105	Big Sandy Pipeline llc	69	69			35,249	41,258	16,708
106	High Island Offshore Sys., L.L.C.	66	66	0	0	26,577	16,365	7,718
107	Sierrita Gas Pipeline LLC	61	61			288	5,952	2,886
108	Midwest Energy Inc.	59	59	0	0	12,271	197,054	26,173
109	Petal Gas Storage LLC	59	59	0	0	212,968	57,207	16,410
110	Centra Pipelines of Minnesota Inc.	58	58	0	0	7,643	1,005	83
111	Garden Banks Gas Pipeline, LLC	50	50	0	0	116,325	12,628	4,167
112	MarkWest Pioneer LLC	50	50	0	0	83,454	10,241	17,534
113	Mississippi Canyon Gas PL Co.	45	45	0	0	72,125	6,877	2,434
114	Central New York Oil & Gas Co. LLC	39	39			248,962	63,386	17,896
115	Hardy Stg. Co. LLC	37	37	0	0	36,036	23,599	11,748
116	Young Gas Storage Co. Ltd.	30	11	4	15	18,258	8,570	6,978
117	Central Kentucky Transmission	29	29	0	0	6,602	190	26
118	Kinetic Energy Express	29	29		0	209,657	71,206	5,936
119	Horizon Pipeline Co. LLC	28	28	0	0	31,530	12,003	4,032
120	Point Arguello Natural Gas PL Co.	27	27	0	0	750	1,967	-1,719
121	Enbridge Offshore PL (UTOS) LLC	25	25	0	0	18,347	1,539	-1,526
122	Hampshire Gas Co.	18	0	0		1,037	5,630	1,020
123	ANR Storage Company	16	16	0	0	79,416	20,593	4,709

Note: *The 2014 figures used in the report reflect the last full year of data available.*

2014 Rank	Name of Co.	Miles of Gas Pipeline Operated			Storage	2014 Gas Throughput Dth/y (000)	2014 Oper. Revenues $(000)	2014 Oper. Income $(000)
		Total Miles Transmission	Gathering					
124	Jackson Prairie Undergrnd Stor. Proj.15	8	7	0	30,428	0	4,070	
125	USG Pipeline	15				2,079	593	594
126	White River Hub LLC	11	11	0	0	482,456	11,064	4,385
127	Gulf States Transmission LLC	10	10	0	0	9,808	614	138
128	Southwest Gas Transmission Co.	9	9	0	0	0	414	169
129	MarkWest New Mexico LLC	8	8			36,489	1,182	341
130	Norgasco Inc.	3	3	0	0	1,643	5,783	1,525
131	Paulsboro Natural Gas Pipeline Co.	3	3			11,621	236	-210
132	Bear Creek Storage Co.	0	0	0	0	69,123	30,345	12,121
133	Cameron Interstate Pipeline	0	0	0	0	-535	7,948	4,468
134	Cimarron River Pipeline LLC	0	0	0	0	24,152	8,796	-1,414
135	Dominion South Pipeline Co.	0	0	0	0	782	259	546
136	Duke Energy Kentucky Inc.	0	0	0	0	22,788	488,724	488,725
137	Energy West Development	0	0	0	0	48	337	148
138	Honeoye Storage Corp.	0	0	0		3,764	3,785	1,023
139	Lake Charles LNG Company, LLC	0	0	0		115	216,246	92,251
140	Lower Valley Energy	0	0	0				
141	NGO Transmission	0	0	0	0	5,077	4,998	792
142	Panther Interstate PL Energy LLC	0	0	0	0	2,385	0	-215
143	Pine Needle LNG	0	0	0	0	12,446	18,011	5,408
144	Saltville Gas Storage Co. LLC	0	0	0	0	20,505	22,039	5,474
145	Southern LNG Co. Inc.	0	0	0	0	109,822	165,780	80,135
146	Steuben Gas Storage Co.	0	0	0	0	4,001	6,251	1,572
147	T.W. Phillips Gas & Oil Co.	0	0	0	0	2,720	2,321	1,233
148	Trunkline LNG Co. LLC	0	0	0	0	115	216,247	92,251
149	Duke Energy Ohio, Inc.					81,303	2,036,787	308,842
150	Elba Express Company LLC		191			91,416	89,710	41,268

LEADING LIQUIDS PIPELINES

Note: *The 2014 figures used in the report reflect the last full year of data available.*

2014 Rank	Name of Co.	Barrels Delivered Out of System In 2014 (000) Total	Crude Oil	Products	2014 Financial Operating Rev ($000)	Income ($000)	Additions to Plant ($000)	Miles of Pipeline Owned/Operated Gathering Lines	Crude Trunk	Products Trunk	Total
1	Colonial Pipeline Co.	975,300	0	975300	1,171,694	575911	-127221	0	0	5586	5586
2	Enterprise Crude Pipeline LLC	959,130	959,130	0	625,984	410579	-305423	0	4661	0	4661
3	Plains Pipeline L.P.	905,310	905,310	0	780,260	332696	-905008	2970	4860	0	7830
4	Enbridge Energy Ltd. Partnership	767,589	767,589	0	1,596,912	677392	-2132166	0	4486	0	4486
5	Exxon/Mobil Pipeline Co.	707,306	395,351	311955	435,243	27913	-53681	485	1969	2504	4958
6	Magellan Pipeline Company, L.P.	696,142	210,668	485474	967,379	328146	-54524	0	1243	9172	10415
7	Sunoco Pipeline L.P.	671,875	526,855	145020	555,498	284240	-1501028	744	2824	2108	
8	Marathon Pipe Line L.L.C.	655,953	380,145	275808	427,317	108125	-80872	0	1661	1381	3042
9	Seaway Crude Pipeline Co. LLC	398,237	398,237	0	387,233	281503	-902072	0	0	0	0
10	SFPP, L.P.	395,627	0	395627	285,474	111220	-53110	0	0	2470	2470
11	Phillips 66 Pipeline LLC	381,485	212,983	168502	365,647	104716	114720	544	2111	2452	5137
12	LOCAP LLC	365,834	365,834	0	42,053	26371	-6174	0	57	0	57
13	Buckeye Pipe Line Co. LP	338,194	0	338194	316,563	137348	-55215	0	0	2778	2778
14	Mid-America Pipeline Co., LLC	282,171	0	282171	557,818	319559	-151502	0	0	8068	
15	Enterprise TE Products PL Co. LLC	281,165	0	281165	432,611	69590	0	0	0	4668	4668
16	Shell Pipeline Company LP	266,184	238,475	27709	254,332	124462	-260164	0	469	45	514
17	NuStar Logistics L.P.	256,053	155,034	101019	268,142	145036	-196267	0	976	2778	3754
18	Phillips 66 Carrier LLC	243,854	104,404	139450	128,031	82102	29012	0	12	926	38
19	Plantation Pipe Line Co.	229,801	0	229801	284,096	86277	-20373	0	0	3123	3123
20	Explorer Pipeline Co.	221,802	0	221802	339,765	147801	45388	0	0	1883	
21	TransCanada Keystone PL L.P.	196,231	196,231	0	1,095,777	664855	-605676	0	1869	0	1869
22	BP Pipelines North America Inc.	192,173	162,649	29524	141,136	-70088	-2737	0	1756	1638	3494
23	Bengal Pipeline Co.,	184,759	0	184759	65,898	39377	-4775	0	0	158	158
24	Zydeco Pipeline Co.	184,463	184,463	0	98,892	66656	-18065	0	446	0	446
25	Mobil Pipe Line Co.	173,220	152,641	20579	40,790	-73563	-11305	94	979	84	1157
26	Citgo Pipeline Co.	170,604	164,890	5714	53,662	47108	-4093	0	128	0	128
27	Centurion Pipeline L.P.	163,908	163,908	0	227,025	88194	-243179	1370	2430	0	3800
28	West Shore Pipeline Company	152,929	36,267	116662	71,056	34748	-23985	0	0	610	610
29	West Shore Pipeline Company	152,529	36,267	116662	71,056	34758	-23985	0	0	610	610
30	Wolverine Pipe Line Co.	143,632	0	143632	94,741	60192	-8563	0	0	628	628
31	West Texas Gulf Pipe Line Co.	136,744	136,744	0	65,182	39460	-1898	0	532	0	532
32	Chevron Pipe Line Co.	135,035	125,576	9459	188,779	-43843	-40497	175	1265	7	1447
33	ONEOK NGL Pipeline LLC	125,712	0	125712	82,597	-76122	-130395	0	0	3231	
34	Minnesota Pipe Line Co., LLC	120,032	120,032	0	192,441	22785	-4559	0	975	0	975
35	North Dakota Pipeline	118,325	118,325	0	258,410	157165	-422282	148	722	0	870
36	North Dakota Pipeline LLC	117,325	117,325	0	258,410	157165		148	727	0	875
37	Mid-Valley Pipeline Co.	110,532	110,532	0	72,715	19687	-13260	0	1043	0	1043
38	Olympic Pipe Line Co.	104,180	0	104180	70,967	18500	-9786	0	0	414	414
39	Valero Partners PAPS LLC	101,217	0	101217	22,405	15202	-1059			24	24
40	Marketlink LLC	99,357	99,357	0	220,916	-99685	-92932	0	0	0	0
41	Platte Pipe Line Company LLC	97,143	87,143	0	146,213	78938	-6897	3	928	0	931

Note: *The 2014 figures used in the report reflect the last full year of data available.*

2014 Rank	Name of Co.	Barrels Delivered Out of System In 2014 (000) Total	Crude Oil	Products	2014 Financial Operating Rev ($000)	Income ($000)	Additions to Plant ($000)	Miles of Pipeline Owned/Operated Gathering Lines	Crude Trunk	Products Trunk	Total
42	West Texas LPG PL Ltd.Partnership	94,946	0	94946	96,653	39444	-5900	0	0	2179	
43	Regency Liquids Pipeline LLC	94,272	0	94272	3,466	2126	-18212	0	0	46	46
44	Bridger Pipeline LLC	87,671	87,671	0	158,049	107135	-119979	975	464	0	1439
45	SouthTex 66 Pipeline Co., Ltd.	87,470	0	87470	118,906	88291	13759	0	0	755	755
46	Valero Partners Lucas LLC	83,025	83,025	0	28,789	19648	-2308	0	17	0	17
47	Phillips Texas Pipeline Co. Ltd.	82,772	56,081	26691	93,521	44916	17104	801	840	514	2155
48	ConocoPhillips Trans. Alaska Inc.	82,509	82,509	0	517,235	227558	-49376	0	819	0	819
49	Kuparuk Transportation Co.	77,938	77,938	0	28,288	13784	-2598	0	37	0	37
50	Lone Star NGL Pipeline L.P.	77,120	0	77120	211,450	146762	-54164	0	0	810	810
51	Seminole Pipeline Co.	76,242	0	76242	87,705	23974	6044	0	0	1248	1248
52	Holly Energy Partners Op. L.P.	75,363	13,886	61477	102,441	67439	-53815	749	238	1534	2535
53	Hardin Street Holdings LLC	72,994	72,994	0	65,967	32102	1149		730		730
54	Enbridge Pipelines Ozark LLC	72,949	72,949	0	63,277	20664	-45967	0	433	0	433
55	Ship Shoal Pipeline Co.	72,938	72,938	0	25,398	6339	5	0	121	0	121
56	Valero MKS Logistics LLC	71,289	52,823	18466	11,596	3785	-646	0	53	20	73
57	Rocky Mountain Pipeline Sys. LLC	69,434	69,434	0	73,555	21149	0	261	1631	0	1892
58	CCPS Transportation LLC	67,798	67,798	0	117,328	33345	-35355	0	581	0	581
59	BP Pipeline (Alaska) Inc.	67,609	67,609	0	438,110	-31000	-78812	0	800	0	800
60	NuStar Pipe Line Op. Partnership L.P.	65,867	0	65867	139,532	54388	-5110	0	0	2342	2342
61	Wood River Pipe Lines LLC	65,437	5,671	59766	46,432	13666	-28597	0	0	1367	1367
62	Sorrento Pipeline Company LLC	64,576	0	64576	38,610	10598	-4970	0	0	716	716
63	Overland Pass Pipeline LLC	57,236	0	57236	92,496	51789	-5948	0	0	1041	1041
64	Hiland Crude LLC	56,268	56,268	0	106,005	41341	0	946	313	0	1259
65	Inland Corporation	55,201	0	55201	34,845	13597	-16384	0	0	352	352
66	TransMountain PL(Puget Snd.) LLC	52,364	52,364	0	19,466	10207	-1281	0	64	0	64
67	Osage Pipe Line Co.	51,890	51,890	0	12,405	6602	-9038	0	135	0	135
68	ONEOK North System LLC	50,684	0	50684	129,873	55829	-9213	0	0	1588	1588
69	Butte Pipe Line Co.	49,382	49,382	0	53,627	22999	-738	0	373		373
70	ONEOK Arbuckle North Pipeline LLC	44,712	0	44712	149,870	5010	-33	0	0	57	57
71	Dixie Pipeline Co.	44,676	0	44676	87,956	30602	-6024	0	0	1320	1320
72	Kinder Morgan Wink Pipeline LP	44,595	44,595	0	47,291	27031	-10869	16	422	0	438
73	EnbridgePipelines (Southern Lights) LLC	44,242	44,242	0	183,870	85066	-15781	0	816	0	816
74	Enbridge Pipelines (Toledo)Inc.	41,962	41,962	0	49,693	18259	-7317	0	88		88
75	Chaparral Pipeline Company	41,238	0	41238	48,519	17420	-8391	0	0	822	822
76	Chicap Pipeline Co.	40,144	40,144	0	15,820	5057	-5606	0	234	0	234
77	Collins Pipeline Co.	38,878	0	38878	11,897	4482	-49	0	0	124	124
78	Calnev Pipeline LLC	38,092	0	38092	51,943	16832	-8823	0	0	562	562
79	Yellowstone Pipe Line Co.	36,724	0	36724	41,211	20958	-18768	0	0	698	698
80	Belle Fourche Pipeline Co.	36,410	35,402	1008	79,856	39675	-59169	2026	835	80	2931
81	Texas Express Pipeline LLC	34,640	0	34640	72,957	32850	-8779	0	0	593	593
82	Mustang Pipeline LLC	32,389	32,389	0	45,730	31385	1677	0	211	0	211
83	Portland Pipe Line Corp.	31,669	31,669	0	14,369	5784	-210	0	166	0	166

LEADING LIQUIDS PIPELINES

Note: *The 2014 figures used in the report reflect the last full year of data available.*

2014 Rank	Name of Co.	Barrels Delivered Out of System In 2014 (000) Total	Crude Oil	Products	2014 Financial Operating Rev ($000)	Income ($000)	Additions to Plant ($000)	Miles of Pipeline Owned/Operated Gathering Lines	Crude Trunk	Products Trunk	Total
84	White Cliffs Pipeline LLC	30,702	30,702	0	160,369	124332	-177546	0	1052	0	1052
85	Coffeeville Resources Crude Trans.	28,658	28,658	0	17,436	0	0	0	0	0	0
86	IMTT Pipelines	28,380	0	28380	2,854	-827	-994	0	0	10	10
87	SALA Gathering Systems	28,306	8,193	19513	22,651	8011	-2780	613	0	0	613
88	MOEM Pipeline LLC	27,543	27,543	0	12,533	7318	119	0	56	0	56
89	SLC Pipeline LLC	27,260	27,260	0	17,854	10390	-63	0	93	0	93
90	EnLink NGL Pipeline L.P.	25,439	0	25439	69,393	37238	-15	0	0	0	0
91	Plains Southcap Inc.	25,040	25,040	0	4,972	1120	0	0	0	0	0
92	Enterprise Lou-Tex NGL Pipeline L.P.	24,996	0	24996	36,732	22165	-256	0	0	281	281
93	DCP Southern Hills Pipeline LLC	24,873	0	24873	94,170	45760	-23190			912	
94	Kenai Pipe Line Co. /Tesoro Corp.	24,827	15,039	9788	6,400	4979	-3900		23		23
95	Tesoro High Plains Pipeline Co.	23,630	23,630	0	61,302	28086	-51438	228	547	0	775
96	Tesaro Logistics Northwest PL LLC	22,102	0	22102	39,586	3605	-4309	0	0	1104	1104
97	Suncor Energy USA Pipeline Co.	21,136	21,136	0	32,005	7076	-46149	0	313	0	313
98	Bakkenlink Pipeline LLC	20,957	20,957	0	29,842	18413	-6056	0	87	0	87
99	Bakkenlink Pipeline LLC	20,957	20,957	0	29,842	18413	-6056	0	87	0	87
100	Cypress Interstate Pipeline Co. LLC	19,834	0	19834	14,206	9995	-24	0	0	104	104
101	Kinder Morgan Oper. L.P. "A"	19,834	0	19834	14,206	9995	-24	0	0	104	104
102	Pioneer Pipe Line Co.	19,714	0	19714	32,248	19827	979	0	0	563	563
103	Genesis Pipeline USA, L.P.	19,232	19,232	0	27,189	9348	-39950	131	245	0	376
104	Kinder Morgan Cochin LLC	19,018	0	19018	71,223	45065	-100047	0	0	1245	1245
105	Delaware Pipeline Company LLC	18,742	0	18742	9,505	6608	-512	0	0	25	25
106	Alpine Transportation Company	18,649	18,649	0	20,111	5910	-759	0	35	0	35
107	Bakken Pipeline Co. L.P.	18,117	18,117	0	30,565	20465	-4000	0	64	0	64
108	Citgo Products Pipeline Co.	16,773		16773	26,742	17477	-952	0	0	344	344
109	Cenex Pipeline LLC	16,621	0	16622	29,561	14318	-9164	0	0	684	684
110	Magnolia Pipeline Co.	15,851	15,851	0	16,119	12770	0	77	0	0	77
111	Front Range Pipeline LLC	15,626	0	15626	28,310	8772	-67945	0	0	449	449
112	PMI Service North America Inc.	15,522	0	15522	28,370	18337	-6161	0	0	47	47
113	Parkway Pipeline LLC	15,199	0	15199	31,296	16136	-8766	0	0	145	
114	Valero Terminaling and Dist. Co.	14,593	873	13720	7,899	3710	-792	0	1	54	55
115	Excel Pipeline LLC	14,366	14,366	0	4,994	3018	0	0	49	0	49
116	Excel Pipeline LLC	14,366	14,366	0	4,994	3018	0	0	49	0	0
117	TriStates NGL Pipeline, LLC.	14,351	0	14351	21,840	6686	-163	0	0	167	
118	Baton Rouge Pipeline LLC	13,946	0	13946	2,525	1198	0	0	0	30	30
119	Mobil Pacific Pipeline Co.	13,634	5,676	7958	3,465	-510	-127	17	0	9	26
120	Red Butte Pipe Line Company	13,585	13,585	0	28,339	6600	-6406	68	736	0	804
121	ONEOK Bakken Pipeline LLC	13,517	0	13517	99,055	61845	-931180	0	0	766	766
122	Frontier Pipeline Company	13,387	13,387	0	12,985	7513	-401	0	290	0	290
123	Black Lake Pipeline Company	12,842	0	12842	12,668	8077	-3322	0	0	313	313
124	Wilprise Pipeline Co. LLC	12,227	0	12227	4,867	2046	-570	0	0	30	30
125	Chisholm Pipeline Co.	12,197	0	12197	6,154	3380	1	0	0	185	185

Note: *The 2014 figures used in the report reflect the last full year of data available.*

2014 Rank	Name of Co.	Barrels Delivered Out of System In 2014 (000) Total	Crude Oil	Products	2014 Financial Operating Rev ($000)	Income ($000)	Additions to Plant ($000)	Miles of Pipeline Owned/Operated Gathering Lines	Crude Trunk	Products Trunk	Total
126	Paline Pipeline Company LLC	11,693	11,693	0	9,589	1115	0	0	186	0	186
127	MarkWest Liberty Ethane PL LLC	11,580	11,580	0	15,170	7144	0	0	33	0	33
128	Hawthorn Oil Trans. (No. Dakota) Inc.	11,292	11,292	0	2,654	1156	-18	0	12	0	12
129	Valero Partners Wynnewood LLC	10,941	0	10941	4,603	3212	-181	0	0	30	30
130	Muskegon Pipeline LLC	10,422	0	10422	7,734	2744	575	0	0	170	170
131	Enbridge Pipelines (Patoka) LLC	10,206	10,206	0	911	359	-1134	0	0	0	
132	Enbridge Pipelines (FSP) LLC	9,487	9,487	0	38,771	11145		0	594	0	594
133	Shamrock Pipeline Corp.	8,664	8,664	0	7,144	3026	-70	135	0	0	
134	GNB NGL Pipeline LLC	8,435	0	9435	4,595	2717	-219	0	0	32	32
135	Tall Grass Pony Express PL LLC	8,370	8,370	0	29,343	5747	-660981	0	699	0	699
136	Buckeye Linden Pipe Line Co., LLC	8,257	8,257	0	2,185	-3492	0	0	0	0	0
137	Belle Rose NGL Pipeline LLC	7,727	0	7727	3,085	1115	0	0	0	48	48
138	Milne Point Pipeline LLC	7,084	7,084	0	9,563	452	-242	0	11	0	11
139	DCP Wattenburg Pipeline LLC	7,081	0	7081	13,238	7016	-187	88	0	356	444
140	Plains LPG Services LP	6,842	0	6842	2,012	-1844	146	0	0	137	137
141	Skelly-Belvieu Pipeline Co. L.L.C.	6,799	0	6799	22,913	9444	-2044	0	0	572	572
142	Jayhawk Pipeline, L.L.C.	6,694	6,694	0	22,548	637	-3897	0	652	0	652
143	WestTex 66 Pipeline Company	6,671	0	6671	8,060	1272	7321	0	0	710	710
144	Buckeye Pipe Line Trans. LLC	6,505	32	66573	46,969	16665	-10117	0	0	1334	1334
145	UNEV Pipeline	6,410	0	6410	28,371	6600	-127	0	0	427	427
146	Heartland Pipeline Company	6,038	0	6038	6,816	767	31	0	0	49	49
147	El Dorado Pipeline Co. LLC	5,927	5,927	0	5,451	3259	-2124	0	28	0	28
148	SP49 Pipeline LLC	5,113	5,113	0	5,991	2379	0	0	31	0	31
149	Hawthorn Oil Trans. (Oklahoma) Inc.	5,109	5,109	0	2,249	893	-20	0	18	0	18
150	Arrowhead Offshore Pipeline LLC	5,002	5,002	0	2,386	1236	-93	0	23	0	23

With a Chill in the Air, Thoughts in New England Turn to Heating Bills

By **Michael Reed, Managing Editor**

As winter approaches, the hot topic of conversation in the Northeast once again becomes the looming frigid temperatures and accompanying burdensome cost of heating homes and offices along with powering manufacturing plants.

With this in mind, the Access Northeast project developers plan to upgrade existing pipeline facilities and market area storage assets in New England to deliver – on peak days – up to 1 Bcf/d of natural gas for electric-generation markets.

The expansion, with potential savings of $1 billion annually to electricity customers in New England, isn't expected to come online until the end of 2018. However, with wholesale electric prices in New England increasing over 175% from December 2014 to February 2015, any sign that additional infrastructure is on the way is welcome news to consumers.

The federal Department of Energy (DOE) reports New Englanders paid almost 21 cents a kilowatt hour in January and average first-quarter household electricity prices that were two-thirds higher than the national average. This inequity became even more apparent with business management consultant ICF International's well-publicized findings that if Access Northeast had been in service during the extreme 2013-14 winter, savings in the region would have totaled $2.5 billion.

"Customers are paying dearly due to pipeline constraints," said Lee Olivier, executive vice president at Eversource Energy. "Infrastructure improvements are needed to solve the region's energy challenges and a scalable solution that will enhance existing pipeline systems has numerous benefits."

Eversource, Spectra Energy – owner of the Algonquin system – and Spectra Energy Partners announced in February that National Grid was joining Access Northeast as a co-developer. That meant Spectra had locked up generating plants serving 70% of the electricity customers in New England.

"This project is different from other expansions that are designed more for local distribution companies or marketers," Richard Kruse, vice president for regulatory and FERC (Federal Energy Regulatory Commission) compliance officer for Spectra, told *P&GJ*. "The primary focus is getting gas to generators currently attached to Algonquin and Maritime pipelines. Most of these generators do not have firm capacity. They mostly rely on capacity release (from LDCs) and that's interruptible."

Richard Kruse

The Access Northeast expansion is designed to maximize direct pipeline interconnects to as many as 60% of ISO New England's power plants, upgrading facilities on the Algonquin system and market area storage capabilities in New England. Located in New York, Connecticut, Rhode Island and Massachusetts (see map), the project will include 125 miles of additional pipeline, with most of the expansion falling within existing corridors.

While the pipeline expansion will be built to handle average year-around loads, adding 550 dekatherms a day (dth/d), there will also be an LNG tank constructed that will allow an additional 440 dth/d to be delivered during winter peak months.

That the tank will be located on land already owned by Eversole should be advantageous when it comes to the permitting process. Another plus for the project is that it takes place primarily in existing right-of-way and involves picking up and laying expanded pipeline capacity rather than building out onto additional land.

"I don't think any pipeliner would say getting permits in today's environment is easy, but it's certainly easier if you are using existing right-of-way," Kruse said.

Access Northwest is in the prefiling stage and while most comments from the public have thus far come from adjacent landowners looking for more specifics, pricing has been a significant issue for local officials. Among the most frequent questions has been, "Who pays for the project?" Answered simply, Kruse said, that process requires electric distributions companies to gain authorizations from various state commissions to collect the cost from customers.

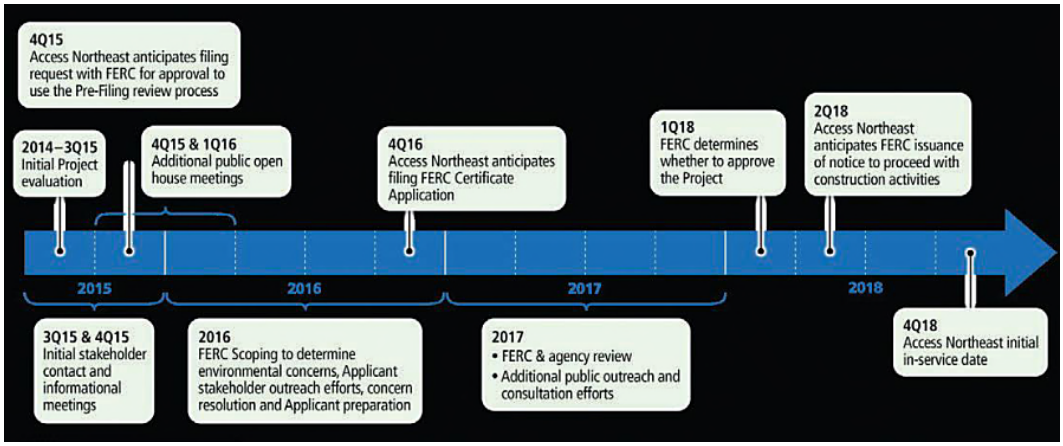
With Massachusetts investigating the ability of its Economic Development Council (EDC) to recover these costs through rates, New Hampshire conducting a similar process and Connecticut preparing to launch a rate stabilization plan (RSP), the region appears to be nearing a consensus.

"The political heat that people have been taking is generating some very positive

developments on the state regulatory and state political front," Kruse said.

The Quandary

In the wake of the shale boom, natural gas has become so inexpensive and plentiful in the United States that many producers are clamoring to export the product. Yet in New England, the lack of pipeline capacity from the Marcellus and Utica shales has found the region importing LNG from as far away as the Middle East.



More and more in recent years, demand for natural gas in New England has been driven by the power-generation sector, which increased its usage share from 15% to 51% in the relatively short time between 2000 and 2011, according to ISO New England data. This occurred during the same period the region grew more dependent on natural gas for heating. In fact, according to the DOE, gas-fired plants supply 44% of New England's electricity, a hefty jump from an 18% share of the market in 2000.

Power-generation companies traditionally don't rely on firm capacity contracts for their supply while LDCs hold most firm capacity to ensure the winter needs of residential and business customers. The crux of the problem becomes obvious: power plant operators want to run at high-load factors during the winter – the same time LDCs are pulling back capacity.

This creates a challenge for an electric industry that needs the gas-fired generators to maintain the reliability of the electricity grid, but claims its operators can't afford the capacity because they aren't paid enough in the electricity market.

At the moment, most power-generation companies rely on capacity acquired either through capacity release from LDCs, which is interruptible and recallable, or they use interconnection points (IP). During the last three or four years, Kruse said, there have

Taking AIM at Relief in 2016

A second major expansion effort in the region for Spectra – expected to come online a couple of years earlier – is its Algonquin Incremental Market (AIM) project. Located in New York, Connecticut, Rhode Island and Massachusetts, the fully owned Spectra venture is expected to be completed in November 2016. In other words, in time to provide relief next winter.

"This is a fairly significant expansion of just shy of 342,000 dth/d, and it's been certificated and is under construction, which will take two years," Richard Kruse, vice president for regulatory and FERC compliance officer for the company, told *P&GJ*.

The AIM Project bolsters the capacity of Spectra's existing Algonquin Gas Transmission system and will allow abundant regional gas supplies from the Appalachian basin to flow into the Northeast.

The project involves expanded pipeline capacity on the Algonquin Gas Transmission system. According to the company, 93% of the project's facilities would fall within or adjacent to existing rights-of-way, while 70% of the facilities would replace pipe within existing rights-of-way.

Algonquin has signed long-term contracts for all of the project's capacity, beginning in November 2016, with 10 shippers – eight southern New England LDCs and two municipal utilities that deliver natural gas to their service areas in Connecticut, Massachusetts and Rhode Island.

Each of the contracts was approved or has been evaluated by each shipper's state regulatory commission or municipal authority process, which determined that the shipper contracts are in the public interest. There are no Maritimes & Northeast Pipeline Company deliveries involved with the AIM Project.

The AIM Project will not be used to transport natural gas for export as LNG. The additional supplies will be used exclusively within southern New England. ■

been very little IP left over.

"That means when it gets really cold they (power generators) lose out on the capacity," he said. "We've been in discussion with the electric distribution companies in New England that are having to flow through the cost of the current structure every winter. When it gets cold the electric rates really fly up, and they have to reflect that in their retail rates. It's quite a challenge for the region to pay the higher energy costs generated due to this lack of assured fuel supply."

Economic Fallout

A recent study commissioned by consumer advocacy group New England Coalition for Affordable Energy pointed to at least five years of additional financial hardships for customers if the region's energy infrastructure isn't expanded.

Conducted by Boston consulting firms La Capra Associates and Economic Development Research Group, the study found the fallout from not acting would lead to hikes in total energy bills between 2016 and 2020 of $5.4 billion. Additionally, it concluded about 167,600 jobs would be lost, along with a drop in disposable income in the region of about $12 billion. The authors said the study's focus was on reviewing infrastructure investment primarily for economic purposes – to reduce prices – rather than investment deemed to be needed solely for reliability purposes.

"The large number of job losses quantified in the study are caused by the combination of higher energy costs and the loss of additional infrastructure investment," said Carl Gustin, spokesman for the coalition. He said higher energy costs alone would cause the region to lose 52,000 private sector jobs by 2020, virtually negating 80% of private-sector job growth projected for that year.

The region has already incurred $7.5 billion in higher energy costs during the past three winters due to the natural gas pipeline system reaching capacity because of demand placed on it for electricity generation and space heating, the study said.

"The positive news is that infrastructure projects have been proposed and some are underway that would mitigate or eliminate these adverse consequences," Gustin said.

Despite this data, not everyone is so sure that more infrastructure, at least in the form of major pipelines and associated buildouts, is the best answer for New England's energy woes.

GDF Suez, which not coincidentally owns a Boston Harbor terminal capable of receiving LNG and an offshore receiving port near Gloucester, MA, argues that imports would offer enough relief without charging electricity customers for additional natural gas pipelines.

A study by research group Skipping Stone and commissioned by GDF Suez to access New England's energy markets found "only modest pipeline improvements" are necessary to create long-term stability to the electricity grid, when LNG supplies and backup oil turbines are placed in use to cover shortfalls.

"Incremental capacity additions to New England's conventional pipeline infrastructure to serve native annual load for LDCs will likely continue to be economic if demand growth occurs, without a large pipeline's detrimental effect of 'crushing' secondary market values and imposing uneconomic load-factor costs on ratepayers," the report said.

While calling the Suez district gas plant, which has been in the region for years, a "vital component of peak-day supply," Kruse expressed reservations about the Skipping Stone study.

"What I would be concerned about would be the capacity of the pipelines to deliver that LNG to power plants on a reliable basis without additional pipeline capacity being constructed," he said. "When LNG was flowed in the past, it had been because on a peak day it was needed and there weren't other supply options."

According to its records, Algonquin has run at almost 100% capacity from the west for the last three years.

"One of the keys things we want to achieve with this project is to be able to tell the region that these power plants will be able to get gas on a firm basis," Kruse said.

Other Voices

Separately, a study by Virginia-based consulting firm ICF International and released by Kinder Morgan, which plans a 188-mile Northeast Expansion Direct (NED) of the Tennessee Gas Pipeline through New Hampshire and western Massachusetts, believes the NED could save New Englanders $3 billion annually.

The report further found if NED had been online during the brutal winter two years ago, savings in the region may have reached $3.7 billion for the year. It also stated the Kinder Morgan pipeline, which will bring an added 1.3 Bcf/d online after its completion in 2018, will reduce costs annually between $2.1-2.8 billion for the following 10 years.

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Morgan company, recently announced the start of its non-binding PowerServe open season, a customized firm service designed to meet the needs of gas-fired generators, specifically in the Northeast and New England.

PowerServe firm service will use assets from the NED project, including regional storage, line pack and legacy TGP facilities. It will offer up to 740,000 dth/d of capacity in the open season. The amount of capacity and specific assets required to provide the no-notice and non-ratable hourly service components of the service will be determined following the close of the open season based on shipper interest.

"The ICF study supports NED's potential contribution to reducing and stabilizing prices, and improving reliability through increased gas availability," said Kimberly S. Watson, president of Kinder Morgan's East Region Gas Pipelines. "New England needs more natural gas capacity, and NED would provide the region with direct access to abundant, reasonably priced supplies of gas. Additional gas supplies will bring down energy costs in New England and benefit consumers who now bear the burden of paying some of the highest energy costs – if not highest – in the country."

A recent New Hampshire PUC staff report was described by Kinder Morgan spokesman Richard Wheatley as "encouraging" in that it points to the possibility of substantial consumer savings brought about by "additional pipeline capacity and the NED project."

On Sept. 27, Kinder Morgan announced TGP reached agreements with producers, local distribution companies (LDCs) and a New York end-use market participant totaling 627,000 dth/d for the supply path component of the proposed NED.

As a result, the company said it will provide a direct supply link from natural gas fields in Pennsylvania to existing and future Northeast and New England markets, and firm transport of incremental supplies for delivery at or near Wright, NY. From the Wright area, shippers can deliver into the market path component of the NED project for transport to Dracut, MA, or into TGP's existing pipeline system, or into the Iroquois Gas Transmission system.

Additionally, Atlantic Coast Pipeline (ACP), in mid-September, applied to FERC to build a 564-mile interstate natural gas transmission pipeline designed to meet electricity generation needs for part of that adjoining region.

ACP, formed by Dominion (45%), Duke Energy (40%), Piedmont Natural Gas (10%) and AGL Resources (5%), would transport natural gas from Harrison, WV southeast through Virginia with an extension to Chesapeake, VA and south through central North Carolina to Robeson County.

"The Atlantic Coast Pipeline is essential to meeting the clean energy needs of Virginia and North Carolina, and has significant benefits for West Virginia as well," said Diane Leopold, president of Dominion Energy.

If all goes as planned, the pipeline should be under construction during the second half of 2016 and in-service in late 2018. The ICF study found one-time construction activity on the project could add an annual average of $456.3 million into the economies of the three states involved, supporting 2,873 jobs in the region through 2019. Additionally, consumers and businesses in Virginia and North Carolina could save an estimated $377 million annually in lower energy costs. ***P&GJ***

Natural Gas Market Dynamics in the Northeast

By, **Scott LaShelle,** Executive VP for Gas Operations, **Great Eastern Energy**

Natural gas markets have gone topsy-turvy. Until recently, prices around the country were generally pretty similar, with gas costing a bit more in the Northeast, far from where it was produced on the Gulf of Mexico coast. But that reality has changed dramatically in the last few years.

Flipping the historical dynamic, a deluge of gas produced in the Marcellus Shale region – responsible for over 20% of national production as of late spring, up from virtually zero in 2010 – has made gas prices in its backyard (western Pennsylvania and its environs) much cheaper than in some other parts of the country, such as the Midwest, Far West and Mid-Atlantic.

The other repercussion of exploding production in the Marcellus is price uncertainty. As shale gas production continues to expand, no one knows precisely how the tug-of-war between supply and demand will play out.

Will burgeoning supply keep gas cheap? U.S. shale gas production has risen from 33 to 42 Bcf/d in just 18 months and is now responsible for almost 60% of all U.S. natural gas production. Or will cheaper gas drive up local consumption in the Northeast and nearby Rust Belt, and tempt shippers with opportunities to pipe it away and profitably sell the gas outside the region, making prices rise?

With gas prices at rock-bottom in the Marcellus, there is evidence that shipment west (for example, through the Rockies Express pipeline east of Chicago) and south (through the Columbia TCO pipeline) to Henry Hub and the upper south, as well as underground storage, are on the rise as sellers seek more expensive markets outside the Northeast and wait for the coming winter.

Additionally, there has been a renaissance in the U.S. petrochemical sector, a source of new demand. Chemical manufacturers making plastics and fertilizer are guzzling large quantities of cheap gas – though no one knows quite how much – because some producers use their own gas onsite and report only what they ship out by pipeline.

This complex web of supply-and-demand factors means that no one knows for sure which way prices will turn. Layered on top of this is the ultimate uncertainty: weather. Always hard to predict, doubts remain whether cool temperatures – and consequent lower gas consumption needed to power air conditioning – will persist this summer, as the National Weather Service (NWS) has predicted.

A cool summer and mild winter are expected as the current El Nino picks up speed. But weather is fickle and unpredictable. While some weather and industry experts have been expecting otherwise, so far the NWS has been vindicated: the Fourth of July weekend was 9ºF cooler than average in New York and Boston, leading daily-market prices to tumble to less than one dollar per million Btu.

These spot prices hit record lows at the Algonquin Citygate location outside Boston and also in New York, roughly one-third of the going rate nationally and the monthly NYMEX levels. Consequently, recent natural gas prices in the Tri-State and New England area have, at a bit below $2.50/MMBtu, been 35-50% below last summer's and roughly 15% below the national average.

But will the trend persist? Will the weather stay cool and will gas producers and shippers keep the spigots wide open in the Northeast? Time will tell. In the meantime, customers are enjoying their lower bills. ■

Scott LaShelle is co-manager of Freepoint Commodities' East Gas business and the newest member of Great Eastern Energy's executive board.

Appalachian Midstream Operators Face Myriad of Challenges

By **Joseph K. Reinhart,** Co-Chair, **Babst Calland's Energy and Natural Resources Practice Group**

This has been a busy year of new challenges and issues facing the Appalachian oil and gas industry as rig count in the Appalachian Basin and elsewhere is down substantially compared to the previous two years.

A significant challenge ahead for shale developers in a lower price environment is to continue to be active in finding land, drilling wells and getting the natural resource to market. This article concerns our most recent report, published in May, on the issues and challenges facing midstream operators in the Appalachian Basin.

As regulatory, legal and market pressures increase, producers and midstream companies will need to rise to the challenge of maintaining growth and profitability amid a myriad of issues related to oil and gas transactions, due diligence, state and federal regulatory matters, local government challenges, lease disputes, royalty interest determinations, and title review.

The Marcellus and Utica shales have proved to be extremely productive, with the former at nearly 17 Bcf/d of gas. The second-highest producing region in the nation – Texas' Eagle Ford – amounts to less than half of the Marcellus production. This productivity is not just because the Marcellus has a big footprint – the productivity per rig is the highest in the nation and about 40% higher than the number two basin, the Haynesville.

In a climate of low commodity prices and increasing regulatory requirements on the industry, there is significant concern in the business community that any new taxes will further discourage capital investments in the basin.

We find ourselves at the outset of phase three in the Marcellus development. We know that many operators with long ties to the region are experiencing commodity prices too low to sustain operations, even without onerous new state and local regulatory requirements. Instead of fewer, bigger players in the Appalachian Basin, we have witnessed new entrants and a dynamic field of companies.

Regulatory Impacts

The past decade has brought many new regulatory requirements for conventional and unconventional operators and 2015 has shaped up to be perhaps the most tumultuous year yet.

Our energy attorneys have played a leading role in making the industry's voice heard on the latest iterations of the long-running process of amending Chapter 78 rules in Pennsylvania. The new rules, if adopted as proposed, will impose significant burdens and create tremendous shifts in how companies manage conventional and unconventional assets.

As much attention has focused on the potential effects of hydraulic fracturing and deep well disposal on seismic events, regulators are considering sweeping changes to what operators will need to install and monitor at these facilities, with potentially major ramifications to underground injection availability, particularly in Ohio. And lurking behind every one of these major shifts are reporting and recordkeeping requirements that will increase administrative burdens and may bring new and weighty legal and operational considerations.

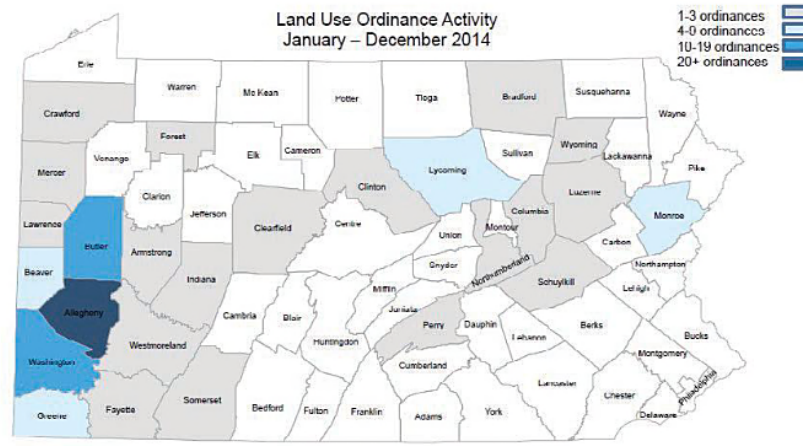
Chapter 78 Sets Pace

Pennsylvania's draft-amended Chapter 78 rules remain the focal point of environmental challenges for the industry. The issues on the table are almost too numerous to list – waste handling, water sourcing and storage, site restoration, retention ponds, tanks, noise mitigation, public resource protection, stream and wetland buffers, orphaned and abandoned wells, cleanup standards, and many others. Most industries have not dealt with this many critical environmental issues in one decade – yet the oil and gas industry is facing them all at once in Appalachia.

The Pennsylvania Department of Environmental Protection's (PADEP) proposed revisions to the environmental protection standards of its oil and gas regulations will be the most significant regulatory development facing the industry through 2016. If the rules are adopted as currently proposed, the industry will face significantly more regulation, potential permit delays and expanded permit conditions, and greater compliance costs than it has in the past. According to the Marcellus Shale Coalition, the proposed regulations could impose a $900 million annual burden on the industry, even when accounting for reduced drilling under current economic conditions.

PADEP will consider public comments on the revisions, known as the Advanced Notice of Final Rulemaking (ANFR), and plans to submit a final rule to the Environmental Quality Board (EQB) in the fall. If the EQB votes to adopt the final regulation, it will be sent to the House and Senate Environmental Resources and Energy committees and to the Independent Regulatory Review Commission for review.

If approved by these bodies, the final regulation will be submitted to the Attorney General's office for approval. The approved final rule would then be published in the *Pennsylvania Bulletin* and will take effect



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according to a schedule provided in the rule. Under Pennsylvania law, the rule must be finalized by March 2016; otherwise, PADEP will be required to restart the rule-making process from the beginning.

Litigation Continues

With a large number of regulatory and legal issues unresolved for the industry, litigation will remain part of the landscape. Industry will continue to be required to litigate interpretations of statutes and rules by federal and state regulators and environmental groups – with, we hope, favorable outcomes such as in *Citizens for Pennsylvania's Future v. Ultra Resources, Inc.*

Industry will also continue to face issues related to the validity of leases and royalty payments. Finally, property-owner claims of both personal injury and property impact from oil and gas development activities will continue, fueled by claims of groundwater contamination and adverse health effects of shale development.

A decision issued on Feb. 23 in *Citizens for Pennsylvania's Future* is the latest development in the debate over single-source determinations. The court agreed with the permitting decisions made by PADEP that the compressor stations at issue were not located on adjacent properties and thus should not be treated as a single source of emissions. The court disagreed with the Citizens for Pennsylvania's Future's (PennFuture) argument that the compressor stations were functionally interrelated and, therefore, should be aggregated as a single source.

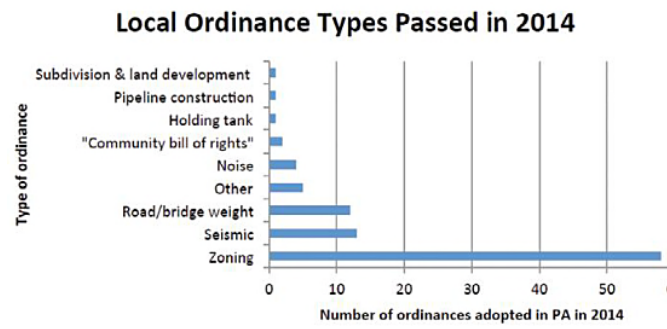
Governmental Landscape

The local government regulatory landscape differs significantly in the three primary states comprising the Appalachian Basin, with each state providing its own unique system of local regulatory authority over the oil and gas industry.

Pennsylvania law continues an uncertain evolution in the aftermath of the Pennsylvania Supreme Court's decision in *Robinson Twp. vs. Commonwealth of Pennsylvania*. In addition to the expected increase in local ordinance activity affecting the oil and gas industry, anti-industry activists are challenging the validity of zoning ordinances, claiming they are not restrictive enough. West Virginia and Ohio, by contrast, confer far less regulatory authority upon local governments.

Local Regulation Growing

Although it is unclear whether a future majority of the Pennsylvania Supreme Court will adopt the *Robinson Twp.* plurality's embrace of the Environmental Rights Amendment (ERA) to Pennsylvania's constitution, one thing is certain – now that they are freed from the constraints of Act 13's stricken sections, local governments are adopting, at an accelerated pace, ordinances that regulate the oil and gas industry's operations. This is sometimes done in an aggressive, restrictive fashion.



Our firm monitors on a daily basis proposed and adopted ordinances in those portions of the Commonwealth located within the Appalachian shale play. In 2014, nearly 100 ordinances affecting the industry were adopted, with municipalities in the southwestern corner of Pennsylvania continuing to lead the way.

What's Ahead?

The oil and gas industry is presented with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many challenges in the economic and political sphere: low commodity prices, efforts to impose or increase severance and other taxes, insufficient pipeline capacity, a vocal opposition, and other issues facing producers and midstream operators.

In the state-level regulatory arena, new regulations are being adopted, especially in Pennsylvania, which has a major expansion of Chapter 78 underway. West Virginia recently initiated a program to regulate aboveground tanks; Ohio has proposed regulations governing construction of horizontal well pads. All three states are examining increased regulation to prevent induced seismicity. Endangered and threatened species protection programs present increased restraints on operations.

At the local level, Ohio has achieved a semblance of stability in defining the scope of local government regulatory authority through the recent Ohio Supreme Court *State, ex rel. Morrison v. Beck Energy Corp.* decision. However, the other two states are far less settled. Pennsylvania, in particular, is still in the process of determining the impact of the *Robinson Twp.* decision on local regulatory authority.

Developing and permitting oil and gas operations on public lands or in areas that potentially affect natural resources will become more complex. Proposed new rules may require additional permitting considerations regarding species other than threatened and endangered species, as well as schools, playgrounds and wellhead protection areas.

Private litigation continues to expand and present its own challenges. Litigation includes nuisance and property damage actions, contamination of groundwater, lease-busting suits, royalty disputes, along with other actions such as medical-monitoring claims.

Transactions, to be handled properly, should involve counsel knowledgeable in all of these areas of the law in order to properly conduct due diligence to evaluate the business units or assets that are being acquired or sold, to assist in negotiations, and to ensure that transactional documents are properly drafted.

Pennsylvania's 2014 impact fee collections declined by nearly 1% compared to the previous year, according to the Public Utility Commission. The Commission will disburse $223.5 million to counties, municipalities and various state funds, down from $225.7 million a year ago. With the most recent round of collections, the fee will have generated $856 million for Pennsylvania and its municipalities.

Initiating a new severance tax could not come at a more difficult time for an industry already under significant economic pressure. Shale operators in Pennsylvania have reduced their 2015 investments by more than $9 billion and many firms have had layoffs. Adopting the proposed severance tax would likely move Pennsylvania from being one of the lowest to the highest energy tax states compared to other major gas-producing states.

In a positive industry development, on June 15, Shell Chemical closed on the property for a 1,000-acre site in Beaver County, PA for building and operating a proposed ethane cracker plant. This plant would turn the natural gas liquid from the nearby Marcellus and Utica shale plays into ethylene, a feedstock for petrochemical production.

Officially, Shell says building the plant is under evaluation, but no final commitment has been made. However, the company reported recently it is proceeding with preliminary site development. Shell needed to buy the land in order to advance the permitting process for developing the site.

Appalachian oil and gas operators continue to transform the nation's energy profile. The environmental and regulatory challenges that vary in the Appalachian Basin states are dynamic and will continue to evolve as the Marcellus and Utica shale industry enters its second decade of operation. ***P&GJ***

Editor's note: This article highlights excerpts of the recently published 2015 Babst Calland Report – Appalachian Basin Oil and Gas Industry: Rising to the Challenge, Legal and Regulatory Perspective for Producers and Midstream Operators. *A full copy of the report is available by writing to info@babstcalland.com.*

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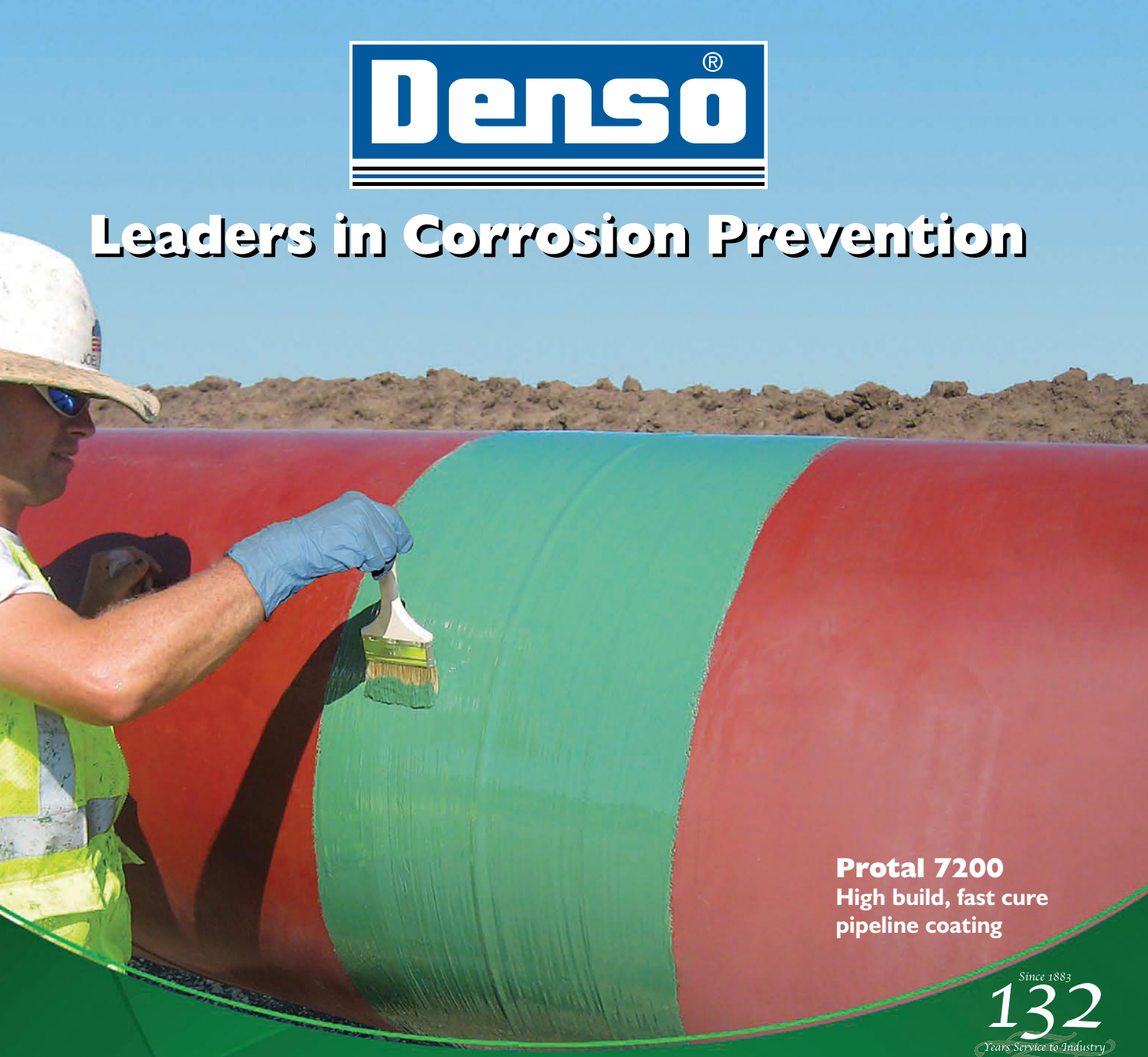

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North America's Midstream Sector Re-emerges

By **Andy Steinhubl** and **Chris Click,**
Principals, **KPMG**

The development of North America's unconventional oil and gas resources has brought new life to the region's midstream sector. The infrastructure necessary to gather and transport commodities to resurgent downstream and chemicals sectors, new gas-fired power generation, and other new demand requires investment approaching a trillion dollars by some estimates.

And investment opportunities translate to growth. However, the midstream sector's history prior to this revolution in unconventional energy resources left it underprepared and ill-suited for the current boom. As a result, the race is on to create the midstream company of the future; a company with the business model and supporting organizational model and capabilities to capitalize on the opportunities.

Though the recent oil price and earlier gas price decline slows the buildout, it also puts additional impetus on further industry consolidation. Creating the midstream company of the future will not be easy, but there is the possibility of significant profits.

In 2005, the Energy Information Agency (EIA) estimated the country would need to import 6.4 Tcf of natural gas by 2014. That estimate proved inaccurate. Last year, U.S. producers provided 25.7 Tcf in domestic production, enough production that they not only met domestic needs, but also positioned the country to become a significant exporter.

The horizontal drilling and hydraulic fracturing technologies that allowed the economic development of the Barnett, Marcellus, and other natural gas shale basins had fundamentally shifted global natural gas flows.

A similar series of events transpired in the development of North America's "tight oil" resources of light crude. The development of the Bakken, Eagle Ford, and several areas of the Permian Basin increased domestic oil production by 2 MMbpd from 2013-15. And despite the subsequent decline in crude prices, production of light tight oil is still expected to rise, albeit it at a slower rate.

This unforeseen increase in domestic oil and gas supply presented an economic gift for North America's chemicals, downstream, and other sectors that consume energy and use feedstocks. The large supply and competitive costs of natural gas shifted North America's position in the global chemicals supply for products such as ethylene and its derivatives.

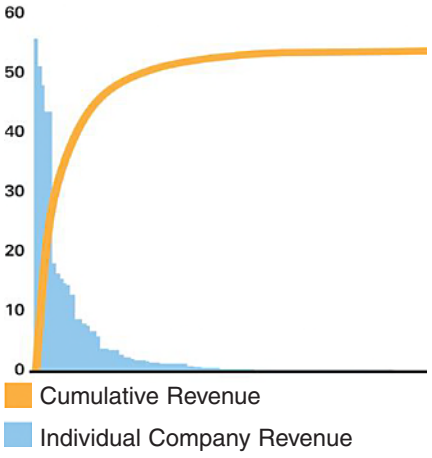
Increased domestic oil production widened price differentials against competing global crude markets, allowing U.S. refiners to boost profits and capture a larger share of global export markets. Downstream companies have moved to capture and capitalize on this boon through a series of significant investments to reduce bottlenecks, kit enhancements, and even to build new projects.

Infrastructure Constraints

The combination of an increased domestic supply of oil and gas and greater downstream processing capacity offers the prospects of a renaissance in U.S. manufacturing subject to one key constraint: the midstream infrastructure necessary to gather the inputs, process them, transport them to downstream hubs, and then move the finished products to markets. In response, a midstream infrastructure building boom is underway in the United States.

A recent study by IHS for the American Petroleum Institute (API) estimated the industry will need to invest $838 billion by 2025 in order to match projected supply and demand. Similar reports cite slightly higher or lower figures depending upon the infrastructure types included in the report, the timeframe of the study, and other underlying factors.

Midstream Industry Fragmentation
Cumulative Annal Revenue ($B) as of Dec. 2014



Source: *Capitol IO Last 12 months revenue data*

Of 205 Midstream companies with reported revenue, 115 out of 205 companies have revenues (last 12 months) below $100M

8 companies make up 65% of cumulative revenue

Energy Transfer is the top company with 24% of cumulative revenue between two MLPs (Energy Transfer Equity and Energy Transfer Partners)

Global Gas Flows

Expectations based on EIA 2015 Scenario in 2005

To put this in perspective, the estimated $838 billion in midstream infrastructure capital investment exceeds similar estimates for capital investment in all transport infrastructure, such as roads, bridges and tunnels during the same period.

Midstream's Growth

It is important to remember that prior to the mid-2000s, onshore oil and gas activity in the United States had declined for nearly 20 years. As a result, the midstream sector was considered a mature, low-growth portion of the value chain. Many large integrated companies not only limited their investments in midstream, but also divested or spun-out midstream assets in order to harvest what value and cash flow they could from such mature assets.

The introduction of master limited partnership (MLP) structures through the Tax Reform Act of 1986 and the Revenue Act of 1987 accelerated the disaggregation of the midstream sector. These pass-through entities, which may only hold qualified income sources including midstream oil and gas assets, offered a lower cost of capital by which to hold mature assets. As of 2014, there were about 200 companies in the U.S. midstream sector and over half were MLPs, according to Capital IQ.

However, the combination of underinvestment, disaggregation and a move toward entities intended to focus on harvesting the cash flow of mature assets meant many participants were not equipped to capitalize on the investment opportunities created by the shale revolution.

Many companies were small and unable to fund new capital investment. Other participants lacked the internal capabilities, such as business development, risk management and project management necessary to carry-out new strategies or projects.

Midstream's Response

The midstream industry has responded well to the initial challenge. The sector has been able to raise significant capital as a result of the significant growth opportunities and the investment advantages of the MLP structure. Between 2005 and 2014, the midstream MLP sector raised $150 billion in capital, including equity and debt financing. Much of the capital funded expansions of existing gathering systems and regional pipeline projects. In 2013 alone, the midstream sector added over 13,000 miles of new oil and natural gas pipelines in the United States.

	Scale and Scope (e.g. Kinder Morgan)	Basin Consolidator (e.g. Regency)	Value Chain Optimizer (e.g. Enterprise)	Customer Service Champion (e.g. Williams)
Drivers	Leverage balance sheet and diversification to take on major project risks not accessible to smaller players Manage both large volumes and breadth of product/service offerings	Gain dominant infrastructure position within a basin Access to 'all' deals in basin; position across local chain	Driving specialization across particular value chains; e.g., liquids Providing integrated services from wellhead to end user	Work closely with customers to develop new opportunities and future project work Premium customer service
Risk	Preference for project vs. commodity or commercial risk. Breadth of portfolio and company scale mitigates risk	Local knowledge advantage in taking commercial risk; in the flow of all deals and info locally	Value chain expertise creates advantage in undertaking liquids commodity risks	Intimate customer knowledge, both on gathering and end user ends create advantage in taking commercial risks
Example	Palmetto Project is a $1billion project with a design capacity of 167,000 barrels per day will provide Gulf Coast producers with access to new markets in the Southeast	Utica Ohio River project to connect all Utica gathering lines into a trunk line creating the first mover advantage for lean gas take away option	Enterprise joins with Pioneer to get permission from the U.S. government to export Condensate	Focused on Northeast pipeline and midstream expansion projects moving from Marcellus to the Utica shale region.
Capabilities	Project excellence Operational excellence	Stakeholder Engagement Project Development	Business Development Supply Contracting Strategy	Customer Engagement Commercial and Project Development

A portion of the capital raised was also used for acquisitions as companies that lacked either the number of new projects necessary to maintain a consistent flow of drop-down activity or the internal capacity required to carry out such projects. Deal counts have grown from 39 to 45 from 2011-14, and the average deal size increased from $1.9 billion to $3.9 billion during the same period. Midstream merger and acquisition (M&A) activity is expected to continue to grow, especially if the recent downturn in commodity prices extends through the remainder of the calendar year.

However, consolidation, in and of itself, does not represent an effective long-term business strategy. Similarly, growth through organic projects is more of a tactic than a strategy. In our perspective, the midstream sector participants to truly capitalize on what a recent Williams Companies investor presentation referred to as a "once in a generation industry super-cycle" will define and implement robust strategies – a series of moves that provides them with a differentiated set of assets and capabilities that allows them to increase profits over current trends.

Model of the Future

First, what is our ambition in terms of measurable, economic milestones, as well as more qualitative descriptions of the type of company that we want to be? Second, what is our area of focus with respect to the types of plays that we will pursue, the exposures that we will accept, and the means by which we will make money? Finally, how do we intend to source its opportunities including the desired balance between organic and inorganic growth?

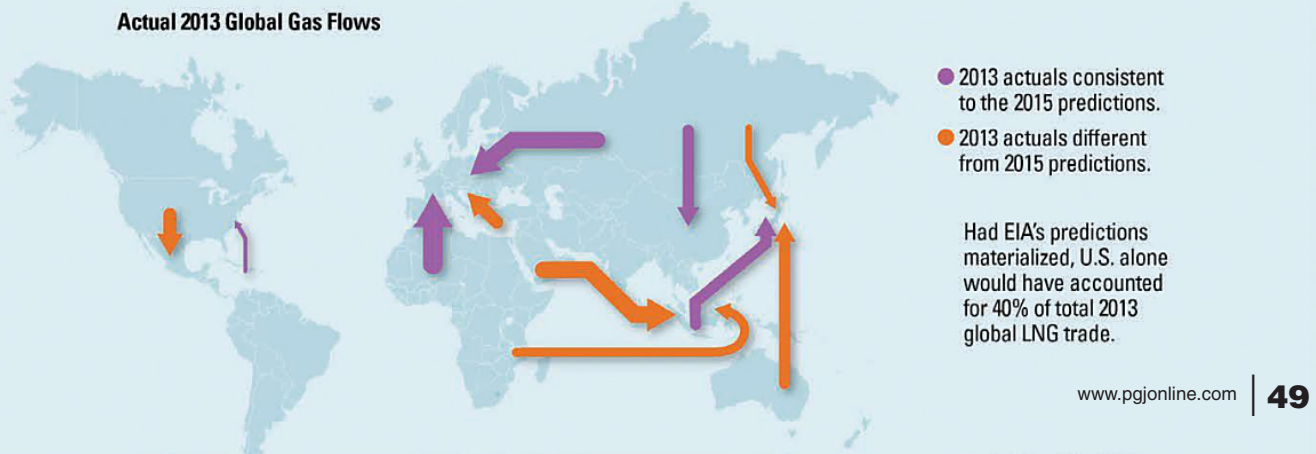
Based on our observations of primary sector participants, their public comments to the market, and their recent investments, we see at least four "pure-tone" business models that companies are pursuing as illustrated above.

We recognize few companies, if any, are wholly consistent with such conceptual models and there are potentially other effective business models available. However, based on our work across the midstream sector, we believe companies need to be considering high-level business model choices and their implications before thinking specifically about tactics.

Such an approach helps align an executive team around an intended path, provides boundary conditions for future choices, such as which markets do we want to expand in and what is the appropriate mix of M&A vs. organic growth.

For example, MarkWest Energy leveraged its experience in the natural gas and NGL value chain to develop leading positions in the Marcellus and Utica basins. It then capitalized on the strong customer relationships it established in those regions to increase customers in other basins, including the Permian.

Sponsored MLPs provide an interesting lens through which to consider participation choices. At one bookend, sponsored MLPs might define strategy largely in terms of the



pace of parent company drop-downs, which by definition are close to existing parent businesses. At the other bookend, sponsored MLPs might pursue growth agendas beyond their parent company geographies and businesses and thus face participation choices similar to that of independent MLPs.

Operating Model

Decisions regarding a business model have profound implications for an organization's capability requirements. A company pursuing a business model focused on large organic projects, for example, must ensure that it is particularly effective – meaning better than its peers – at capital project management.

A company that accepts a greater degree of commodity price exposure in its contractual approach requires a different set of risk-management capabilities than a competitor that focuses on volumetric or fee-based commercial arrangements.

Defining the necessary capabilities is the first step. Building those capabilities is the next and more challenging step, as a true capability is a complex combination of individual skillsets, underlying processes, and enabling technologies.

The process of identifying and building capabilities can be particularly challenging for sponsored MLPs. Inevitably, the discussion arises with respect to which particular services, be they front, mid, or back office, can and should be provided by the parent company and which should be developed within the MLP or outsourced to a third party.

In many cases, this debate is even more complex because the parent and sponsored entity have not sufficiently discussed the degree to which, or pace at which, the sponsored entity will expand beyond the footprint of the parent company's asset base.

Operating Efficiencies

In light of the recent downturn in oil and gas prices, midstream companies must focus on operating efficiencies to hold costs in check. This is especially important, given the general perception that the downward trend is a long-term shift that will lead to structurally lower expansion in oil and gas production.

Approaches to cost management range from short to long-term, but they all share a focus on creating transparency into how spending supports organizational priorities.

Disaggregating costs into meaningful categories helps to identify where efforts should be directed to unlock value. After identifying the categories that have the greatest effect on operating efficiency, even more detailed analytics can identify which of these items are controllable. This will help determine what fundamental changes to business rules, policies, or procedures are required to ensure that these items are closely tracked and actively managed in the future.

Regardless of the extent to which external market realities, such as product pricing and regional flows may shift over time, a rigorous approach to managing costs will help set the tone for the organization and serve as preparation for success in a future that looks to be no less volatile than the past few years.

Capitalizing on Opportunities

The supply shock from shale gas and unconventional tight oil, and the resulting need for midstream infrastructure, placed the midstream industry at the center of a complex and rapidly shifting set of market forces. Recent OPEC policy shifts to maintain market share, coupled with this unconventional supply shock, have brought new complexities of lower and fluctuating commodity prices and expectations of a slower capacity buildout.

Consolidation, however, was already a trend and all the more likely in light of the additional pressures brought on by the industry slowdown. To capitalize on the opportunities facing the industry, companies need a dedicated focus on building advantaged capabilities, making the right business model choices and adaptations, and creating operating model flexibility to develop a sustainable, long-term competitive advantage. Extraordinary returns are the payoff for those companies that make the right moves. ***P&GJ***

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Latin America Forced to Face Growing Supply-Demand Gap

By **Nelly Mikhaiel,** Senior Consultant, **Nexant**

Latin America's prominence on the world gas stage has increased over the last several years. Although it is well-endowed with natural gas resources, the region has struggled to find its footing as both a natural gas producer and consumer. Consequently, Latin America's potential as a natural gas import province is the topic of increasingly animated debate.

Potential upstream investors, midstream infrastructure developers, and the financial and legal institutions keen to support the development of Latin America's hydrocarbon supply and distribution all have a vested interest in understanding its role in the global gas business of today and tomorrow.

But even in this day and age of instant communication and online research resources, the acquisition of knowledge about Latin American gas markets is not easy. This is attributable to several factors, such as language barriers and the generally opaque nature of many Latin American countries' natural gas businesses. Public domain information on the structure and dynamics of regional and country-specific gas industries may be limited or difficult to obtain.

Without the benefit of personal contacts within the national hydrocarbon companies and energy regulatory bodies, it is difficult for outsiders to form an understanding of individual countries' gas industries, let alone the regional picture. This, in turn, limits the ability to form a truly global view of the natural gas sector.

To address these issues, Nexant plans a multi-client study to profile and assess the current and future natural gas markets in Latin America. The study will forecast regional gas trade flows, with an emphasis on the region's existing and future LNG-importing countries.

Competitive Terms Lacking

A gap between indigenous natural gas output and consumption has emerged in some Latin American gas-producing states in recent years. Although the region's overall production has grown over the last decade (Figure 1), only a few countries such as Peru and Venezuela have remained self-sufficient in natural gas.

Others like Argentina, Brazil, Chile and Mexico have struggled to produce sufficient volumes to meet demand. In the past, various factors like the indifferent pace of energy market reform and an emphasis on oil production adversely affected natural gas production in some Latin American countries. Adding a further layer of complexity has been the struggle to attract outside investment to gas sectors, especially the upstream.

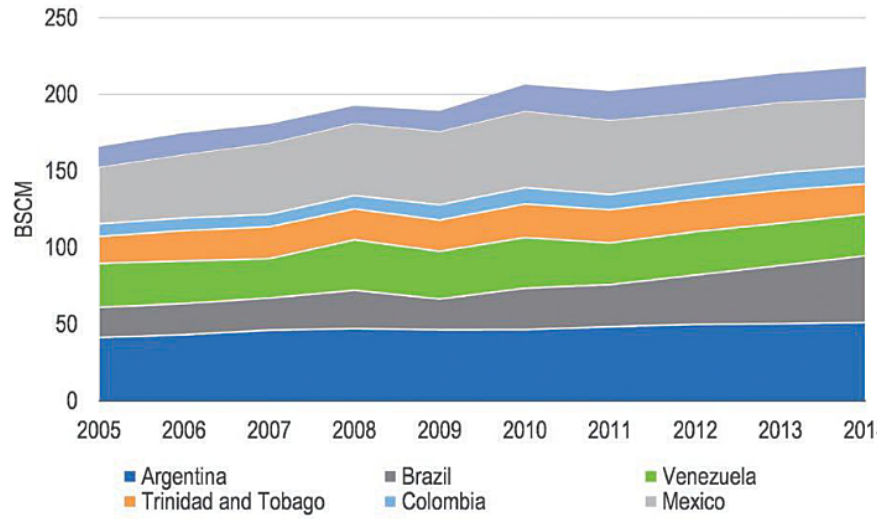

Figure 1: Historic natural gas production in Latin America
Source: World Gas Model

Not all Latin American countries have offered investors competitive terms and provided the requisite regulatory and fiscal certainty, especially regarding the sanctity of existing contracts. Consequently, natural gas production in parts of Latin America has struggled to keep up with demand – a demand that has in many cases been stimulated by artificially low end-user prices. Economic expansion and the intermittent availability of renewable power-generation sources are other factors supporting demand growth, especially by the power sector.

Due to the growing indigenous supply-demand gap, certain Latin American countries such as Argentina, Brazil, Chile and Mexico are increasingly dependent on imports. At the other end of the scale are Central American and some Caribbean countries with no indigenous production and limited access to imports.

Pipeline gas imports have been the traditional source of external supply for several Latin American countries if geography, geology and geopolitics allow for it, but this is not always possible:

- **Insufficient gas to fulfill export commitments** – Traditional pipeline gas exporters like Argentina have been unable to sustain export levels due to the mismanagement of its natural gas industry as a whole. In addition to its inability to continue pipeline exports to neighboring countries, Argentina was obliged to become an LNG importer in 2008. Brazil and Chile, which previously imported Argentinean gas via pipeline, also joined the regional LNG importers club at about the same time.
- **Lack of proven reserves** – Bolivia is a key regional pipeline exporter to southern Latin America, but its ability to boost exports is contingent on proving up more reserves at home and satisfying domestic requirements first.
- **Lack of connectivity** – New cross-border pipelines could "gasify" parts of Latin America that are isolated from existing supply sources. A regional Central American network similar to Sistema de Interconexión Eléctrica de los Países de América Central (SIEPAC), which is an interconnec-

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tion of the power grids of six Central American nations, embodies this type of thinking. However, a host of issues have combined to keep the concept of an integrated Central American gas pipeline confined to paper. These include a lack of demand to justify such a costly initiative and a lack of consensus on key commercial and regulatory issues.

- **Luck of geography** – Not all Latin American countries are favorably located to interconnect with secure and abundant gas supply sources. Their neighbors may lack the gas reserves to comfortably export gas, or they may lack suitable terrain or a cordial relationship with their neighbor to make such an arrangement feasible.

As a result, countries with growing gas supply-demand gaps have increasingly turned to external sources – that is, LNG – to make up the supply shortfall. This growing dependence is borne out by the numbers: Latin America's LNG imports totaled 27 Bcm in 2014, up from less than 1 billion standard cubic meters (Bscm) in 2005 (Figure 2).

So keen is the need for LNG in some of the region's countries that Argentina and Brazil have outbid top-tier Asia Pacific LNG importers for cargoes in recent years. Although countries such as Chile and the Dominican Republic have the security afforded by long-term supply contracts, importers in Argentina and Brazil have adopted a more opportunistic approach toward cargo procurement.

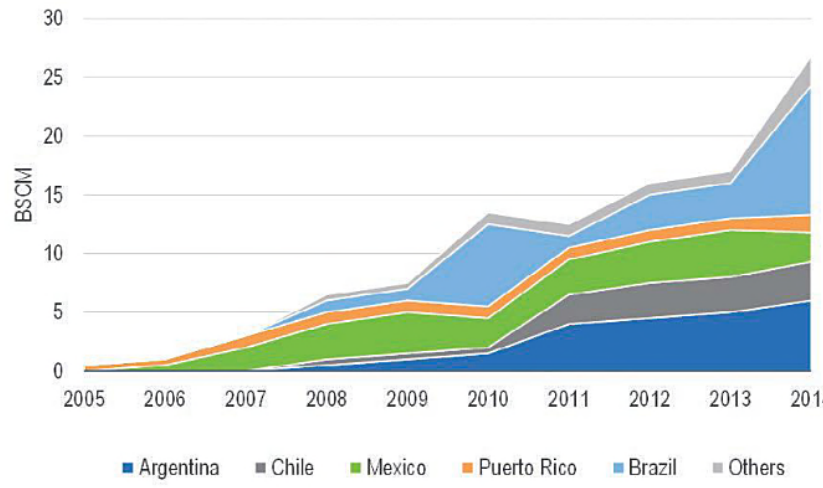

Figure 2: Latin American regasification throughput (2005-2014).

Until fairly recently, spot market LNG procurement took place against a backdrop of high oil prices, strong competition from Asia, and constrained global LNG supply. This resulted in record-high prices being paid for cargoes by certain Latin American buyers – prices that the domestic markets in these countries were ill-equipped to bear.

The emergence of Latin America as an LNG import province and its ability to occasionally compete with east of Suez buyers is a significant development in the global LNG business. Existing and prospective global LNG suppliers have taken note: Latin America has been targeted by potential sellers in areas as diverse as the United States and East Africa.

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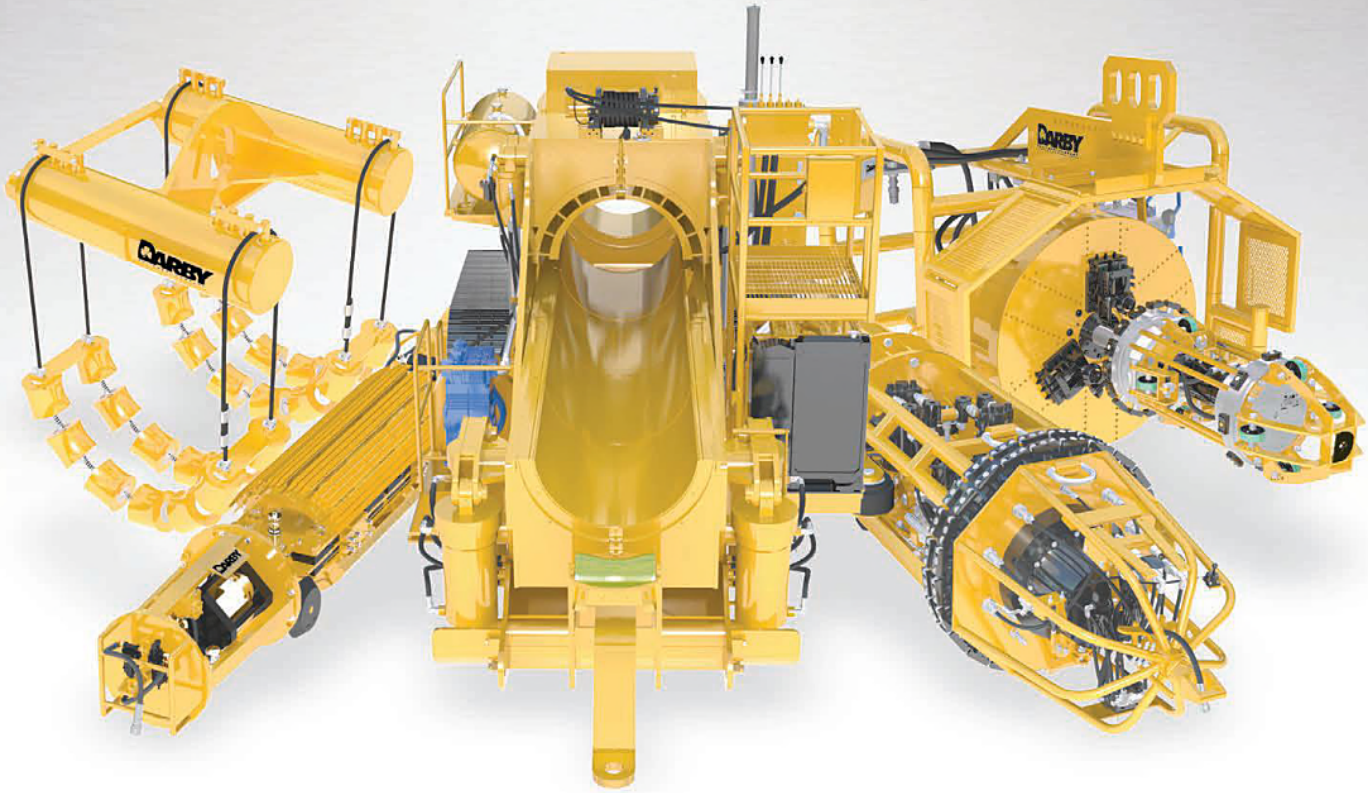

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Taking into account the challenges facing Latin American gas production in the face of growing demand, especially in the key countries of Argentina and Brazil, regional buyers will be seeking new deals on LNG. Going forward, Latin America's role in the evolving global LNG marketplace will be a topic of great interest for competing LNG buyers, as well as to sellers west and east of Suez looking for new market opportunities.

What Next for Latin America?

Looking ahead, natural gas will be increasingly favored throughout Latin America as a power-generation fuel and industrial feedstock. Even Latin American countries that emphasize the importance of renewables in the energy mix can stand to benefit from natural gas: thermal power generation is a reliable source of energy, whereas climate chaos may affect weather-dependent sources of power production, such as rainfall for hydropower generation.

Although the outlook for increased natural gas demand is fair, optimism must be tempered with the knowledge that investor confidence in the energy regimes of some Latin American countries is not strong. If this lack of confidence prevails, the prospects for new domestic gas projects will be adversely affected, with a knock-on effect on overall gas consumption.

On the supply side, Latin American natural gas production is expected to satisfy the bulk of regional demand requirements. A contributing factor to the robust gas demand outlook is the expectation of significant production growth in the key countries of Argentina, Brazil, Mexico and Venezuela.

Argentina is believed to have significant unconventional hydrocarbon resources, and there are hopes that additional exploration will enable the nation to echo, although not replicate, the shale gas production success in the United States. Meanwhile, Brazil's pre-salt deposits in the Campos and Santos basin have been the focus of great interest and investment, and are already contributing to Brazil's indigenous gas supply-base.

For its part, Mexico is optimistic the energy reforms instituted in 2014 will attract the foreign investment needed to increase its gas production base. Not surprisingly, all these optimistic gas production forecasts have resulted in ambitious domestic gas use plans in the host countries. There are also high hopes the region's overall gas import dependence, especially LNG, will eventually fall on the back of higher gas production.

However, production outlooks are always subject to a degree of uncertainty, and the challenges facing Latin America as a gas-producing province are not insignificant. Wild cards affecting the outlook for gas production include disappointing drilling results, difficulty attracting sufficient investor support, uncertain regulatory regimes, a lack of confidence in regional national petroleum companies and high break-even costs for new sources of production.

If future production falls short of expectations, the region's LNG import dependence may continue – and possibly grow. The failure of Latin America's indigenous production plans to materialize as planned may result in one of three outcomes: a greater-than-expected reliance on imported gas, a longer-than-expected reliance on imported gas or a combination of the two.

This could affect investment plans in the region's power-generation and industrial sectors, and the price of gas for commercial and residential end-users. For downstream players hoping to launch gas use projects based on abundant, reasonably priced indigenous supply, the failure of indigenous production sources to materialize and the consequent dependence on possibly costly imported gas would be cause for concern.

Although intraregional pipeline imports will remain an important part of the gas supply mix for certain Latin American countries, the roster of regional LNG importers is expected to swell over the next few years: Colombia, Cuba, El Salvador, Panama and Uruguay all have

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LNG import plans in various stages of maturity.

This raises questions about potential supply sources for existing and future Latin American LNG importers. Intraregional LNG flows (Trinidad and Peru) will continue to satisfy the bulk of Latin American demand, according to Nexant's proprietary World Gas Model, but the United States will play an increasingly important role after 2020. Thanks to surging unconventional gas production, projected U.S. natural gas supply will be sufficient to underpin a large export sector, with deliveries to customers via pipeline gas and LNG.

The Panama Canal expansion could further foster a diversity of supply and lower the cost of natural gas, in particular from Trinidad and Tobago or the U.S.-to-Pacific markets. Once the expansion is completed, the majority of the world's LNG tankers will be able to pass through the canal, both opening Asian markets to Latin American natural gas producers and expanding landing options for Central American countries on the Atlantic and Pacific coasts. ***P&GJ***

Nexant's proposed study "Latin America as a Natural Gas Province: Getting Acquainted with the Great Unknown" is targeted for completion at the end of the fourth quarter.

Editor's note: For the purpose of this article, Nexant's definition of the region encompasses Argentina, Bolivia, Brazil, Chile, Colombia, Costa Rica, Cuba, the Dominican Republic, Ecuador, Mexico, Peru, Trinidad and Tobago, Uruguay, and Venezuela.

Author: Nelly Mikhaiel *is a senior consultant with Nexant's Energy and Chemicals division. She has 15 years' experience as a natural gas consultant, with a focus on LNG. Mikhaiel earned both her bachelor of arts and Ph.D. degree at the University of Western Australia.*

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Feds Want Tougher Rules for Pipelines after Series of Spills

P&GJ Staff Report

Federal officials said Oct. 1 they want tighter safety rules for pipelines carrying crude oil, gasoline and other hazardous liquids after a series of ruptures that included the costliest onshore oil spill in the nation's history in Michigan.

"This is a big step forward in terms of strengthening our regulations," said Marie Therese Dominguez, chief of the Transportation Department's Pipeline and Hazardous Materials Safety Administration (PHMSA). "It's timely, and it's raising the bar on safety."

The Department of Transportation (DOT) proposed expanding pipeline inspection requirements to include rural areas that are currently exempt and for companies to more closely analyze the results of their inspections. The agency also would make companies recheck lines following floods and hurricanes, and submit information about leaks and other problems on thousands of miles of smaller lines that fall outside of existing regulations.

The proposal covers over 200,000 miles of hazardous liquids pipelines that criss-cross the nation – a network that expanded rapidly over the past decade as domestic oil production increased. Pipeline ruptures in recent years have fouled waterways in Michigan, Montana, California, Virginia and elsewhere with crude oil and other petroleum products.

"This is a big step forward in terms of strengthening our regulations," said Marie Therese Dominguez, chief of the Transportation Department's Pipeline and Hazardous Materials Safety Administration (PHMSA). "It's timely, and it's raising the bar on safety."

The new rules have been in the works since 2010, when 840,000 gallons of crude oil spilled into the Kalamazoo River in Michigan and other waterways from a ruptured line operated by Enbridge of Calgary, Canada.

Investigators with the National Transportation Safety Board cited corrosion and a crack in the line as the probable cause, and blamed the accident in part on ineffective oversight and weak regulation from the pipeline safety administration. The leak went undetected for 17 hours, and cleanup costs for the spill exceeded $1 billion, making it the costliest onshore oil spill ever in the U.S., NTSB Chairman Christopher Hart said recently in testimony before Congress.

If the proposed changes had been in place, the requirements could have prevented the Michigan spill and 238 other accidents between 2010 and 2014, transportation officials said. The other accidents released over 10 million gallons of oil, gasoline and related products and resulted in $118 million in costs and damages.

The proposed rules also expand requirements for leak-detection systems to include new, regulated pipelines. Current rules cover only lines in areas with a large population or environmentally sensitive features such as drinking water supplies.

John Stoody, vice president of the Association of Oil Pipe Lines, an industry group, said much of the proposal involves work that companies already do voluntarily, such as periodic inspections of lines in rural areas. By imposing requirements on the timing of maintenance, federal officials run the risk of diverting attention from high-consequence areas with large populations or environmental features, he said.

"That's maintenance dollars that would not be spent on higher-priority areas," Stoody said.

Despite its broad sweep, the federal proposal was characterized as an incremental step forward by the head of the Pipeline Safety Trust, a Bellingham, WA-based advocacy group.

"There's some good stuff in there," trust Executive Director Carl Weimer said. "But we're disappointed that it took five years and we don't' think it's as significant as (federal officials) tried to portray it."

Weimer pointed to the requirement to check lines after natural disasters, such as the flooding blamed in a 2011 ExxonMobil pipeline rupture that spilled 63,000 gallons of crude oil into Montana's Yellowstone River. Companies also should take steps ahead of time to guard against such occurrences, he said.

The changes could cost pipeline companies a combined $22.5 million annually, according to the agency. Dominguez said she hopes to finalize the rules sometime next year.

A 2011 pipeline law passed by Congress included requirements for remote-controlled and automatic emergency valves that can quickly shut down the flow of oil. Advocates say such valves are a simple way to limit damage from accidents. The American Petroleum Institute has said retrofitting lines with remote-controlled valves could cost up to $1.5 million per device. Transportation officials plan to address the issue in a separate proposal.

The delay was criticized by Rep. Lois Capps, D-CA, whose district includes the Santa Barbara County coastline where a May 19 rupture of a corroded pipe owned by Plains All-American Pipeline of Houston spilled over 100,000 gallons of crude, some of which flowed into the ocean, formed a large slick and stained beaches.

"Federally regulated oil and gas pipelines currently are not required to use the best automatic shut-off technologies available and that needs to change," Capps said in a statement.

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Also on Oct. 1, federal regulators announced they are assessing a $2.6 million civil penalty against ExxonMobil Pipeline Co. for a 2013 oil spill in Arkansas. PHMSA released its final report on the Pegasus pipeline leak that spilled roughly 3,190 barrels of oil near Mayflower and Lake Conway about 20 miles north of Little Rock in March 2013. The agency said in its order that the company violated regulations involving the line's integrity, operation and maintenance.

The U.S. Department of Transportation agency's spokeswoman Artealia Gilliard wrote in an email that "time-intensified defects of originally manufactured pipe" led to the rupture in the pipeline. She said an investigation found the violations.

The northern portion of the pipeline, which runs through Mayflower, remains closed. The agency granted a request to return the southern segment of the line to partial service with reduced pressure in July 2014.

The report examined nine violations and outlines the responsibility the company had for those items. It said the company had switched to assessing larger portions of the pipeline instead of smaller segments, which delayed the results of the integrity assessments and took longer than the agency allows.

In addition to the $2,630,400 penalty, the order requires the company to update the methods it uses to assess the pipeline to better identify those lines that are more susceptible to seam failures. A 22-foot seam in the Pegasus pipeline ruptured to cause the 2013 spill.

"ExxonMobil Pipeline Company has received and is evaluating its options with respect to PHMSA's final order for the 2013 Mayflower incident," ExxonMobil spokesman Christian Flathman wrote in an emailed response to *The Associated Press*.

The report said the company argued that the agency couldn't issue a civil penalty and that if it did, the amount should be capped at a much lower amount because some of the nine violations fell under the same regulation.

In August, a federal judge approved a $5 million settlement agreement among the pipeline operator, the state of Arkansas and the federal government. ExxonMobil agreed to pay $3.19 million to the federal government and nearly $1.9 million in fines, fees and other payments to Arkansas.

The order said the company must also work out procedures to better train those involved in risk assessments of pipelines to err on more conservative estimates. The company must also maintain the required schedule of inspections, use qualified personnel to conduct the assessments and identify methods to make sure identified threats are not discounted.

Most of the requirements have a timeline of between 30 and 150 days to be completed under the order. The agency noted that if the company is not granted an extension, additional civil fines up to $200,000 per each unmet requirement per day can be issued. The company has 20 days to remit the $2.6 million civil penalty under the order.

The report says the agency considered the history of ExxonMobil Pipeline Company's prior offenses, noting there were 12 offenses in the last five years. ***P&GJ***

Getting the Basics of Construction Productivity Right

By **Dustin Bass** and **Sabine Hoover, FMI**

The U.S. midstream oil and gas construction industry has experienced tremendous growth over the past decade, forcing industry stakeholders from across the nation to work together under extreme environmental conditions, compressed project schedules, persistent labor fluctuations and ongoing cost pressures.

Despite collapsing crude oil prices and declining natural gas prices, the midstream oil and gas market is poised for continued strong growth – mainly due to the huge transportation demand for getting oil and gas from the wellheads to end users. Within the pipeline construction sector, planning, designing, and building activities remain historically high and are expected to remain robust for the near future.

Though business remains strong, many construction projects continue to be plagued by escalating cost overruns, project delays, mounting risks and declining productivity – particularly on megaprojects. Indeed, what we have is an industry imbalance shaped by volatile market cycles and the resulting decades-long push and pull among owners, engineers and contractors.

"The industry hasn't been able to find a good equilibrium where all stakeholders get what they want," said a large global engineering firm's director of construction.

In FMI's discussions and project work with industry leaders in the midstream construction space, we have found many firms operate in a highly chaotic business environment and don't understand the basic "blocking and tackling" of construction. In this article, we explore the preparations needed to prepare a company for the next large oil and gas boom and provide straightforward tips for achieving this goal.

Finally, a case study on JV Driver (a Canadian industrial construction company) and one of its preferred suppliers, Intelliwave Technologies Inc., highlights how a creative partnership has resulted in the development of innovative tools to improve site logistics and reduce rework through effective equipment and material tracking in the oil and gas sector.

An Old Story

The U.S. construction industry isn't readily associated with words like "cutting edge" and "innovation," particularly when compared to high-tech industries such as aerospace or biotechnology. In fact, the U.S. construction industry has a lengthy history of productivity decline, according to numerous industry research studies.

Matt Stevens, president and management advisor at Stevens Construction Institute, Inc., calculated the U.S. construction industry's labor productivity from 1993-2013. He stated, "Generally, the negative changes over the last three decades have outpaced the positive changes. Lack of consistent engagement by construction project stakeholders to each other has made project information flow unevenly, causing chaos. The contracts continue to be draconian, so each party acts with as much legal insulation as possible."

Though one could debate the many reasons for ongoing productivity decline, keep in mind the true meaning of productivity. At its most basic level, productivity describes a relationship between physical inputs and outputs. The formula is disarmingly simple:

Productivity = Units of output/Units of inputs

A productivity index highlights the ways that a company can extract an increasing number of units of output per labor hour, per pound of materials or per machine. Traditionally, productivity in the oil and gas construction industry has mainly focused on direct labor. Given the continuing productivity decline, however, industry leaders now question some fundamental business practices the industry has taken for granted for decades.

"We need to move away from Einstein's definition of insanity: doing the same thing over and over again and expecting different results," said a supply chain manager of a large Canadian oil sands operator. "We just have to try something completely different."

In a recent article, Bob Prieto, senior vice president at Fluor Corporation, agreed: "The persistent performance challenge drives me to question whether the theoretical foundations of project management theory – as it is widely practiced today – are sufficient to meet the challenges of large projects. … Perhaps large projects, and especially large multi-project programs, require a different theoretical foundation than the traditional theories that underpin our management practices…"

The productivity formula raises the question of whether the construction industry as a whole needs to fundamentally rethink the "units of input" by exploring new and groundbreaking business practices. For example, FMI has begun to see progressive midstream oil and gas construction firms invest heavily in building project manage-

ment capacity by innovating in areas such as prefabrication, technology, knowledge management and communication, to name a few.

In coming years, oil and gas owners will likely focus on construction companies that can limit rework orders, optimize labor, equipment and materials scheduling, and use a modular approach to project management. These tactics will help improve productivity and manage costs in a tight labor market – two key concerns for owners in this sector.

"We're seeing some advancement of processes and equipment through the use of technology, said Don Thorn, president at Welded Construction. "The long, large-diameter pipes will probably be done with mechanized welding in the future, and that will certainly help with the craft shortages to some extent. As a result, we will need people with experience utilizing mechanized welding equipment and increased training activity from our labor forces."

In Canada, oil/gas companies and oil sands operators are overcoming productivity issues by investing more heavily in innovative technologies. In a recent FMI research study focusing on the Alberta oil/gas and oil sands industries, conversations with owners, EPC (engineering, procurement, construction) firms and energy infrastructure construction companies revealed some widespread dysfunctions among project stakeholders, which have resulted in significant project cost overruns and low project performance on numerous high-profile projects.

In light of these industry challenges, forward-thinking companies are looking at new ways to collaborate with project partners to improve overall project performance – and ultimately, corporate profits.

The following case study highlights an innovative partnership between two firms – JV Driver, a Canadian industrial construction company, and Intelliwave Technologies Inc., one of JV Driver's preferred suppliers. It shows how these two firms are dramatically improving site logistics and reducing rework through effective equipment and material tracking in the oil and gas sector.

Redefining Field Logistics

Since 1989, JV Driver of Canada has been providing industrial construction services to the oil and gas, energy, petrochemical, forestry and mining sectors. Over that 25-year span, the company has come to appreciate the value of innovation and technology in ways that many competitors have yet to recognize.

"Innovation is definitely a big part of what we do," said Dale Beard, president, Intelliwave Technologies Inc., one of JV Driver's Preferred Suppliers. "We're changing the way construction is done and using innovative technologies that have already been tested by other industries – not just in construction."

In the construction world, about two-thirds of projects' costs are spent on materials and equipment (30%), while the remaining 30-40% is spent on labor. Therefore, being able to manage and track these resources becomes critical in saving on cost and time.

"Construction has typically been very chaotic in terms of handling and tracking materials, just because there are long lead times on parts," explained Beard. "Often, there are multiple contractors involved and many different hands in the pot."

To overcome that obstacle, JV Driver turned to Bentley and Intelliwave Technologies to create a solution that would allow them to complete projects using fewer workers than usual. In response, the two software companies developed a site management tool that integrates Bentley's ConstructSim workface planning software with Intelliwave SiteSense® RFID sensor technology.

SiteSense collects (radio-frequency identification) RFID tag data thousands of times per tag per day by installing vehicle readers onto operational forklifts and other construction equipment, which allows continuous reading of the RFID tags within 1,000 feet of each tag as the forklift performs its daily duties. This tool allows tracking, managing and installation of pipe and other tagged equipment pieces and helps crew foremen lessen redundancy and rework.

"As an industry, we need to continuously improve productivity. New technology can help with this substantially," W.E. "Bill" Elkington, chairman of JV Driver said. "We find SiteSense has a significant impact on the ability of the project to know where all of its materials are at any given time, and to locate that material effectively. This reduces material handling costs and improves tool time and productivity."

Measuring the Benefits

In 2008, the Construction Industry Institute (CII) examined the number of indirect man-hours (not related to actual tool time, such as building the plant) saved by the use of RFID. Using boiler management as the reference point, the organization found that the average worker using manual systems spent 40 minutes searching for each of the 1,000 parts that are used to make a boiler. Those using RFID took just four minutes to locate each part.

"Inefficiencies in materials management during construction can delay the start-up of a new facility, and the daily loss in production due to a slipped construction schedule can result in mega cost over runs, Beard said."

When assessing the progress JV Driver has made by leveraging innovation, Beard said owner buy-in has served as a key ingredient in the initiative's success.

"When an owner takes it under his wing and really supports the technology as a key priority for their project, the more the EPCs and contractors buy into it," he said. "This is important because if there's no buy in at the lower levels with the users, then essentially you've bought a technology that's going to be shelved."

In discussions and project work with

industry leaders in the midstream oil and gas construction industry, we have identified five areas construction firms must focus on to remain competitive in the future:

Standardizing and Integrate processes: More often than not, we see midstream oil and gas construction firms grappling with a multitude of project delivery models, tools and inconsistent reporting and billing mechanisms – all of which render daily business activities extremely challenging. Consequently, oil and gas construction firms must start looking into standardizing, codifying and documenting project management practices across the organization.

This approach to standardization doesn't necessarily translate into one single project delivery method, but rather a portfolio of consistent processes for managing different types of projects across the firm.

Matthew Pfohl, executive vice president at Sopris Systems, said a big challenge is getting "15 to 20 different project delivery models and leaders to agree on consolidating business practices into three or five methods."

"Although implementing enterprise applications is a critical step, business process re-engineering and organizational change management practices are essential – it's not as much totally redefining and restarting processes," he said. "It's really understanding best practices within the organization and trying to build standardization and automation around them."

Standardization is also a key step toward streamlining processes and improving communication and collaboration – critical for managing construction projects. Now is the time to plan and invest in collaborative web and mobile-based technology platforms that can take advantage of connectivity delivered through cloud-based applications. Having the ability to deploy and use interoperable technology applications can dramatically improve interactions between the job site and back-office operations while also improving overall company performance.

Getting serious about IT budgets: The construction lags behind other industries in technology adoption by a fairly wide margin. A recent study conducted by JBKnowledge, in partnership with CFMA and Texas A&M University, found "over 30% of construction companies surveyed said their 2014 IT budget as a percentage of 2013 corporate revenue (not building volume) is less than 1%."

James Benham, co-founder and CEO of JBKnowledge, added that 40% of survey respondents didn't even have an IT department.

"That's like letting a high school student operate as your CFO," he said. "Deep down, most industry executives don't take technology seriously because they don't believe that it delivers real return on investment."

Take a serious look at your company's technology infrastructure and lead from the top in technology adoption.

Make clear to your employees that you value technology as a critical long-term investment that will shape the nature of your business in the future. Start by forming a real IT department, assign a realistic budget, hire professionals and then include those team members in key strategic conversations.

If you can't afford to hire full-time staff, find a technology outsourcing company that can provide advisory and application services that help serve your business, such as building information modeling (BIM), material and equipment tracking.

Rethinking talent pipeline: The recent expansion of the U.S. oil and gas industry coupled with the retirement of many experienced supervisors is causing overstretched construction firms to rethink their recruiting, training and succession plans. Successful companies are developing comprehensive construction management training and knowledge transfer programs, shifting knowledge from senior and soon-to-be

retiring employees to the next generation and leveraging organizational expertise and best practices across the business.

FMI recommends searching outside the industry for those with solid business, leadership and finance experience.

"Instead of recruiting engineers, consider recruiting business school graduates or construction management graduates," said FMI consultant Dustin Bass. "We need project CEOs – individuals who possess the business acumen to run a substantial portion of work, manage and lead a workforce such that they can achieve their maximum potential – no matter the size and scope. That said, these types of employees will need an in-depth understanding of the construction business and knowledge of how to increase productivity and performance."

Building next generation's leadership: Fast-track leadership programs are becoming critical as experienced craft workers move into leadership and mentor roles, with training of less experienced employees occurring within a very short time frame.

"With the limited amount of skilled labor available, we took many of our company's highly skilled craftsmen and turned them into supervisors to help manage less experienced workers," said one industry executive. "These skilled craftsmen went from being welders one month to foremen the next month. This doesn't necessarily mean they're good quality supervisors; leadership and mentoring skills are very different from technical expertise."

Intentional and individual development of a leadership candidate pool ensures the necessary talent is available and at the highest level of preparedness when called upon. Just as the organization must develop a long-term vision, those individuals need to work toward a long-term development goal that yields a return on investment for leadership and responsibility preparation.

Understanding incremental economics: A highly competitive landscape has transformed standard estimating procedures into a game of marksmanship. Understanding the total costs for each project with a picture of how the costs break down are the first steps in knowing where and how you can improve profit margins. Having a solid hold on construction costs, fixed-wage regulations and subcontractor and supplier rates is also important, both from a qualified bidder standpoint and from a strategic standpoint.

In another vein, deep knowledge of estimating can provide you with new ideas for being more productive and alert you to early warning signals that subcontractors might be in trouble. Understanding the risk brought on by your subcontractors and your employees has become a critical responsibility in today's risk-averse oil and gas construction industry.

Conclusion

As companies have discovered, innovation is a key requirement for leading construction firms looking to break out of the traditional ties that bind them to mediocrity within the industry. With almost two-thirds of the typical project costs spent on materials and equipment, and the remaining 30-40% allocated to labor, construction firms have to tighten up their operational strategies and procedures or risk being left behind.

As the U.S. midstream oil and gas construction industry continues to post impressive growth, everything from high cost overruns to delayed projects to declining productivity will take a toll on bottom lines. By focusing on key metrics like the productivity formula, and by embracing new, technology-centric methods and strategies, companies can implement groundbreaking business practices not thought of previously.

This, in turn, will help the most progressive midstream oil and gas construction firms improve productivity and manage costs in today's extremely competitive, labor-constrained business landscape. ***P&GJ***

Oil and Gas Research: Eyeing the Future, Bridging Gaps

By **Richard Nemec,** Contributing Editor

SwRI's Multiphase Flow Facility is being used to evaluate the performance of scrubber internals for the Separation Technology Research (STAR) Program. Testing is conducted at field-like conditions, including elevated pressure with hydrocarbon gas and liquids. (Photo courtesy of Southwest Research Institute).

In the gridlock of first-quarter 2015 earnings conference calls last spring, Doug Suttles, CEO at Alberta-based Encana Corp., talked bullishly about the Canadian energy company's production growth prospects.

Suttles

This while in the midst of reporting a $1.7 billion loss for the quarter tied to a $1.2 billion impairment charge brought on by last year's global oil price crash and another $500 million of red ink coming from a foreign exchange loss. Regardless, Suttles couldn't have been more upbeat when he talked to analysts in mid-May.

The reason for his optimism emanated from Encana's scaled-down portfolio emphasizing two U.S. shale plays (Permian and Eagle Ford) and two in Canada (Montney and Duvernay), and the compa-

ny's ability to apply continuing technology advances to increase its drilling efficiency and cost-savings even in a low-price environment.

"I think the biggest single driver is innovation, doing things smarter and better," Suttles told the conference call, adding that even if there is a big increase in prices and oilfield production activity, the savings from innovations will stick. They're good at $100 or $50 oil, he said.

If there is a theme to current research and development efforts across the oil and natural gas sector, it is that unconventional is today's conventional, along with growing regulatory and economic focus on safety and environmental concerns. The R&D playbook has shrunk while its plays get more complex, not unlike Encana's current operating playbook.

Now that the shale revolution is in full bloom, perhaps not enough of the industry or general public appreciate the years, millions of dollars and the public-private sector sweat equity that helped make it a reality. The late George Mitchell and his fellow pioneers on hydraulic fracturing had a lot of help from both government and private sources, veteran researchers at places like Illinois-based Gas Technology Institute (GTI) will explain to anyone wanting to take the time to listen.

But that hard-fought, long-time coming success has spurred even more R&D today, which forms the basis of the innovations and efficiency gains that are being achieved on a regular basis in all of the major shale plays. Efforts to cut fracking's water use, apply LNG to fracking jobs and perfect the reinjection of carbon dioxide are just some of the examples industry researchers are examining to make tapping unconventional resources even more routine and productive in the years ahead.


Buckingham

And away from well sites there is plenty of action in areas such as developing new natural gas compression technologies for transmission pipelines, or perfecting the emerging new technologies for monitoring and testing those pipelines without interrupting the flow of gas. These projects are being done by and for industry collaboratives and individual companies. The Southwest Research Institute (SwRI), for example, has a group of projects ongoing related to evaluating various leak-detection technologies for both liquid and gas pipelines, underwater and underground, said Chris Buckingham, a SwRI manager based at its headquarters in San Antonio.

Much of the focus comes from the recent history of both the energy industry and the nation's political landscape. Obama administration initiatives to significantly cap and cutback methane emissions from all parts of the fossil fuel chain can be attached to many of the major focal areas of the Pipeline Research Council International's (PRCI) lineup of $10 million of annual R&D projects. PRCI President Cliff Johnson previewed a "methane emissions roadmap" the research council was expecting shortly.

"There is a lot of misinformation out there on all sides," Johnson said. "We're trying to figure out what is the best way to survey and understand what is going on."

PRCI and many of the other R&D organizations that were contacted by *P&GJ* for this article are really in the business of giving the energy sector new tools. And they have potential to have operational, environmental and economic impacts. When they hit a home run, all three can be achieved.

In general, innovation has come from the operators on the ground, backed by ongoing projects in the labs and through field tests. Amidst the U.S. pipeline system, including compressor stations and other equipment,

Columbus, OH-based Battelle Memorial Institute assists operators, service providers and vendors in assessing significant problems that may arise.

"We come in and do a full soup-to-nuts deep dive into their operations to determine the sources of their problems, such as operational testing, material sampling or material testing. Then we make recommendations for improvements and mitigation steps while designing guidelines to avoid the problems from happening again," said Battelle's spokesman T.R. Massey.

With industry and company backing, organizations like Battelle also look at more arcane issues and questions, such as a current application of "computational fluid dynamics" (CFD) in seeking a better understanding of minute (nano-pore scale) shale gas flows. To do this, two Battelle researchers in Columbus, Srikanta Mishra and Michael Swickrath, have teamed with a Texas A&M University researcher, Akhil Datta-Gupta, to use CFD modeling in image analysis using reservoir simulators.

The driver for the project, the researchers explain, is the fact that shale gas pore structure has what they called "a wide distribution of pore sizes and shapes," including micro- and nano-pores. If more effective permeability measures of shale are developed, it will have important benefits for simulation-driven performance predictions, fracture design and enhanced oil recovery (EOR) applications, the three researchers explain in their abstract, *CFD Modeling of Nano Pore Scale Gas Flow in Shales*.

Industry focus understandably is on getting products, processes and tools into the commercial realm, therefore organizations such as GTI, Battelle and PRCI leave basic research for the universities and specialized think tanks, or to some degree government operations, such as the Department of Energy (DOE) and its affiliated laboratories. There is in the energy R&D sector a focus on helping projects overcome what researchers commonly call the "valley of death," the abyss into which many efforts plunge, trying to get from pre-commercial to commercialization.

"If you were to define GTI it would be as an applied research organization," said Ron Snedic, the institute's vice president for corporate development. "We're taking things from the lab into the marketplace, shepherding it from the valley of death where it works in the lab but people aren't buying it, and making it into a universal product. We really focus on getting projects through the valley."

A 23-company collaborative managed by GTI, Operations Technology Development (OTD), over the last 12 years has placed over a dozen products in the marketplace covering pipe leaks, materials, repairs and rehabilitation, excavation/site restoration, pipeline integrity management/automation, operations infrastructure support, and environmental/renewables/gas quality solutions. Firms such as Mainline Control Systems, SENSIT Technologies, LocusView Solutions, Integrated Tool Solutions LLC and ULC Robotics have put products into the industry mainstream as a result of OTD-backed work by GTI.

"In recent years, OTD has not only helped to introduce several new products, but has also supported the establishment of information websites and guidelines," said Charles Shafer, immediate past chairman of the OTD board in its most recent annual report. "Our technology is entering the marketplace, providing valuable services through companies including LocusView, which provides mapping and survey services to track and trace company assets."

The focus of GTI's subsidiary, LocusView, is indicative of today's emphasis for using technology to capture real-time data in the field, link the asset information to GPS coordinates and upload that information into the company's geographic information systems (GIS) through tablet computers

From Mars to Earth – Heaven Sent Technology Advances

Three years ago as NASA landed a space-age dune buggy on Mars, NASA engineers carefully developed a methane-detecting "sniffer" as a means of enabling the unmanned rover to test for potential life on the red planet through the presence of CH4 (methane's chemical composition).

Called a "tunable laser spectrometer," the technology has been brought down to earth by NASA's Jet Propulsion Laboratory (JPL), which is working with San Francisco-based Pacific Gas and Electric Co. (PG&E) in developing a smaller version that can be used in leak detection along major expansion of transmission and distribution pipelines. It's a chance to save money and improve safety for PG&E's Francois Rongere, manager of research, development and innovation.

Industry analysts like Housley Carr, at RBN Energy LLC, are predicting big things for drones with the Federal Aviation Administration (FAA) loosening up restrictions for some civilian applications and making the energy industry a high-priority potential user. In fact, Carr wrote last spring that "drones are getting involved in just about everything – geologic mapping, site surveying, methane detection, pipeline inspection, you name it."

Combining a miniaturized version of the JPL-refined technology with light devices such as unmanned aerial systems (UAS), or drones, has the advantage of more precision in spotting leaks and doing it with a very light, small-scale technology, according to Rongere. "It gives us high precision to find leaks and fix them quickly," he said. "With UASs we have something that is both light and sensitive."

In California it is a three-part effort underway, with JPL as the inventor of the sensor helping to miniaturize it further, a laboratory at the University of California Merced campus providing a host of drones for various applications, and PG&E providing the field testing. On a national and international basis, the parties are working under the umbrella of PRCI and some of university work at Merced is tied to NYSEARCH, the Northeast Gas Association's R&D arm.

Tested on the ground in 2015 through use of PG&E field technicians at the combination utility, the technology's integration with drones is scheduled to happen in mid-2016, said Rongere, noting that on a parallel track, FAA should have a final set of regulations for commercial deployment of UASs by late 2015 or early in 2016.

While he won't give specific numbers on cost savings, Rongere said the drone deployment obviously can save a lot of time and money "by finding more leaks and finding them faster at a reasonable price." And if PG&E and other operators spend less on leak surveys, they can do more of the surveys, and that should enhance safety.

"This is something the company wants to do – increase the frequency of leak surveys, and the reduction of costs will, in fact, drive more surveys," he said.

In addition to the obvious applications to pipeline systems, Rongere added the technology can be used with compressor stations, too, and in that way help expand the industry's response to the Obama administration's call to reign in methane emissions nationally to mitigate future climate change effects.

Even in its current state of infancy, drone applications for private industry are getting on everyone's radar. RBN Energy's Carr noted the FAA as of May had already granted over 400 approvals for commercial drone flying, with tight restrictions, such as staying within an operator's "visual line of sight" (VLOS). He cited FAA as considering allowing some drone use outside VLOS.

"[FAA] is working with BNSF, the railroad giant with big crude oil-by-rail shipping, on using drones over long distances in rural and isolated areas to inspect rail infrastructure," Carr wrote in his blog report. ■

– Richard Nemec

and smart phones. These technologies and services will help companies comply with regulations and cost-effectively manage the enormous amount of data that they will be gathering and maintaining.

Battelle's Massey said a commercial operation spun off of the institute, Winner Water Services, is an example of the research organization putting up the funding to take its technology from the laboratory to the commercial stage. With help from DOE and Pennsylvania state funding, Winner Water developed a means of cleaning up hundreds of millions of gallons of polluted water called "acid mine drainage" (AMD) that exists in and springs out of abandoned coal mines daily and makes it available to shale oil and gas producers for use as fluid in fracking.

That's another example of the research organization nurturing a product through the valley of death syndrome.

When asked for Battelle's major focal points in 2015, Massey lists four:

- High-pressure/high-temperature materials resistant to hydrogen sulfide (H2S) and solvents (polymers, lubricants), as well as advanced corrosion detection and mitigation technologies;
- Computational modeling of injections for hydraulic fracturing optimization and wastewater disposal to maximize storage capacity and minimize effects such as induced seismicity.
- Data analytics to help optimize exploration/production/operations for oil/gas companies.
- Analytical chemistry methods for hydrocarbon fingerprinting for environmental monitoring, as well as "metagenomics" (genetic material recovered directly from environmental samples) for biodiversity assessment.

The lists from GTI and others cover different areas, but those research organizations also want to respond to the operational and environmental demands embedded in the current energy landscape that has been shaped by the shale boom.

Much of the research involves refining existing processes and systems that are aiding the growth of the U.S. energy sector into a world leader. At PRCI, researchers are focused inside of energy-carrying pipelines to find better ways to enhance the reliability of those steel arteries feeding factories and homes.

At GTI, researchers are looking intently down the horizontal borehole at each stage of the hydraulic fracturing process, seeking to expand the productivity and efficiency of each of those stages. And among the varied projects at SwRI are attempts to refine the reinjection of carbon dioxide (CO_2) in the oil and gas production fields as a third option in EOR operations and also in the long-sought search for a magic bullet for commercializing large-scale carbon capture.

"From a GTI perspective, in our upstream work, we're predominantly focused on onshore, unconventional gas," Snedic said. "Nearly everything that GTI does further tightens that boundary, focused on environmental impacts and productivity improvements."

His example is a DOE-funded $7 million program with total funding of $10-20 million over two years, building out a hydrofracking test site. The purpose: substantially improve the production attained along each zone of a hydraulic fracturing job.

"What we are looking to accomplish with our partners is to find a way to optimize and maximize the production on all of the zones, which might mean treating each zone differently," Snedic said.

Set to get underway later this year, he calls it a "very exciting project" in which GTI has entered its third phase. After designing it and completing a preliminary study, it is now entering the action phase, he said. It will be field-tested west of the Mississippi, perhaps in the Permian Basin.

The research institute also has formed

a company, LocusView Solutions, to support the commercialization of advanced geospatial technologies in the gas industry. One of its applications is in tracing the electrofusion of plastic pipe, ever-more common in distribution pipeline systems around the nation.

"This is another area, broadly speaking, that is going to be a game-changer for the gas industry," said Snedic, noting it gets at the recordkeeping conundrum for major utilities.

"How to gather and handle all of this data, how to manage it, and ultimately how to do something useful with it" is the challenge," he said.

In contrast to GTI's role, Snedic said basic research "is way, way out; most of the projects we do here are more practical in their application." He noted that even the grants from DOE's Advanced Research Project Agency for Energy (ARPA-E), which focuses on highly transformative solutions, have relatively short timelines associated with the work.

"There is a very intimate relationship between the industry and our researchers," Snedic said. "The reason that OTD works is because the industry is very engaged with us identifying priorities and what their focus is, and then working with us in project groups. Our members are involved year-round."

Johnson has a similar relationship with a smaller cadre of industry members at PRCI, engaging collaboratively within his organization and among the other industry research centers.

"We've seen a shift in the tools that are available to note characteristic changes from one pipeline segment to another," he said. "We do see those tools coming to the fore, and if they become a reality, it will be a huge step out for the industry."

Similarly, Johnson sees a lot of advancements in rights-of-way protection and monitoring so any threats can be picked up and addressed more quickly. This is ground-based, aerial-based and employs the use of satellites in some instances. (*See related story.*) The Federal Aviation Administration (FAA) in the past two years has begun to authorize the use of drones for monitoring various energy corridors in California, Colorado and elsewhere.

In some cases, the research can be focused on creating new and better tools for testing and refinement of future processes and equipment. At SwRI, researchers are looking at various aspects of separation technology as a means to separate oil, gas and water, or some combination of them.

"In general, the industry doesn't have a lot of data on these products or the components of these productions in field kinds of conditions," said Buckingham.

As such, SwRI is trying to develop some standardized testing procedures and capabilities where operators can capture data on different internal components under real operating conditions, he said. "So when they go to design separators to operate under these conditions, they'll have some data to better predict the performance. Right now, their prediction is based on air and water data."

It is in the interest of the large operators, like ExxonMobil, to have equipment makers more aware of the performance of their equipment under real-world field conditions, so the SwRI team is hoping this project will drive new technology development to create better products that perform well and hold up in field conditions both on and offshore.

Similarly, Buckingham's colleague at SwRI, Klaus Brun, machinery program director, outlines the testing of LNG as a fracking fluid, high-pressure proppant mixing, CO_2 and sour/acid gas reinjection studies, and wet gas compression as a myriad of research efforts, all of which are tied closely to their potential future value in the field.

"Normally, when you make LNG, you

have to maintain a fairly high quality by removing water, CO_2, etc. from the gas," Brun said. "In this particular case, it is probably not necessary, at least to take all of it out. We need a rough [as opposed to refined] LNG process, and then you have to take the LNG to whatever the fracking pressures are [10,000 psi, etc.].

"So, we're looking at various top-side processes to produce LNG at reasonable costs. Since LNG requires a refrigeration process, there are several refrigeration approaches – straight refrigeration, or the Joule-Thomson effect, and there are various approaches. We're trying to find the right hybrid process."

Brun explained that part of the challenge is determining how much CO_2 should be removed from the wellhead gas. "CO_2, when you cool the natural gas down, forms dry ice that can plug piping and valves with crystal CO_2. So we are going to have to remove some of the CO_2 and do something with it before you reinject it."

SwRI is doing the project for DOE in partnership with Schlumberger, Brun said.

PA-based Battelle subsidiary Winner Water Services opened a facility in 2014 near Pittsburgh that treats acidic drainage seeping from a long-abandoned coal mine so it can be used as source water for hydraulic fracturing. Last month Gov. Tom Wolf signed a law for the use of treated mine water in natural gas drilling operations.

The project was kicked off in early 2015 as a three-year $2-3 million undertaking.

Brun and the SwRI exudes the state of today's industry-wide research, focusing on physical properties and processes working with industrial and energy industry giants from GE to Siemens and Solar Turbine, pooling financial and intellectual resources, all to keep pushing forward.

Even in the midst of depressed global oil prices and whittled down capital budgets, no one is suggesting that R&D efforts should not remain robust. The future involves forward moving, forward thinking. There is no turning back. ***P&GJ***

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Hard Decisions for LNG Project Developers

By **Larry Persily**

The frustrations of an oversupplied LNG market and low prices were evident as about 100 liquefied natural gas buyers, sellers, lenders, advisers and goods and services suppliers gathered in London earlier this fall.

"How do you plan your business in an environment like that," said David Ledesma, managing director of South-Court Ltd., a UK-based oil and gas consultancy. "How are you going to go out and make final investment decisions?"

Spot-market prices for LNG cargoes delivered to Asia this fall are down two-thirds from the record $20 per million Btu in February 2014. Demand in China is not growing as much as was expected — just as new supplies are coming online from Australia and the United States — creating fears of an oversupplied market and low prices for several years.

Meanwhile, buyers are demanding shorter terms and more flexibility in their LNG supply contracts. Speakers at the fifth annual LNG Global Congress Sept. 23-24 said the oversupply could play itself out by the 2020s, creating opportunities for new projects to meet demand, but those investment decisions are getting tougher on LNG project developers.

"Gone are the days when you can expect to get 15% return on your LNG plant," said Mike Fulwood, a principal in Nexant's global gas consulting practice.

Low Prices Will Help Build Demand

Conference speakers noted the price for LNG was way too high a couple of years ago but now it is far too low. The price needs to stay low enough to continue attracting new customers - which, the theory goes, would lead to increased demand and somewhat higher prices. That means producers will need to hold down costs for new projects if they are to make money in the low-price world.

"The industry needs to find new ways to get lower costs," said Thierry Bros, senior European gas and LNG analyst for Paris-based banking and financial services company Societe Generale. "If you want to increase demand, you decrease prices."

Kazumi Takahata, deputy general manager at Tokyo Gas, had the same message: Keep the price down and we'll buy more. In addition to lower prices, Japanese utilities are looking for a more diversified supply portfolio, he said, listing North America (including Alaska), Russia and East African nations as potential suppliers.

A conference poll showed a strong majority believe LNG prices will stay below $10 per million Btu (roughly 1,000 cubic feet of gas) through the end of the decade. Although $10 would be a big increase from the $7 range sellers received for spot cargoes in September 2015, it's still a long way from the highly profitable prices of 2012-14 that averaged over $15.

LNG Trade has Changed

"We had this impression that the good times would never end," said Vivek Chandra, CEO of Texas LNG, a smaller liquefaction project proposed for the Texas coast. "Instead of feeling sorry for ourselves, we need to embrace change."

LNG markets used to operate in their own tradition-bound world of long-term contracts between a limited number of buyers and sellers. Now the market is behaving like any other commodity, Chandra said. Supply and demand dictate price and price determines customer decisions.

"When I buy chocolate, I look at Swiss or Belgium. … When I buy gas, I look at the price," Bros said. Gas is a commodity, and there is nothing special about one country's LNG over another. Bros said he stressed that point when he told a group of Canadians recently that their LNG is no better than anyone else's and they should not expect a premium price. Developers are promoting two dozen LNG export plants on Canada's western and eastern shores, though none have committed to construction.

The risk, many of the conference speakers said, is that developers of LNG export projects will shy away from final investment decisions (FIDs) this decade, setting the stage for supply shortages in the 2020s.

New Markets Developing

"Looking ahead, the current situation might delay FIDs and set the basis for the next cycle (beyond 2020) where demand grows faster than supply," said Carmen Lopez-Contreras, senior analyst for the gas and power planning team at Repsol, a Madrid-based global oil and gas company. Lower prices will accelerate demand in new markets, she said, pointing to Pakistan, Jordan and Egypt as examples. "We have this amazing (demand) growth in Middle East countries that we have to watch." Mideast countries are increasingly turning to natural gas for power generation rather than burning oil products.

In addition to the Middle East and Pakistan, growth markets are building in Southeast Asia (particularly Thailand), the Baltic region and Latin America, said Matthew Monteverde, vice president for

generating fuels at Argus, a global energy news service.

The lower-cost and relatively quick development time (months, not years) for floating import terminals - ships that offload the cargo from an LNG carrier, store it, regasify it and pipe it to shore-based customers as needed - is making it easier for more countries to sign up for LNG deliveries.

Several speakers, including Stephanie Wilson, managing editor of the Asian LNG team at Platts news service, repeated the possibility of a tight market by 2025 if not enough new supply is developed. It won't be easy for developers to make investment commitments for new supplies. More buyers are demanding shorter-term contracts of three to five years, she said, with diversified pricing to replace the traditional LNG price link to oil on an energy-equivalent basis.

"We know there will be shortages in the future because FIDs are not being taken," said a senior adviser to a multinational oil and gas company. The deterioration of traditional long-term, take-or-pay contracts and the growth of shorter-term deals - with buyer flexibility to redirect or resell the cargo - is "uncharted territory," he said.

Therein lies the conundrum.

"The banks still will need a long-term offtake from a creditworthy customer," said Ian Catterall, senior vice president and head of natural resources at the Bank of Tokyo Mitsubishi. "Good projects will always be financed. I'm not sure which projects are the good projects."

Conference speakers raised several other topics:

- LNG imports have gotten so cheap for China that the average prices are less than pipeline gas deliveries from Central Asia, Platts' Wilson said. Meanwhile, smaller, private buyers are gaining access to China's LNG terminals controlled by the nation's biggest importers, providing a new market for more import cargoes.
- India will take an increasing volume of LNG as long as prices are low, Bros said. The government holds down the retail price of natural gas, putting pressure on importers to avoid high-cost contracts. India's main LNG importer is pushing Qatar to negotiate lower prices on a long-term contract that dates back to 2004.
- China wants to develop its substantial shale gas resources, to help reduce its reliance on imports, but "that's moving much more slower than the official plan," said Victor Perez, partner at consultancy A.T. Kearney's energy practice. Geology and a lack of technical expertise are the hurdles.

85% of Planned Projects Doomed?

Meanwhile, a report from Bloomberg said that "85 gas projects are endangered by today's low-price environment." An Oct. 8 article noted that five years ago, energy companies began planning as many as 90 terminals to send natural gas around the world. Now, it seems the world only needs five more, the report said.

Consulting firm IHS Inc. says only one in every 20 projects planned are actually necessary by 2025 as weakening Asia economies, cheap coal, the return of nuclear power in Japan and the ever-expanding glut of shale supply in North America temper demand for the power-plant fuel, putting tens of billions of dollars worth of export projects at risk.

Barring an unusually cold winter in Asia, global LNG supply will outstrip demand by next year, Trevor Sikorski, an analyst at Energy Aspects Ltd. in London, told Bloomberg. Seven new plants in Australia will flood the market over the next two years. Cheniere Energy Inc. is planning the startup of its Sabine Pass terminal in Louisiana this quarter.

"The global LNG industry now resem-

bles a game of 'musical chairs' with far more projects than the market can absorb," said James Taverner, an IHS analyst in Tokyo. "There is a very narrow window of opportunity for new projects that want to take final investment decision by 2020."

Four years ago, the International Energy Agency predicted global demand for the heating and power plant fuel would climb 16% by 2016. Now, it's projecting 11%, and terminal developers are taking note. Excelerate Energy LP's floating terminal in the Gulf of Mexico has been postponed. Inpex Corp. delayed the start of an LNG project in Australia by almost a year to the third quarter of 2017.

"It will be increasingly difficult to convince financial institutions to put major sums of money on the table to construct additional capacity," Tim Boersma, acting director of the Energy Security and Climate Initiative at the Brookings Institution in Washington, said by phone.

North America

Over half of the 38 terminals proposed for the contiguous U.S. may never be built, according to Fitch Ratings Inc. and the Brookings Institution, a nonprofit research group. Besides Cheniere's Sabine Pass, projects in development include Freeport LNG Development LP's terminal in Texas, Dominion Inc.'s Cove Point in Maryland and the joint Lake Charles LNG venture in Louisiana between Energy Transfer Equity LP and BG Group Plc.

Twenty more terminals are planned for Canada, according to Energy Aspects, including the Kitimat project proposed by Chevron Corp. and Woodside Petroleum Ltd. in British Columbia. The higher costs associated with projects there, in part because of environmental opposition, makes it even less likely that they'll be built, Jeffrey Currie, head of commodities research at Goldman Sachs & Co. in New York, said in a Sept. 24 interview.

This deluge of North American gas exports was once seen as displacing some foreign supplies linked to the price of oil. Then the oil market crashed and crude lost half its value, and now that gas from abroad is looking cheap.

The pace of project postponements will pick up as the supply glut expands, Noel Tomnay, head of global gas and LNG research at Wood Mackenzie in Edinburgh, said in a Sept. 3 report. Development of even half of the capacity may keep the Asian market oversupplied through 2025, he said.

Australia's Gas

While the U.S. LNG projects already under construction will probably come to fruition, any supply not already contracted will be difficult to find a home for, particularly in Asia where Australian gas is easy to get, Currie said.

Spot LNG prices for delivery to Northeast Asia have slid 56% over the past year, according to data compiled by *World Gas Intelligence.* Shipments to Japan will average $5.80 per million British thermal units in 2015, a 65% decline from 2013, according to Energy Aspects.

The world's demand for gas, meanwhile, expanded by only 0.4% in 2014, the smallest gain since 2009, because of shrinking imports to Japan, South Korea, India and China, Bank of America said in an Aug. 21 note to clients.

"Given the price environment and the supply that's going to come online in the next five years or so," said Dino Kritikos, an analyst at Fitch in Chicago, "many of these projects are at an inherent disadvantage." ***P&GJ***

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Mastering the Inspection of Challenging Pipelines

By **Dr. Michael Beller, Tom Steinvoorte, Stefan Vages, ROSEN Group**

Any inspection device used internally must be introduced into the pipeline to be investigated. This implies that the line is accessible. "Piggable" lines need suitable launchers and receivers and are generally inspected in a unidirectional mode. If tool traps are not available or suitable, access has to be achieved via other means. Accessibility can be achieved through technical and/or procedural means.

One solution may be the use of temporary traps, another to use a hot tapping operation. Then again, procedures can be developed to use a given flange or any other access point, for instance a valve, as a point of entry. Tools can also be designed to allow for single access, i.e. entering and leaving the line at the same location. In this case, a bi-directional tool and appropriate procedures must be utilized.

Accessibility Example 1:
Accessing a Line Using a 3-Port Valve

The mission of this project was the inspection of a number of 10" flow lines transporting a multiphase medium consisting of oil, water and natural gas to a gathering line.

There were no launchers and receivers and it was not feasible to install them, even temporarily. The customer required an internal inspection ensuring full coverage of the pipe wall. The only available access to the line was specialized three-port valves which had originally been installed to launch cleaning scrapers.

The special requirement in this case was to modify an inline inspection (ILI) metal loss survey tool in order to fit into the very confined space of the three-port valve, see Figure 1. In addition, a launching-and-receiving procedure had to be developed to ensure that the ILI tool would safely enter the line and could also be safely retrieved.

In order to ease the actual introduction of the tool into the valve a special metal cage was designed into which the tool could be preloaded. Then the entire cage was introduced into the valve, locked, and the valve closed. From here the tool could be launched safely and then the cage retrieved. For receiving, a similar device was used at the downstream valve into which the tool traveled, was stopped, and could then be retrieved.

A very important and indeed critical aspect was the tool tracking during the inspection, especially as the tool approached the receiver. It was of great importance to be able to detect the tool approach and measure it with high precision to ensure that the tool`s final approach could be controlled and stopped at exactly the location of the valve.

Figure 2: Bi-directional MFL tool.

Accessibility Example 2:
Offloading Pipeline Inspection

The project related to a 20" offloading line used for transporting jet fuel from a multi-buoy mooring position via a PLEM (Pipeline End Manifold) to a beachhead area. The major challenges were that no tool traps were available and the inspection required a subsea entry into the line. It was a requirement that the process not interfere with normal offloading operations, full coverage of the pipe wall was ensured, only clean product reached storage, and no contamination of the subsea environment would be accepted.

The solution consisted of using a specially designed bi-directional, low-friction MFL tool in combination with an optimized cleaning program. Tailor-made procedures were developed for the project, including the design, provision and installation of a subsea launching spool. The project included modification of the PLEM to allow disconnection of submarine hoses and installation of the launching spool without

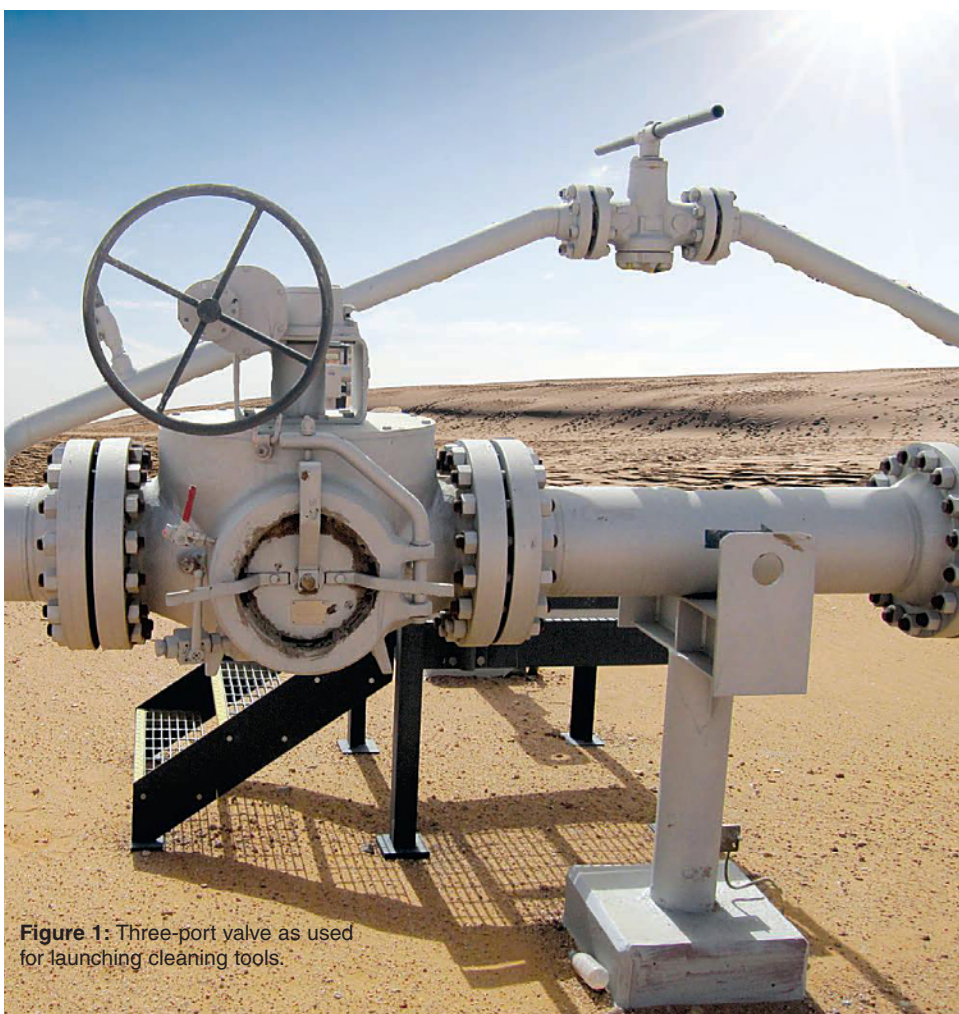

Figure 1: Three-port valve as used for launching cleaning tools.

impacting the subsea environment.

The pipe spool was installed with drains and vents between the PLEM valve and the submarine hoses for product recuperation before hose removal. The temporary receiving trap was fitted with a filtering system to ensure that only clean product was sent to the storage tank. The final design of the launching configuration and associated procedures enabled launching of the cleaning and MFL tool without intermediate spool recovery.

The clear benefit to the customer was a high-resolution inspection of the offloading line not possible with traditional ILI, but still providing quality data for integrity assessment purposes. The procedures developed ensured job execution with no impact on normal operations of the line.

On the Issue of Negotiability

The term negotiability addresses whether an inspection device can get through a line. Hindrance of achieving this may be due to the mechanical design of the line or the operational conditions during the inspection. The former relates to items such as tightness of bends, type of bend – for instance mitre bends – diameter variations, installations that need to be passed, such as wyes or unbarred T-pieces. The latter addresses issues such as low flow, low pressure or the opposite of particularly high pressures or flow and temperatures. In short, those operational conditions which may not allow use of a traditional ILI tool.

Negotiability Example 1:
Ultra Low Flow Inspection

The project was to inspect a 16" onshore gas pipeline during normal operation. The challenge resulted from the operational conditions during the inspection. The pipeline is used to feed several customers through various offtakes distributed along the route. Toward the final offtakes the flow velocity reduces to values around 0.1 m/s. A high-resolution MFL inspection was required, providing full coverage at a pressure well below requirements for traditional ILI.

Here, the solution concentrated on designing a customized pull unit which provided optimum sealing throughout the inspection and thus ensuring no risk of bypass. With the prevailing low flow the latter would have invariably resulted in stoppage of the tool. In addition to the sealing issue, a low-friction magnetizer was used to minimize friction during the run.

Due to the low travel speed, it also had to be ensured that the onboard power supply was capable of handling the run time. This was achieved using a modified pull unit housing extra batteries. High-quality data was collected utilizing advanced Hall sensors with no lower speed limit. An eddy current-based system was used to differentiate internal and external features.

Special procedures were devised in order to mitigate any risks regarding the low-flow conditions, including a "kicking" option, i.e. depressurizing the line downstream of the tool, if necessary. A specialized pipeline data logger was included to record differential pressures during a gauge tool run in order to gain a full understanding of operational conditions prevailing in the line during inspection.

One major benefit to the customer was that the inspection did not impair with the routine operation of the line and high-quality inspection data was obtained.

Negotiability Example 2:
Low-Pressure Pipeline Inspection

A 10" natural gas pipeline needed inspection. This line is part of the installation of a depleting sour gas field running at a pressure of approximately 10 bar (145 psi).

The requirement was to inspect this line under existing environmental conditions. The solution consisted of a specially designed low friction MFL tool incorporating optimized sealing capabilities as well as a wheel-supported magnetizer. In addition, tailor-made procedures were implemented, including line preparation and close monitoring of the operational conditions during the run utilizing a pipeline data logger on the tool.

The major benefit to the customer was the ability to obtain high-resolution metal

loss data in an operational environment where traditional ILI tools could not be run due to the low operating pressure.

Figure 3: Low pressure or low flow can be major challenges for a successful ILI inspection.

On the Issue of Propulsion

The issue of propulsion relates to how the tool is moved through the line. In traditional ILI, the inspection devices are pumped and the propulsion of the tool is provided by the differential pressures across the driving unit. Pumping, if possible, is also one of the options for moving tools during a "challenging inspection" operation. However providing this differential pressure is the challenge if the inspection cannot be performed during normal operations.

In addition to pumping, inspection tools can be moved or retrieved through the use of special cables or so-called tethers. The cable in these cases can have three functions and any of these can be used independently or in combination.

First, the cable can be used for tool movement. This application is often referred to as a wireline service. Second, the cable can be used for power supply, and finally, it can be used for data transfer. One major advantage of cable-operated tools is that they can be stopped during the inspection to enable a stationary inspection for a specific time. This may be an advantage for a video inspection, to have a closer look, or, say, a specialized crack inspection utilizing Time of Flight Diffraction techniques (TOFD), not now possible during axial movement of the tool. The price is that tethered tools travel at much lower speeds than free-swimming tools and have limited range.

If pumping or pulling is not possible, the situation arises where a tool must have its own propulsion unit. This is the realm of robotic tools, also available in the industry. These special crawler devices move the required inspection unit through the pipeline uni-directionally or bi-directionally.

The two most important aspects relating to the use of robotic tools is to have access to the right configuration for the job, i.e., a unit providing precisely the traction forces required for a given task. If traction is too low, the tool train may become stuck. If traction is too high, the line may be damaged. The other paramount requirement is a failsafe use: what goes into the line must come out! This implies robotic tools must incorporate collapsible designs to ensure that they can be reliably retrieved in case of malfunction.

Propulsion Example 1:
Inspection of a Loading Line

The project related to two 20" loading lines transporting refined products from a vessel to an onshore terminal. A schematic of such a loading line is shown in Figure 4. The challenge consisted of having a pipeline with only one entry point. A temporary trap for launching and receiving needed to be installed, and any modifications and the subsequent inspection run had to be performed within an extremely tight schedule.

Again, the solution consisted of a technical tool-based component as well as associated tailored procedures for executing the job.

The solution included implementation of a series of modifications to the pipeline to allow for installation of the temporary trap within the complexity and space constraint at the terminal. A bi-directional gauging operation and use of a bi-directional high-resolution MFL metal loss tool were completed within the timeframe specified by the customer. The procedure consisted of launching the tools at the launcher, pumping from the terminal site until they reached the subsea Pipeline End Manifold (PLEM).

The end of inspection was controlled by monitoring the discharge pressures at the terminal pumps. A circuit was created by interconnecting both loading lines with a topside interconnection implemented at a mono buoy. In order to allow for the tools to return to the terminal, pumping was done in the reverse direction until both gauging and MFL units reached the trap, now acting as a receiver.

The clear benefit to the customer was the collection of high-quality metal loss data under complex operational conditions and within the required short timeframe. The tailor-made procedures also included a risk-minimization process, especially important as the refined product is supplying a large metropolitan area.

Propulsion Example 2:
Inspection of Storage Tubes

An operator had the challenge to determine a viable solution to inspect his storage tubes with lengths ranging from 246 to 875 m (800 feet to 2,870 feet) and wall thicknesses ranging from 13.2 mm to 25.4 mm (0.5" to 1"). The storage tubes serve as an alternate to storage caverns or abandoned oil/gas wells to store ethane, which is used in the production of ethylene products.

These storage systems enable the operator to gather sufficient product in order to ship it efficiently through their pipeline network. The challenge here was to develop a solution to inspect these storage tubes, diameters 48" and 54", from within with the precision and reliability usually associated with ILI, and without the need for personnel to be physically inside the line during inspection - the method previously used.

Obstacles that needed to be overcome were that only a single access point was available without any traps, and no flow was available during the inspection. requiring a tool incorporating its own propulsion unit for movement. The inspection requirements set by the operator were optimum probability of detection and identification (POD, POI) for internal and external metal loss as provided by free-swimming ILI tools.

The solution required development of a reliable propulsion unit to move the inspection tool through the tube, which was not available initially. For this reason, a special robotic design was utilized, incorporating a self-propelled movement technology as shown in Figure 5. This design was based on an earlier helical movement design and then extended to be used in conjunction with an axial movement technology.

The robotic technology design includes an autonomous onboard power supply, online charging, a failsafe tethering retrieval unit, visual monitoring in front and rear, accurate power consumption monitoring, and is capable of negotiating the 48-54" diameter range.

The failsafe system includes retractable yokes for the MFL inspection unit, emergency power supplies as well as a backup wireline for power, communications and evacuation.

The inspection speed was approximately 90 mph (295 ft/h). The five storage tubes which formed part of the project were inspected in September and October 2014. The data quality and quantity was assessed in the field and determined to be good. A first screening for any metal loss was performed on site, and first results could be presented within 12 hours of completion of the inspection.

A great benefit was achieving full ILI specification for a pipe section or tube considered unpiggable. Another advantage was the capability to inspect lines of different diameters with a single crawler device and achieving full coverage of the line. This included application of automated internal inspection without the need for traps; highest level of safety with no need for human personnel to enter the line; minimized risk due to the failsafe mechanism incorporated

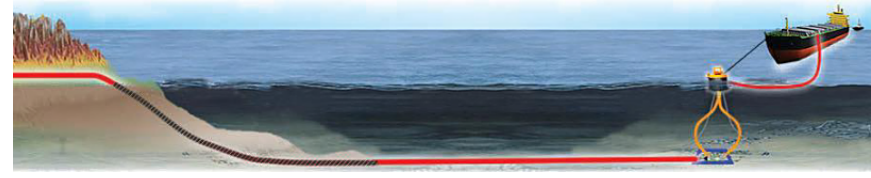

Figure 4: Schematic drawing of a typical offshore/onshore loading line.

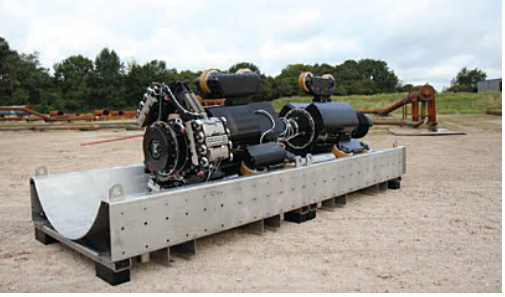

Figure 5: RoHelix, self-propelled robotic crawler.

into the design of the propulsion unit.

Piggable, Challenging or Unpiggable: How do I Know?

As demonstrated, there are a variety of contributing factors which determine whether a pipeline is piggable, challenging or truly unpiggable. Figure 6 is a flow chart intended to be an initial check for distinguishing these different pipeline types. Though a decision tree can never answer all questions that arise, hopefully it will assist as a first step in preparing an inspection program and help to "point the finger" in the right direction.

Conclusion

Today, many pipelines previously considered unpiggable can be inspected from the inside. A toolbox approach must be used for a successful inspection ensuring that the most suitable non-destructive testing technique is available as well as addressing the issues of accessibility, negotiability and propulsion which differentiate the unpiggables from the piggable lines.

Tailor-made procedures are necessary to accommodate the special requirements of each line. The importance is that a variety of technical aspects covering drive, optimized inspection techniques, maneuverability inside the pipe and also procedural aspects, built largely on experience and skills sets of the personnel involved must be considered.

It can therefore be stated that a vast proportion of the pipelines globally which were deemed unpiggable can now be inspected from the inside with full coverage and with all the associated benefits. It may therefore be advisable to refer to these lines as "challenging" in future and leave the term unpiggable to the proportion of lines which cannot be inspected from the inside at all and must be accessed from the outside. ***P&GJ***

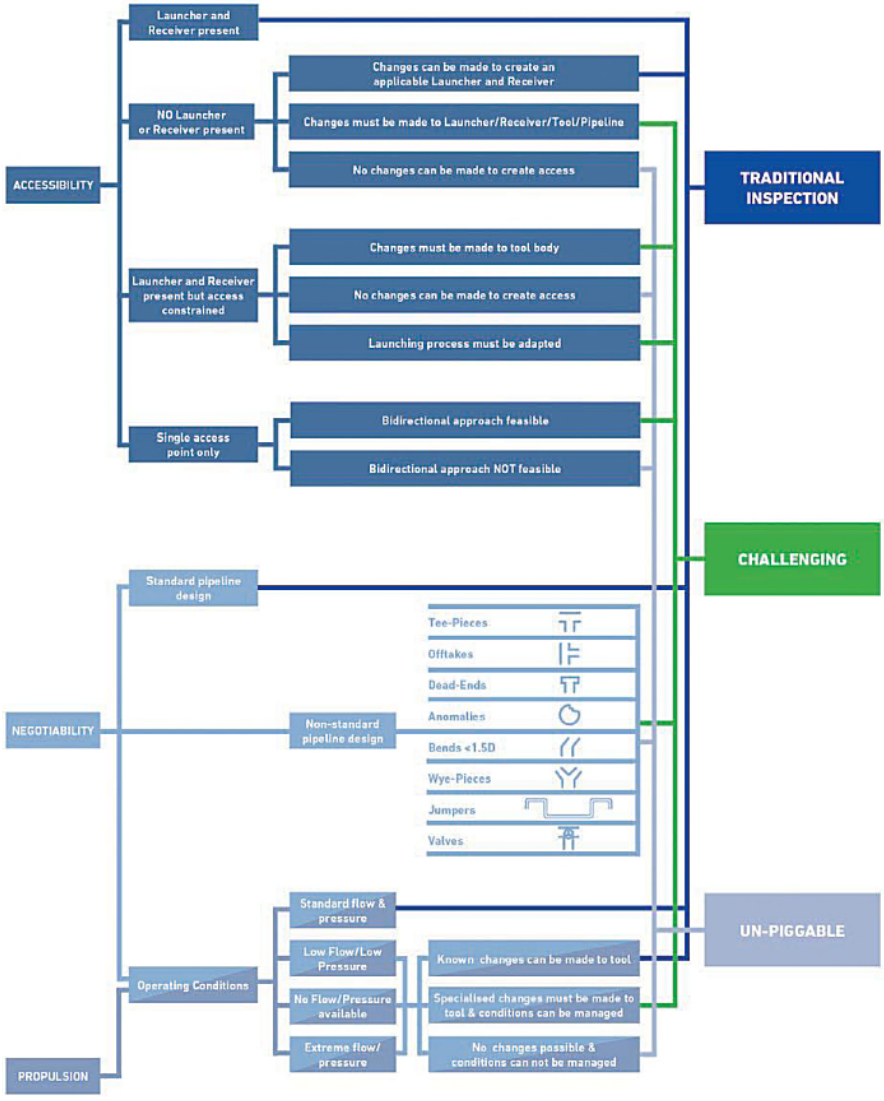

Figure 6: Flow chart for initial identification for a challenging inspection scenario.

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ILI Offers a Technology that Will Continue to Advance

By **Nicholas Newman,** Contributing Editor

There are about 3.5 million kilometers of oil and gas pipelines worldwide needing regular cleaning, inspection and maintenance, according to the U.S. Energy Information Agency (EIA).

A pipeline's insides are increasingly subject to inspection by smart pigging devices (known as inline inspection tools, intelligent or smart pigs) to detect corrosion, wax deposits, cracks and more. Smart or intelligent pigs are tools that run in the pipeline with integral sensors that detect, record and store details about the condition of the pipe for central analysis to guide maintenance and repair activities. Inline inspection (ILI) tools house a variety of technologies that have specific "missions" in detecting defects resulting from pipeline threats.

Today, North America accounts for around 48.5% of the global market, followed by Europe (19.4%) and Middle East & Africa (8.8%). World leaders in IL technology and services include companies such as T.D. Williamson, ROSEN Group, GE Oil & Gas (PII Pipeline Solutions), NDT Global and Enduro, among others.

Why Are Intelligent Pigs Used?

ILI tools inserted into the pipeline at special pig launch-and-receive facilities (commonly called traps) and typically move with the flow of oil or gas at speeds of between 0.5 and 3 meters per second (m/s).

ILI tools offer time savings, environmental and safety benefits. According to Mike Kirkwood, Market Development director – Transmission, at T.D. Williamson, "Using inline inspection tools provides the operator with the added advantage of not shutting down the pipeline to detect potential integrity threats. Alternative methods such as a hydrotest (where the pipeline is filled with water and subjected to a pressure higher than its operating pressure) can be costly and time-consuming.

LI tools are packed with sensors and electronics for measurement and data collection for monitoring the pipe's condition. The sensors, electronics and power source (batteries) are protected from the extreme pressures and high temperatures

of a pipe's interior in what are basically pressure vessels. Data are recorded through the use of solid-state memory and then, once extracted from the pipeline, downloaded and analysed using expert data analysts.

ILI tools vary in terms of function. One important parameter is diameter. As the diameter of the pipe reduces, the amount of space available to accommodate inspection technologies also reduces, hence, the length increases. So, for small-diameter pipelines, the tools are long – about 2 to 4 meters, large-diameter tools can be short, say, 1 meter.

Likewise, the technology employed varies according to the required function. For example, levels are often detected using magnetic flux leakage (MFL) tools, whereas cracks require an ultrasonic technology (UT) or a derivative called electromagnetic acoustic transducers (EMAT). Simpler ILI tools can also be used to detect changes in internal geometry such as ovalities, dents and expanded pipe. A more recent trend is to combine technologies, enabling the detection and assessment of combined or interacting defects, such as dents and corrosion, cracks in wrinkles, etc.

As pipelines enter more challenging environment such as deepwater offshore and higher temperatures, and transport different and more aggressive products, new inspection technologies are being brought to the market. For example, Norwegian pipeline and subsea inspection business Halfwave AS offers pigs using acoustic resonance technology which has the ability to look at very thick-walled pipe that is not common onshore.

The frequency of inspections also varies. Recently built pipelines in the U.S. require inspections every five to seven years, depending on whether it is a gas or a liquid line. Others, such as the gas pipeline interconnectors that link the U.K. pipeline network with its neighbors in Belgium, Holland, Ireland and Norway, are inspected on average every two years, reports British energy regulator OFGEM. Regulations also play their part in setting the periods for re-inspection: rule-based set intervals following a given time period (e.g., five and seven years) vs. goal-based where the period is set on the basis of risk.

Drivers Behind More Inspection

Tightening regulations are a major factor in continued demand for ILI services. According to Kirkwood, "The world market for ILI services is about $1 billion a year and growing by around 6% a year, due to more stringent regulatory and changing supply/demand needs." Economic recovery and increased consumption of petroleum products for vehicles and natural gas for electricity will also increase demand for ILI services as pipelines are maintained as major energy arteries.

Problems

ILI tools are not infallible and still experience limitations of detection when defects are small enough. In addition, if cleaning

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pigs are not used to clean the pipe before the smart pig is sent in, those "misses" can multiply with possible expensive consequences. Therefore, cleaning generally goes hand-in-hand with smart pigging programs.

There is also the consideration of cost. The United Kingdom Trenchless Society reports that the cost of carrying out an intelligent pig survey is expensive – about $607 per meter. While this may represent good value for maintaining the integrity of long-distance pipelines such as the Rockies Express 2,723-km natural gas pipeline, it is unlikely to be economically feasible for water mains.

During an ILI run, the tool is unable to directly communicate with the outside world due to several factors, including the distance the pipeline is underground or underwater and the materials that the pipe is made of. Plus the tool is at about 3 m/s. It is therefore necessary that the tool uses internal means to record its own movement during the trip.

This can be achieved by use of odometers and gyroscopes that measure tilt and XYZ location backed with geographical position. The tool records this positional data so that the distance, including that along the way, can be interpreted later to determine the exact path taken.

Another problem facing pipeline owners, and at the same time constraining the market, is that, according to Kirkwood, "Some 40% of transmission pipeline cannot be easily inspected by standard intelligent tools." Since tool passage may be impeded by reductions in diameter, valves, pressures, temperature, etc., lines can be incompatible with standard inspection devices.

However, many of the ILI providers are looking at novel ways to enter these challenging pipelines; they are also non-intrusive methods such as direct assessment, which will mean most all pipelines can be brought up to acceptable integrity levels.

Current and Future Developments

Improved miniaturization and increases in computing speed and battery life have significantly reduced the cost of advanced ILI runs. Increasing diversity of function is also a trend.

"We are seeing the development and usage of sensor devices carrying out a whole range of duties and missions," said Kirkwood. In this way, the next generation of tools will provide the best integrity picture in a single run.

Alongside this, we are seeing the ongoing development of tools to produce more accurate information on metal loss and crack detection, facilitating a significant improvement in inspection reports. Operators are customarily supplied with pipeline listings detailing every weld, fitting and feature, whether it be from corrosion or mill/manufacturing in origin.

As part of the service, the operators now receive software, which allows the pipeline's engineers to view, and in some cases, manipulate the data from which the report is produced. Operators view the tool-recorded signals and can generate their own listings, filtering the report along criteria such as the percentage of metal loss, clock position and sentencing, thus significantly enhancing the inspection report. The quality of the report is one of the most critical parts of the inspection project. It is, after all, the end-product for which the client is paying.

Kirkwood believes "inspection is a primary element in the proof of an effective integrity management program, but it's only a snapshot of the current status. In the future, additional data sources will be live, contributing to the current and future views of the pipeline's health." This will be the subject of future articles as technology becomes available to collect, manage and support decisions based on real-time data and predictive algorithms. ***P&GJ***

GPR, EM Technologies Offer Rewards in Environmental Assessments

By **Brian Jones, GSSI**

Geophysical surveys can be the bedrock – pardon the pun – of environmental projects, from locating abandoned underground storage tanks (USTs) and utilities, to complex mapping of geology in remedial investigations and finding landfill boundaries and other buried unknown problems.

In the past few decades, a variety of non-destructive testing methods have gained in popularity over expensive and time-consuming drilling and digging for environmental projects. Among these, the method of pairing ground penetrating radar (GPR) with electromagnetic (EM) induction instruments is one that shows great promise in significantly reducing survey time and costs.

Geophysical Toolbox

In the past, most environmental scientists and geologists relied on destructive technologies, including drilling and excavating test pits. Depending on the site and project budget, a survey may require drilling or digging one or two holes for a small site, or more than 30 holes for large sites.

On average, each borehole into the ground on an environmental site costs $5,000-10,000, so costs for drilling or soil sampling can be high. And not only are these methods slow and costly, they merely produce point measurements, rather than a continuous profile.

In response, companies have more recently come to rely on a variety of other non-destructive survey methods. Chief among these is ground penetrating radar (GPR), which sends a tiny pulse of energy into a material via an antenna. An integrated computer records the strength and time required for the return of any reflected signals.

Subsurface variations will create reflections that are picked up by the system and stored on digital media. These reflections are produced by a variety of materials, including geological structure differences and man-made objects such as pipes and foundations. GPR is considered the most accurate, highest resolution geophysical technology.

In general, GPR works best in dry sandy soils with little salt content, but dense clay-based soils are difficult to penetrate with GPR. In some situations, penetration depth may be limited to a few feet or less within clays, whereas targets residing in sandy soils could be detected at depths of 30 feet or more.

A GPR survey can be done at a cost of $1,000-2,000 per day, which means one can cover an entire site with GPR for less than the cost of a single borehole. In light of these clear cost advantages, GPR is now often the preferred method on environmental and construction sites. Instead of boring three or four holes, companies can bore one hole and use GPR to match the results and correlate data across the remainder of the site.

Another method of measuring subsurface conditions is the seismic refraction method, which requires a seismic energy source, trigger cable (or radio link), geophones, geophone cable and a seismograph. Seismic equipment is useful for finding larger features such as soil layers and bedrock depths, especially when deeper information is required.

It works well in clay soils, where GPR is not effective, but it is quite time consum-

GPR units surveying the location of buried tanks at a gas station and looking for other underground obstructions.

ing. To set up and collect the data and then analyze it, only two to four single transects may be collected in a day, which allows for vertical cross-sections into the ground at those locations. By comparison, with GPR one could collect data using 5-foot spacing in two directions and cover an acre per day in the same amount of time.

Along with seismic refraction, a different tool widely used for mapping the depth of soils and rock is electrical resistivity imaging (ERI), which involves placing stakes in the ground and measuring electrical resistance. This tool also works well in clay soil. However, similar to seismic equipment, it takes longer and costs more to get the required data coverage.

Technicians must set up a row of 24-48 sensors (metal stakes) along the ground, typically in a straight line. The line can be as long as needed, but information only flows along that one line. One can collect 80 or more profiles of similar length with GPR in the same time it takes to collect two to four profiles using this technique.

Magnetometers measure the strength and sometimes the direction of a magnetic field. By detecting irregularities in the earth's magnetic field, a magnetometer can show the location of old tanks and drums, but only those that are made of ferrous material. A magnetometer won't locate plastic or concrete utility pipes or fiberglass tanks.

Some types of magnetometers, also known as pipe and cable locators, feature a transmitting wand waved back and forth over the ground's surface, searching for a signal. This does a good job of finding ferrous objects but does not provided accurate depth information like GPR.

Also useful as a reconnaissance technique are electromagnetic induction (EM or EMI) devices, which are based on the measurement of the change in mutual impedance between a pair of coils on or above the earth's surface. Most EM instruments are comprised of two or more sets of coils. These coils are electrically connected and are separated by a fixed distance.

EM devices can simultaneously examine soil conditions and locate objects found beneath the surface of the earth spatially, but do not provide good depth information.

One of EM's limitations is that it cannot be used in close proximity (5-20 feet, depending on manufacturer) of aboveground obstructions such as buildings, cars and fences. This makes it less useful for smaller urban sites like gas stations, where there tend to be numerous aboveground obstructions.

GSSI's Profiler™ EMP-400 frequency domain, EM profiling system, can get within 5 feet of aboveground obstructions and be used to locate metallic targets and measure soil conductivity – even at tighter urban sites.

GPR Gains Popularity

Among all of these options, GPR equipment has become considerably more popular in the last 10 years for environmental projects. It is commonly used for locating old USTs, oil tanks and gas tanks, as well as 50-gallon waste drums filled with chemicals that were routinely dumped on sites in the '70s and '80s.

It is also an important tool for mapping utility and product lines, old landfill boundaries, debris pits, buried environmental targets or waste. Finally, GPR is used in remediation investigations to map soil layers and depth to top of water table or bedrock. Contaminants mainly pool either on top of the water table or bedrock, so environmental scientists need to map changes in these features to plan their borings.

The upsurge in GPR's popularity is largely driven by cost and safety – it is far cheaper and much safer – to do a quick geophysical survey than drill numerous holes in the ground at a significantly higher cost. Cost has come down relative to other technologies, and it is easier to use. Older GPR units required a trained geophysicist to operate – with today's equipment users can virtually push a button and start scanning.

On some sites, there is a definite cost advantage to combining use of EM with GPR. On smaller projects, such as locating tanks at gas stations, GPR and pipe, and cable locators can easily get the job done alone. But for larger multi-acre projects, for example, multiple areas at old factory sites or large governmental cleanup sites, there can be huge cost savings in using EM first and then focusing the GPR only on "hot spots" or anomalous areas located using the EM.

There are three main reasons EM is a good first tool on large sites: you can collect data much faster; the device does not have to be in contact with the ground (or as close to it) as does GPR; and the EM device's scanning swath is slightly wider.

Because the EM is carried, rather than pushed or dragged like a GPR device, users can walk faster and maneuver around obstacles more quickly. It is far easier to collect data with the carried EM on sites where there may be overgrown grass, tall weeds, or rocks. Also, an EM can very easily be adapted to be pulled behind an ATV with a trailer or sled setup – again making data collection faster.

Most EM systems also have either built-in or plug-in global positioning systems (GPS), so one does not have to waste time setting up a physical grid (measuring, spray paint, pin flags, and the like).

After using an EM device as the first, fast survey, the user quickly plots that data, which can be done in the field on a laptop in about 10 minutes, and looks for anomalies, targets, and potential soil issues. EM cannot provide exact information on the target's depth, shape and orientation, but the data is easy to view, process, and even immediately overlay on maps.

GPR surveying is narrowed to only those target areas found with the EM, and the GPR is used to provide information on depths, size and orientation of targets in either 2D or 3D imaging.

Dealing with constantly varying soil or aboveground conditions from site to site is another reason why it pays to have both types of equipment in the company "tool bag."

For example, EM works much better in clay soils than the GPR, and GPR works much better in sandy soils than the EM. Users often bring both tools to an unknown site.

Lastly, each tool may be better at locating a specific target type – GPR can find both metallic and non-metallic objects, whereas EM is mainly good at finding metallic objects.

In some instances, GPR has difficulties with corrugated metal drain pipes because of the design and the way the GPR energy is scattered, whereas EM works well finding such large metal targets.

The cost benefit of pairing the two tools is based on the simple fact that EM is five times faster than GPR on the front end, which lets users focus use of GPR only on identified hot spots.

Let's look at this calculation using a 5-acre site. GPR takes about a day to do one acre well, so it would take five days to complete the entire survey. EM can complete the site in one day. Starting with EM would, therefore, allow completion of an initial survey in one day, leaving the second day for use of GPR. This cuts the project from five days to two.

The resulting savings can range from 30-60%, depending upon the site. Since GPR/EM consulting fees are typically in the $200-400 per hour range, the three- day savings could be $5,000-10,000.

Overall, using these technologies and adding to business capabilities instantly differentiates one from competitors, expands service offerings in a wide range of applications – construction, environmental, geotechnical, engineering and forensics – and offers the potential to significantly increase revenue for only a small investment. ***P&GJ***

Combating Noise in Gas Pipeline Transmission

By **Chris Peterson, IMI Critical Engineering,** Birmingham, England

Pipelines have been established for many years as the simplest and most economical way to transport high quantities of natural gas over long distances, moving gas from new shale fields and other production sources to LNG stations, local utilities, industrial plants and natural gas–fired electric power plants.

Natural gas pipelines only consume an average of 2-3% of the gas's potential energy to overcome frictional losses along the route, making them more cost-effective than the use of road or rail transport.

Pressure differentials are used to "push" the gas through transmission pipeline. However, as pipelines get longer, it becomes necessary to increase the pressure used and to add compression stations. Typically sited every 50-100 miles, compressor stations keep the natural gas flowing by boosting the pressure of the gas to compensate for pressure losses along the pipeline. Gas compressors work by increasing pressure, reducing the gas volume and increasing the density of the fluid.

Pipeline networks have become increasingly complicated, encompassing more branches, necessitating the inclusion of distribution hubs and metering stations via which the gas from a high-pressure line can be routed to various lower pressure distribution lines.

For example, high-pressure main feed lines can run at 1,200 psig, with medium-pressure main lines at 600 psig and low-pressure main lines at 200 psig. Distribution and pressure reduction occurs across "city gates" which are pressure-reducing, custody transfer, and metering stations. These stations can often be located in urban environments. In Los Angeles, for example, gas is imported via pipeline, stored around the city at a number of underground gas storage facilities, and withdrawn based on local demand requirements.

What is Noise and How Is it Created in Pipelines?

The main methods typically used to grow pipeline capacity are increasing gas compression and increasing pipeline diameter. Since the 1940s, pipeline companies have used both measures to improve the capacity and hydraulic efficiency of the systems. However, it is usually more cost-effective to increase gas compression, as the more the gas can be compressed (with higher pressure), the smaller the pipeline diameter can be.

In order to increase gas compression, more and more powerful, and subsequently more expensive, compressor stations will be needed. However, the cost of these stations will be lower in the long run than the cost of larger pipe diameter for the entire length of the run.

The trade-off for this economic benefit is an increased potential for noise generation as the equipment needed to achieve the high gas pressure can be a significant noise source. Compressors are noisy, as can be the control valves which regulate gas flow through the pipeline at the source station, compressor stations, distribution hubs and metering stations.

The conversion of static pressure to kinetic energy at the *vena contracta* in the control valve creates high-velocity jets which can be subsonic, sonic or even supersonic. Turbulence and sonic shock waves create a noise spectrum with a characteristic peak frequency.

In cross-country pipelines with compressor stations, potential noise-producing control valve applications include recycle valves, vent to valves that provide emergency pressure protection and blowdown valves. In gas-storage facilities, a wide range of control valve applications include gas-receiving, compression for storage, withdrawal, dehydrating, odorizing, and pressure reduction to distribution pipelines.

Typically, control valves have a controlling diameter much smaller than that of the inlet/outlet piping. Consequently, expanders are added to transition the flow from the smaller valve to the larger pipe. The expansion of the gas through this valve outlet expander can be another source of noise. This source is exaggerated when the expansion is achieved with eccentric reducers, compared with the use of concentric expanders.

Why Is Noise Such a Problem?

Excessive noise generation can be damaging to people's hearing and disruptive to the environment. The Environmental Protection Agency (EPA) has produced numerous studies documenting the dangers of acute noise, including high blood pressure, coronary disease, migraine headaches, and low-birthweight babies. The World Health Organization (WHO) published a report in 1999 called *Guidelines for Community Noise*, to standardize risk assessment and management of noise dangers among participating countries.

Between 70dBA and 85dBA, the noise

source becomes quite pronounced. However, long-term exposure to noise at this level is unlikely to damage human hearing. At 85dBA and above, the noise source reaches a level where sustained exposure can begin to damage human hearing. For these reasons, guidelines from the Occupational and Safety Hazard Administration (OSHA) mandate an 85dBA limit for exposure of up to eight hours.

The higher the noise source rises up the dBA scale, the shorter the duration of exposure becomes before damage can occur. At 140dBA, not only is hearing affected, but the human body will actually begin to feel pain from the sound waves.

Noise generated from pipelines can be (and usually is) subjected to restrictions imposed by the OSHA, WHO and the EPA or their local equivalents. Violations of these restrictions can result in severe penalties – including fines and shutdowns - as well as lawsuits from affected residents, businesses and advocacy groups.

Low-frequency noise, usually caused by standing waves, can result in the mechanical vibration of piping and ultimately physical damage to the pipeline structure. In addition, large-scale vortex eddies and shedding from the valve are key causes of low-frequency vibration, as are large-diameter jets from the valve trim.

Similarly, pipes can vibrate radially because of high-frequency noise generated in the valve. This can cause fatigue issues at welded attachments such as drains and thermocouples, with the potential for unforeseen catastrophic failure. Potential for fatigue failure increases when the ratio of pipe diameter to wall thickness squared increases.

The ability to effectively manage noise and maximize transportation efficiency is affected by increasingly stringent environmental regulations which influence equipment choices and siting of compressor stations.

For example, the pipeline company may have to install electric-powered compression instead of gas-powered compression (even if gas would be more efficient), or relocate compression to a less than optimal area, or even install larger diameter pipeline in lieu of additional compression (which may require additional right-of-way permissions and will be much costlier than compression).

Noise regulation is often defined not by local near-field noise, but by further field noise that can affect local residents. Noise requirements at property lines are generally limited to 55 dBA, and at night the noise levels can drop even lower. This can equate to low noise levels at the valve, sometimes in the 70dBA @ 3 ft. level.

Traditional Methods of Noise Attenuation

There are two components of noise: frequency (Hz) and amplitude (dB).Typically, noise amplitude, or magnitude, increases with higher pressure drops, which are an unavoidable issue in gas transmission.

Traditional methods of combating pipeline noise include using thicker or heavier pipe walls, adding acoustic lagging or enclosing the noisy equipment inside a building. However, each of these has its disadvantages.

Heavier pipe walls and thicker insulation become economically unacceptable for larger pipes on very long runs, especially for higher grades of piping material.

Meanwhile, although noise typically propagates and attenuates with distance, it continues to travel through the pipe with little attenuation. Noise attenuates at a rate of 6dB for every doubling of distance from a point source and at 3dB every doubling of distance from a line source (pipe) in free-field environments. However, it attenuates at only 1dB for every 30m of pipe travelled. This means that enclosing the noise equipment in a building is only effective until the pipe exits the building. Consequently, most pipelines are buried, with noise noticeable in the station location only.

Regulating stations can have buildings installed around the stations which can then provide acoustic noise reduction. However, these buildings present a safety risk as, when there are gas leaks, the gas can collect in the building and create hazards of either asphyxiation or explosion.

Finally, in cases of gas storage or in some pipeline systems where source and demand locations can swap, the same gas can flow in the reverse direction through control valves – making it far more challenging to design the equipment to minimize noise.

Best Practice in Noise Reduction

The best way to deal with noise generation is to address it at its source. Pipe walls have far better attenuating properties against higher frequency noise sources. This means that if the frequency of the noise can be made higher by using smaller discharge jets in valve trim designs, maximum advantage can be taken of the pipes' inherent noise-insulating properties.

When mixing pre-treated gas with production gas coming from the field, it may be necessary to balance this with larger passages if dirty service (gas with entrained solids) is being transported.

Multi-stage letdown can also be employed to reduce trim discharge velocity and to lower the magnitude of the noise generated. The ISA control valve guidelines for velocity and kinetic energy limitations provide useful advice on minimizing trim discharge velocity. Characterized valve trims (EQ% or modified EQ%) should be used to address potential noise generation resulting from variable demands on the system, while concentric expanders should always be employed over eccentric.

For further information visit www.imi-critical.com ***P&GJ***

Retrofitting Customized Valves and Actuators for Pipeline Monitoring Stations

By **Ray Herrera,** Vice President, Business Development, Process Controls, **Valin Corporation,** San Jose, CA

Oil and gas engineers face a major problem in accurately and reliably measuring and monitoring the various fluids that are introduced into oil pipelines from well site pumping stations. A thorough understanding of both the oil separation process and the properties of valves and actuators is required to correctly specify a system that will sufficiently measure and monitor these various types of fluids. Also, the conditions downstream from each well are different, requiring valves and actuators to be highly customized to their specific role in the process.

Existing pipeline equipment is often outdated and lacks the ability to deliver the performance and reliability of modern measurement and monitoring technology. However, it is costly and time-consuming to replace an entire monitoring station on a pipeline. The solution is to retrofit customized valves and actuators onto existing monitoring stations, thus improving performance and reliability while minimizing cost and time investments.

The key to correctly specifying valve and actuator pairs for pipeline monitoring stations is to match the process conditions with the equipment that will ultimately provide the greatest control. These process conditions include pressure, temperature and the composition of media within the pipeline including the type of material and the percentage of distribution of that material.

Pipeline Process Conditions

Pipeline retrofit projects each have a very specific set of process conditions that process engineers have to carefully consider in order to create the most reliable and accurate measurement system. For example, common line sizes vary from 2 to 14 inches along a pipeline. Well site flow rates can reach 1,200-1,500 bpd when the well is first brought on and then settle down to a 200 bpd volume for the longer term.

This varying amount of liquid flowing into the pipeline can cause a wide variance in flow rate within the pipeline. As these flow rates change over time, valve settings often need to be adjusted to compensate. Also, many valve and actuator combinations that were installed over a decade ago do not meet new measurement standards for many pipeline operations.

Pipeline monitoring station pressure often fluctuates from 25-250 psi, and temperature variation can be significant, depending on location and climate, generally 40-160°F. The material in pipelines is generally all liquid, but gas or solids have the possibility of entering the system if there is a malfunction upstream. These are additional conditions that require further customization of valves and actuators being retrofitted to individual systems.

Standard Pipeline Monitoring Equipment

In all monitoring stations attached to pipelines, it is necessary to maintain constant back pressure to keep pressure in the system, prevent gas from entering the system and achieve accurate measurement. This is normally accomplished using a self-operated back pressure regulator valve with no feedback or control system available. This is a less expensive valve with no automation option necessary to make any error corrections.

While self-operated pressure regulators are able to make corrections based on flow and pressure fluctuation, their capabilities are very limited and can cause inconsistent back pressure. For example, if the regulator is set at 100 psi, the actual pressure can vary by plus or minus 10 psi. This is known as the "droop" of a self-regulating valve, an inherent feature of these inexpensive pieces of equipment.

Additionally, when the regulator is set at a specific pressure, it is also set at a matching flow rate. When this flow rate increases or decreases, the pressure naturally changes along with it. A pressure regulator will not be able to adequately respond to these changing conditions and may result in damage to the system or inaccurate measurements.

This self-operated pressure regulator is one example of a generic piece of equipment that could be significantly improved by retrofitting an upgraded valve and actuator that are specifically customized to match the process conditions of the system.

Also, while most isolation valves on pipeline monitoring stations are manual quarter turn due to industry price concerns, newer functionality available using supervisory control and data acquisition (SCADA) systems have convinced many to upgrade to automated valves. These upgrades are readily available, assuming that process conditions can be adequately handled by the new equipment.

Matching Retrofitted Valves and Actuators to Process Conditions

When retrofitting new valves and actuators onto an existing pipeline measuring and monitoring system, it is vital to consider the existing equipment and adjust the specifications accordingly. A failure to do so could result in more severe problems than the original system.

In the example of the self-regulated valve, a process engineer would take the unwanted pressure variance into consideration and determine that an automated control valve would be required to meet the needs of the system. There can be other automated valves in a system that affect pressure such as a distribution center with multiple well sites feeding into one pipeline. The default actuator in this situation would be a lower-cost pneumatic actuator if an air compressor were available.

An electric actuator is the alternate choice due to electricity available at all monitoring stations. In the case of a pneumatic actuator, a diaphragm-type actuator would be preferable if increased positioning accuracy is needed, but if no compressed air is avail-

able to power a diaphragm actuator, then a high-performance electric actuator would be used instead.

As stated earlier, the flow rate of each well feeding into a pipeline can range from 1,200-1,500 bpd before decreasing to just 200 bpd after several months. As more wells feed into the pipeline, the flow range can vary significantly over time. Valves and actuators on monitoring stations need to be adaptable to meet the demands of these changing process conditions. This change in flow could create an additional challenge in states that require measurement to be proved on a regular basis.

In this application, the measurement system OEM designed a system with regulators and manual isolation valves. Because of the wide variance in flow rate, the regulator could be led to operate in an unstable manner during low flow conditions or could create a choke flow condition during high flow. Choked flow is the point where the pressure drop across the valve orifice has reduced the actual pressure below the media's vapor pressure. Under this condition, fluid is flashed to gas and the downstream measurement is inaccurate, making the meter nearly impossible to prove.

To improve the accuracy and reliability of the measurement, the solution was to design a system that would allow for a wide variation in flow rates over time. A PLC-based solution was implemented that would sense flow rate via a Coriolis meter while utilizing a program that took into account the rapid changes between high and low flow rates. It was vital to choose a control valve that had suitable rangeability to manage the extremes in flow rates.

Rangeability in a control valve is the amount of capacity that the valve can physically handle. It is determined by dividing the highest possible flow rate by the lowest possible flow rate and expressed in a ratio, e.g. 10:1. While self-operated pressure regulators commonly have a rangeability of 10:1, more robust control valves can offer performance up to 300:1. This higher performance allows the control valve to be more adaptable to changing flow rates while still achieving accurate measurement.

In the example application above, the choice was to utilize a segmented ball valve design which has a nearly full flow characteristic in the open position, and a tapered slot on the low end of the valve stroke which will control and pass the appropriate flow rates. This valve has an equal percentage characteristic, meaning that equal changes in valve position produce equal percentage changes in flow capacity. This means there is finer resolution for control on the lower end of the valve stroke and high-capacity changes on the upper end of the stroke.

The actuator that was chosen was an electric actuator. This was preferable because the maintenance of a pneumatic system in the very cold environment at this particular site was becoming a burden to the operations and maintenance teams involved. The actuator has a high accuracy electronic modulating card with feedback, internal heater and battery backup so the valve would move to a desired position in the event of a power loss.

This integrated solution has allowed the oil company to keep its measurement-monitoring system operating while reporting flow rates within the state's required accuracy standards. This was completed while retaining the majority of the existing equipment with only a few retrofitted upgrades to the control system, and control valves properly suited for the process conditions of the application. ***P&GJ***

Author: Ray Herrera *is Vice President of Business Development for the Process Control Division at Valin Corporation. He has over 25 years of experience sizing, selecting, selling, and servicing process control equipment specializing in control valves and instrumentation. He holds a B.S. in industrial engineering and A.S.T in electrical engineering technology.*

ConstructionScorecard

North American Pipelines Under Construction

PIPELINES UNDER CONSTRUCTION:

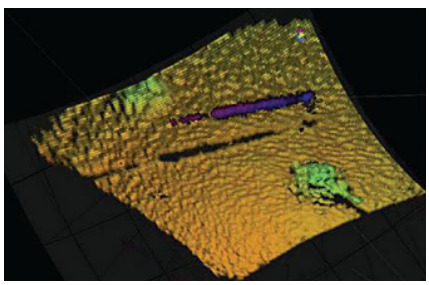
CONTRACTOR/ OWNER	PROJECT NAME/ LOCATION	MILES	COMPLETION DATE
U.S. - GAS			
Alaska LNG Project	Alaska LNG Project/Prudhoe Bay	800	2024
Arizona Pipeline LLC/Paiute Pipeline Co.	2015 Elko Area Expansion Project/ Elko, NV	35	2016
Bechtel/Cheniere Energy Inc.	Corpus Christi Liquefaction Project	22	2018
Blueknight Energy Partners LP	Leon, Walker and Houston counties, TX	160	2016
Burk Royalty Co. Ltd./Midcoast Energy	Ghost Chili Lateral/Houston County, TX	NA	2016
Columbia Pipeline Group	Smithfield III Expansion Project/PA - VA	NA	2015
DCP Midstream	Carlsbad, NM - Andrews, TX	164	2016
Energy Transfer Partners LP	Panola Pipeline/Carthage - Mont Belvieu, TX	181	2016
EQT Midstream	Ohio Valley Connector Project/OH - WV	49.5	2015
EQT Midstream Partners LP/ Range Resources – Appalachia LLC	PA	32	2016
Femaca/CFE	El Encino – La Laguna Pipeline/Waha, TX - Mexico	263	2017
Fluor Corp./NEXUS Gas Transmission	NEXUS Project/OH - MI	250	2017
Larrett Energy/NRG Energy	CO2 Project/Corpus Christi, TX	80	2016
Major Pipeline LLC/GreenHunter Pipeline LLC	Ohio River	34	2016
Meritage Midstream II/ Thunder Creek NGL Pipeline	Thunder Creek NGL Pipeline Extension/ Cheyenne, WY	140	2016
MG Dyess/East Tennessee Natural Gas LLC	Virginia Southside Expansion Project/ Kingsport, TN	100	2015
Michels/Gas Transmission Northwest LLC	Carty Lateral/OR	25	2016
Paso Norte Pipeline Group	NM - Chihuahua, Mexico	340	2017
Precision Pipeline/M3	Stonewall Gas Gathering Pipeline Project/Doddridge County - Braxton County, WV	67	2016
Precision Pipeline/WE Energies	West Central Lateral Project/Eau Claire County, WI - Tomah, WI	89	2015
Price Gregory/ Columbia Pipeline Group	East Side Expansion Project/Chester County, PA; Gloucester County, NJ	19	2015
Pumpco Inc./Energy Transfer	Pecos, TX - Presidio, TX; El Paso, TX - Pecos, TX	342	2017
Pumpco Inc.; Strike Construction/Lone Star NGL LLC	Lone Star NGL Pipeline/Bosque County - Mont Belvieu, TX	533	2018
Regency Energy Partners LP; American Energy	Utica Ohio River Project/Jefferson County, OH	52	2015
Spectra Energy	Algonquin Incremental Market Project/ NY; CT; RI; MA	40	2016
Strike LLC; Pumpco Inc./ Energy Transfer	Volunteer Pipeline/Brazos County, TX	70	2016
Tall Oak Midstream LLC	Payne, Creek, Logan, Lincoln, Noble and Pawnee counties, OK	250	2015
WHC Inc./EnLink Midstream	OH	45	2015
U.S. - OIL			
Boots Smith/Hess North Dakota Pipe Lines	Koene - Tioga, ND	26	2016
Boots Smith/Kinder Morgan	Sweeney, TX	24	2016
DC Welding & Construction/ Genesis Energy LP	Casper Express Crude Pipeline/Casper, WY - Douglas, WY	70	2015
Grand Mesa Pipeline LLC/ Rimrock Midstream	Grand Mesa Pipeline/Weld County, CO - Cushing, OK	550	2016
JP Energy Partners LP	Silver Dollar Pipeline Extension/Reagan County, TX	55	2015
Knight Warrior LLC	Madison County, TX - Houston, TX	160	2016
Medallion Pipeline Co. LLC	Santa Rita Lateral/Reagan County, TX	55	2016
Navigator Energy Services	Big Spring Gateway System/Martin, Glasscock, Howard and Midland counties, TX	450	2016
Paradigm Midstream	Sacagawea Pipeline Project/McKenzie County - Stanley, ND	76	2016
Pilgrim Pipeline LLC	Port of Albany, NY - Linden, NJ	166	2015
Plains All American Pipeline LP	Caddo Pipeline/Longview, TX - Shreveport, LA	80	2016
Plains All American Pipeline LP	Three Rivers, TX - Corpus Christi, TX	125	2017
Progressive Pipeline/Phillips 66; Energy Transfer Partners LP; Sunoco Logistics Partners LP	Bayou Bridge Pipeline/Nederland, TX - Lake Charles, LA	60	2016
Pumpco Inc.; Strike LLC/ Sunoco Logistics	Permian Express Phase II/Colorado City, TX - Wortham, TX	308	2017
Rimrock Midstream LLC	Rimrock Platte River Gathering System/ Weld County, CO	150	2016
SemGroup Corp.	Maurepas Pipelines/U.S. Gulf Coast	104	2016
Tall Oak Midstream LLC	Cushing, OK	20	2015
Two Rivers Pipeline/Frontier Energy Services	Alpha Crude Connection/Lea County NM - Winkler County, TX	400	2017
U.S. Pipeline/Suncor Energy	Rocky Mountain Pipeline/Cheyenne, WY - Fort Lupton, CO	70	2016
U.S. - OTHER			
Indianhead Pipeline Services LLC/U.S. Pipeline Inc.	Christian, Fayette, Macon, Marion and Shelby counties, IL	75	2016
InfraSource LLC/NIPSCO	Newton County, IN	400	2017
Lunda Construction Co./U.S. Pipeline Inc.	Christian, Fayette, Macon, Marion, Shelby, DeWitt, Livingston, Macon and McLean counties, IL	168	2016
MDS Boring and Drilling Inc./ Strike	Houston, Grimes, Madison and Walker counties, TX	50	2016
Michels Corp./Vermont Gas	Addison Pipeline Project/Cornwall, VT	44	2015
Price Gregory International Inc./TransCanada Keystone Pipeline LP	Chambers, Harris and Liberty counties, TX	48	2015
Sheehan Pipe Line Construction Co./Truckline Gas Co. LLC	DeSoto County, MS; Crockett County, TN; Ballard, KY; Franklin, IL	280	2016
T.G. Mercer Consulting Services Inc./Grand Mesa	Kit Carson County, CO	151	2016
Welded Construction LP/Williams Gas Pipeline	Brunswick, Charlotte, Halifax, Mecklenburg and Pittsylvania counties, VA	92	2015
U.S. - OFFSHORE			
Subsea 7 S.A./ Royal Dutch Shell	Gulf of Mexico	27	2016
The Bayou Companies LLC	Gulf of Mexico	46	2016

CONTRACTOR/ OWNER	PROJECT NAME/ LOCATION	MILES	COMPLETION DATE
U.S. - PRODUCTS			
Williams Transco	Texas Belle Pipeline/Mont Belvieu, TX	28	2015
Wood Group Mustang/Dow Pipeline Co.	Freeport, TX - Mt. Belvieu, TX	140	2016
CANADA - GAS			
Enbridge Gas Distribution	GTA Project/Toronto	NA	2016
Enhance Energy Inc.	Alberta	149	2016
Pembina Pipeline Corp.	Simonette Pipeline Expansion/Simonette, AB - Fox Creek, AB	37	2016
CANADA - OIL			
Access Pipeline Inc.	Northeast Expansion/Conklin, AB - Redwater, AB	185	2015
CH2M HILL/TransCanada Corp.	Saint John Extension/New Brunswick	248	2016
Enbridge Athabasca	Athabasca Pipeline Twinning Project/ Winifred Lake - Hardisty, AB	214	2016
Enbridge Inc.	Line 9B Reversal Project/Westover - Montreal	397	2016
Enbridge Inc.	Woodland Pipeline Extension Project/ Cheecham - Edmonton	228	2015
Inter Pipeline Ltd.	Mid-Saskatchewan Pipeline System/ Saskatchewan	56	2015
TransCanada Corp./Fort Hills Energy LP	Northern Courier Pipeline/Fort Hills - Fort McMurray	56	2017
TransCanada Corp./Phoenix Energy Holdings	Grand Rapids Pipeline/Fort McMurray - Edmonton	310	2017
CARIBBEAN/SOUTH & CENTRAL AMERICA - GAS			
CFPS Engenharia e Projetos S.A./Parnaíba Gás Natural	Maranhão, Brazil	25	2016
Odebrecht/ProInversion	Southern Peruvian Pipeline/Malvinas - Chiquintirca	620	2018
Tipiel S.A/Consorcio Constructor Ductos del Sur	Camisea field - Southern Peru	1056	2018
MEXICO - GAS			
Capstone Turbine Corp.	Los Ramones Pipeline/Northeastern Mexico	531	2018
Carso Energy; Energy Transfer Partners; MasTec Inc.	Waha-Presidio Pipeline/Chihuahua	143	2016
ICA Fluor/TAG Pipelines Sur S. de R.L. de C.V.	Ramones II Sur Gas Pipeline/San Luis Potosí, Querétaro - Guanajuato	181	2016
Infraestructura Energética Nova SAB de C.V./Comisión Federal de Electricidad	Ojinaga - El Encino, Chihuahua	127	2017
Pemex; Guatemala	Salina Cruz - Escuintla, Guatemala	373	2016
MEXICO - OFFSHORE			
Saipem/Pemex	Gulf of Mexico	121	2017
Saipem/Transportadora de Gas Natural Norte-Noroeste	El Encino, Chihuahua - Topolobampo, Sinaloa	341	2016

TECHNOTES
Product Development

UTEC Completes Challenging Project in Cook Inlet

UTEC Survey was recently hired to provide a positioning solution for the installation of a monopod liquid natural gas platform and 30-km, 10-inch LNG pipeline for a major operation located in Alaska's Cook Inlet. Twenty-four field personnel were mobilized and engaged with Coda Octopus Products for use of their Echoscope technology to provide positioning and survey services for five vessels.



Data set showing pie being laid down

The cutting-edge project was the first monopod installation in the Cook Inlet in 25 years and marked the first time that four Echoscope systems operated simultaneously. The intended use of the Echoscope sonars was a final verification of the deployment position, but due to poor visibility caused by tidal changes, 6-7 knot currents and heavy silt, UTEC chose to use multiple Echoscopes in combination with measurements for completion of the installation.

The Echoscope provides a real-time 3D-detailed, geo-referenced image of moving and static subsea hardware and features – even in low-to-zero visibility conditions. Three Echoscopes were installed on the pipelay barge (one on the bow, one on the aft and one on the end of the stinger). This combination allowed monitoring of touchdown and pipe position in the stinger as well as identification of potential hazards on the route.

Utilizing four Echoscopes simultaneously allowed the monopod to be seen as it was lowered to accurately position it onto a kingpile. The innovative approach enabled UTEC and its client to view operations in real time, rotate the viewing perspective and make measurements. Combining the measurements and on-screen images resulted in increased efficiency.

View of the Echoscope.

Commenting on the completion of the project, UTEC Vice President of Sales and Commercial Doug Catenaci said, "Given the environmental challenges of this project, we couldn't be more pleased with the results."

Blair Cunningham, Coda Octopus President of Technology, said, "This was an exciting project. Working with UTEC to deploy four Echoscopes for concurrent operations in this harsh and complex environment not only allowed real-time visualization and measurement in low-visibility conditions, but also enabled the task to be done safely and within record time." ***P&GJ***

BUSINESS

Association News, Personnel Changes, Mergers & Aquisitions

Association News

Dr. Ganesan (Subbu) Subbaraman joined the **Gas Technology Institute (GTI)** as the first member of the newly launched Fellowship Program.

DePriest

The executive assembly of **Pipeline Research Council International, (PRCI)**, elected Phillip H. DePriest, manager of Integrity, Damage Prevention and Risk Management at Marathon Pipe Line LLC, as chair for a two-year term ending in September 2017. He replaces Christophe Renier, Industrial Assets Programs vice president at France-based Engie, who will continue serving on the executive assembly and executive board as past chair. Jeff Whitworth, manager, Reliability & Integrity-Americas at Shell Pipeline Co., was elected vice chair.

Personnel Changes

Steph

Henkels & McCoy, Inc. named **Jason Steph** as vice president, Pipeline Division, managing the Pipeline Services & Industrial/ Facilities groups. Based in Houston, Steph will manage pipeline construction backlog and oversee the expansion of the pipeline division's facility capabilities.

Hill

The company also announced the promotion of **Richard Hill** to vice president, Major Pipelines. He will be based in Norman, OK.

Wood Group Mustang appointed **Elaine Lisenbe** as CFO and **Valencia Amenson** as vice president, Human Resources. Both will join Wood Group Mustang's executive leadership team.

Select Energy Services, LLC appointed **Gary Gillette** senior vice president and CFO. He will be based at Select's Gainesville, TX operational headquarters. **Eric Mattson** will continue as executive vice president and CFO for parent company, SES Holdings, LLC at Houston corporate headquarters.

Sempra Energy announced **Jessie J. Knight, Jr.**, executive vice president of external affairs for Sempra Energy and chairman of Southern California Gas Co. (SoCalGas) and San Diego Gas & Electric (SDG&E), retired Nov. 1. **Steven D. Davis**, president and COO of SDG&E, will succeed Knight as executive vice president of external affairs and corporate strategy for Sempra.

Atmos Energy Corp. announced promotions to its senior management team. **Michael E. Haefnerm**, executive vice president, will become president and COO. **Marvin L. Sweetin**, senior vice president of Utility Operations, was promoted to the newly created position of senior vice president of Safety and Utility Services.

Sean Gourley was elected as an independent director of Anadarko Petroleum Corp. **Amanda M. McMillian** was promoted to senior vice president, general counsel, corporate secretary and chief compliance officer. Anadarko's **Robert K. (Bobby) Reeves** will assume the new title of executive vice president, law and chief administrative officer, and will remain a member of the executive committee.

Southcross Energy Partners, L.P. appointed **Kelly J. Jameson** senior vice president, general counsel and **Mark A. Pyburn** as vice president, Gas Marketing of Southcross Energy Partners GP, LLC.

Harte Research Institute Chairman **Dr. Richard McLaughlin**, was appointed by the National Academy of Sciences to serve on its newly created committee on Environmental Sciences and Assessment for Ocean Energy Management. The committee will provide independent oversight and assistance in the management of the U.S. offshore energy resources.

Smith Flow Control promoted **Sander van den Bos** to international business development manager.

James "Bruno" Del Buono was named a key account manager by Greene's Energy Group.

WHC Energy Services, LLC Board of Directors announced new job roles for two officers. **Fred Roberts**, previously CFO, was named executive vice president and CFO and **Rick Mills**, previously vice president of Project Services and Controls, was named senior vice president.

Emerson named Scott Anderson as president to manage its Control Techniques business unit from company headquarters in the United Kingdom.

Company News, Mergers & Acquisitions

The judges' votes are in. **B&T Drainage Inc.** from Marshall, IL won the Ultimate Crew contest, sponsored by **Vermeer**. B&T Drainage bested three other crews during the Ultimate Crew Underground Showdown, a live drilling competition held at the International Construction and Utility Equipment Exposition (ICUEE) 2015 in Louisville, KY.

LQT Industries, LLC won two projects to upgrade and refurbish single-lift accommodations that house a total of 320 personnel on a drillship and a semisubmersible located in the Gulf of Mexico. The projects are scheduled to be completed by the end of the year.

H&E Equipment Services Inc. has a new branch located at 2066 South 10th St. in San Jose, CA, 95112. The company has also relocated its operation in San Antonio, TX to a new facility at 5327 Tex-Con Drive, 78220.

Bandit Industries added three new dealers to its North American network: **Southland Machinery**, serving central and northern Alabama; **FMI Equipment**, serving eastern Washington, northern Idaho and western Montana; and **Yancey Bros. Co.**, serving Georgia.

DNV GL is building a conference center and large-scale fire and explosion demonstration area at its major hazard testing and research center in Cumbria, U.K. The new training facility is due to be completed in December.

Michael Grimm, vice president of Machine Sales at HOLT CAT and Arron W. Smith, president of Precision Demolition, LLC

Leaders from **HOLT CAT®**, **Caterpillar®** and **Precision Demolition** gathered recently at Precision Demolition's headquarters in Lewisville, TX to celebrate deployment of VisionLink™, a fleet management solution. This telematics technology enables customized health and utilization reports, provides additional onboard safety features, and can map fleet movements and overall machine capabilities.

Trelleborg's pipe seals operation appointed Product Group Manager **Dave McArthur** to provide its North American customers with a dedicated contact for the pipeline rehabilitation market. He will be responsible for day-to-day management of its pipe rehabilitation solutions in North America including the introduction of new products.

ARB Midstream, LLC, a Denver, CO-based midstream company, acquired **Sunwest Canada Limited**, a crude oil marketing and trading company headquartered in Calgary. Sunwest will operate under the name of **ARB Midstream Logistics Canada, ULC**. ***P&GJ***

Thermo Fisher Scientific

Thermo Fisher Scientific has launched the Thermo Scientific AutoLACT (lease automatic custody transfer) flow computer control system which is designed to facilitate the transfer of liquid hydrocarbon from storage tanks or trucks to refineries or centralized processing facilities while accurately recording data for each transaction. The system offers several features, including: touchscreen capabilities that allow transporters to comply with API 6.1 (Metering Assemblies Lease Automatic Custody Transfer – LACT System); technology to meet API 21.1 custody transfer requirements; an optional printer for immediate receipt printing needs; and additional security measures, including the ability to validate the identity of the driver and a grounding check to facilitate adherence to proper safety protocols. www.thermoscientific.com/autolact

Hoover Container Solutions

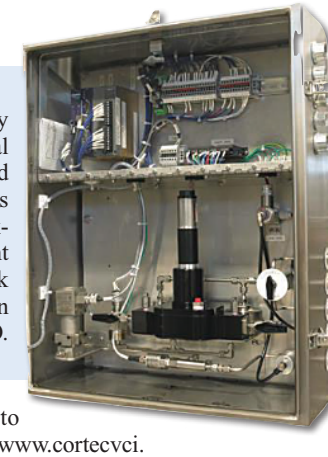
The Liquitrac Tracer is a battery-powered GPS unit that can be easily attached to any of Hoover's comprehensive product line offerings to track asset location – domestic or internationally, even in the most hazardous environments. The ATEX-certified unit is equipped to support calling-based movement, meaning immediate notification of movement of a GPS or GPS-equipped unit. The unit features prolonged battery life to ensure customers receive reliable coordinates to stay connected to their entire fleet 24/7. www.hooversolutions.com.

Doosan

Two new Doosan crawler excavators are added to the Tier 4 compliant lineup, featuring improved performance, operator-focused comfort, fuel economy and jobsite durability. The 14-metric-ton DX140LC-5 and DX140LCR-5 Tier 4-compliant machines replace the interim Tier 4 "dash-3" models. The DX140LCR-5 model offers a shorter tail swing, allowing operators greater flexibility where space is a premium without sacrificing performance. Both comply with Tier 4 emission standards with modified diesel engines and aftertreatment technologies. A new selectable feature, Smart Power Control (SPC), is available on both models and consists of two systems — Variable Speed Control and Pump Torque Control — that work together to improve machine efficiency while maintaining productivity and reducing fuel consumption.www.doosanequipment.com.

GPL Odorizers

GPL Odorizers manufactures environmentally friendly odorant injection systems for low- and high-pressure natural gas pipelines. The odorizers are ventless, self-contained and do not discharge gas into the atmosphere. That improves safety, saves pipeline gas, reduces odor, which lowers leak-call complaints. GPL Odorizers LLC acquired the odorant injection product line of Sentry Equipment Corp. (Zeck Systems) earlier in 2015. With the acquisition, distribution was assigned to Linc Energy Systems in Wheat Ridge, CO. www.lincenergysystems.com.



Technical Toolboxes

The PETROLEUM skyBox is a suite of PowerTools from Technical Toolboxes allowing the user to model a simple pipeline or a complex network of pipelines and simulate the dynamic multiphase flow. The tools are designed to help: reduce internal corrosion; determine locations and types of internal corrosion; episodic upsets; wet gas and petroleum liquid lines; reduce erosion corrosion; determine locations of deposits; determine slugging and other flow regimes; and determine locations of plugging. These flow models allow operators to simulate from wellhead to process facility, startups to shutdowns and from steady state to transient flow. http:petroleumskybox.com.

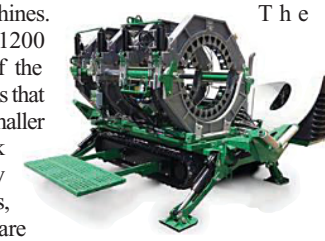
Cortec® Corporation

Cortec® Corporation introduces a new product in corrosion protection to reach these

hidden areas – EcoFog® VpCI®-309 Nano. This patent-pending product is a Vapor phase Corrosion Inhibiting (VpCI®) powder designed to protect ferrous metals in hard-to-reach recessed areas, interior cavities, and voids. It is easy to apply with little or no surface preparation needed and provides superior protection to ferrous metals including carbon steel, stainless steel, and aluminum. This product does not contain silicates, phosphates, nitrites, or heavy metals and provides up to 24 months of continuous protection. It is available in 5-pound, 50- pound and 100-pound lined drums. This product should be stored in a sealed container in a dry warehouse avoiding direct exposure to sunlight, with temperature not exceeding 150°F. Shelf life is up to 24 months. www.cortecvci.com.

McElroy

The release of the TracStar® 1200 brings the largest pipe fusion capability to date in McElroy's popular line of self-propelled, track-mounted fusion machines. The TracStar 1200 has many of the same benefits that make its smaller models work so efficiently on jobsites, but there are some major upgrades. It features an advanced emission control engine that burns ultra-low-sulfur diesel to meet the EPA's latest Tier 4 standards. The cowling has been redesigned so technicians have better and quicker access to the engine for maintenance. The TracStar 1200 butt fuses pipe from 16-inch OD to 48-inch OD (450mm to 1,200mm) and can traverse most any terrain - mud, loose soil, snow and grades up to 30%. It is self-contained with an on-board generator for powering the hydraulic pivoting heater and facer. www.mcelroy.com/fusion.



LaValley Industries

LaValley Industries' new TONGHAND® exit-side wrench attachment provides horizontal directional drillers with a way to torque up and break pipe joints, reamers, and subs. The TONGHAND hydraulic attachment's patented rotation arms, gullwing design and integral TongVise™ are controlled by a single operator inside any 30-ton excavator. The TONGHAND works with pipe tool joints ranging in size from 6.5-10 inches. The rotation arms allow the operator to thread and unthread drill pipe connections. The 120,000 ft.-lb. torque capability on its patented vise, and the precision pipe control design, allow workers to remain safely away from drilling components while breaking joints, loading and unloading drill string components, and positioning drill rod throughout the job site. www.lavalleyindustries.com ***P&GJ***

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MEETINGS

Upcoming events 2015-2016

Nov. 16-18, 2015 Natural Gas STAR Annual Implementation Workshop, Sheraton Pittsburgh Hotel at Station Square, Pittsburgh, PA. www.epa.gov/gasstar/workshops/index.html.

Nov. 18, Pigging Products & Services Association Operational Pipeline Pigging Seminar, Ardoe House Hotel and Spa, Aberdeen, UK. Phone: +44 (0) 1224 860 642; Web: www.ppsa-online.com/seminar.php.

Nov. 17-20, Subsea System Design & Project Execution Course, Royal Sonesta Hotel, Houston, TX. Phone: (713) 449-3222; Fax: (713) 521-9255.

Nov. 18-20, Latin American and Caribbean Petroleum Engineering Conference, Quito, Ecuador. www.spe.org/events/lacpec/2015/en/.

Nov. 25-26, European Gas Technology Conference 2015, Park Royal Palace Hotel, Vienna, Austria. Web: www.egatec2015.com.

Nov. 30-Dec. 4, Pipeline Integrity Courses, Westin Calgary Hotel, Calgary, Alberta, Canada. Phone: (713) 449-3222; Fax: (713) 521-9255.

Dec. 6-9, International Petroleum Technology Conference, Qatar National Convention Center, Doha, Qatar. Web: www.iptcnet.org/2015/doha/index.php..

2016

Feb. 3-4, 2016 Underground Construction Technology (UCT) International Conference & Exhibition, Georgia World Conference Center, Downtown Atlanta, GA. Phone: (281) 558-6930; Fax: (281) 558-7029; Email: kfrancis@uctonline.com.

Feb. 8-11, 28th International Pipeline Pigging & Integrity Management Conference plus Training Courses and Exhibition, Marriott Westchase Hotel, Houston, TX, Phone: (713) 529-5929; Fax: (713) 521-925; Email: bjlowe@clarion.org.

Feb. 9-11, 6th Annual Topsides, Platforms & Hulls Conference and Exhibition, Moody Gardens Hotel & Convention Center, Galveston, TX. Web: www.topsidesevent.com.

Feb. 15-20, 2016 Distribution Contractors Association 55th Annual Convention, Naples Grande Beach Resort, Naples, FL. Phone: (972) 680-0261; Fax: (972) 680-0461; Web: www.dca-online.org.

Feb. 23-27, 68th Pipe Line Contractors Association Annual Convention, Hyatt Regency Scottsdale at Gainey Ranch, Scottsdale, AZ. Phone: (214) 969-2700; Web:www.plca.org.

Mar. 14-15, LNG Congress, Royal Garden Hotel, London, England. Phone: +44 (0)20 3769 3392; Fax: +44 (0) 20 7222 688; Web: www.bgs-group.eu.

Mar. 22, Pipeline Opportunities Conference, JW Marriott (Galleria Area), Houston, TX. Phone: (281) 558-6930; Fax: (281) 558-7029; Email: kfrancis@uctonline.com.

Mar.30-31, 2016 Ark-La-Tex Oilfield Expo, Shreveport Convention Center, Shreveport, LA. Web: www.2016ArkLaTexOilfieldExpo.com.

Apr. 5-7, MCE Deepwater Development 2016, Palais Beaumont, Pau, France. Phone: (832) 242-7048; Web: www.MCEDD.com.

Apr.13-16, National Association of Pipe Coating Applicators (NAPCA) Annual Convention, Marriott Harbor Beach Resort & Spa, Fort Lauderdale, FL. Phone: (713) 655-5761; Fax: (713) 655-0020; Email: merritt.chastain@ogletreedeakins.com.

Apr. 19-22, 2016 AGA Operations Conference, Arizona Biltmore, Phoenix, AZ. Phone: (202) 824-7000; Web:www.aga.org.

Apr. 26-28, ENTELEC 88th Annual - Spring Conference & Expo, George R. Brown Convention Center, Houston TX. Web: www.entelec.org.

May 2-5, 2016 OTC (Offshore Technology Conference), NRG Park, Houston, TX. Phone: (972) 952-9494; Fax: (972) 952-9435; Web: octnet.org. ***P&GJ***

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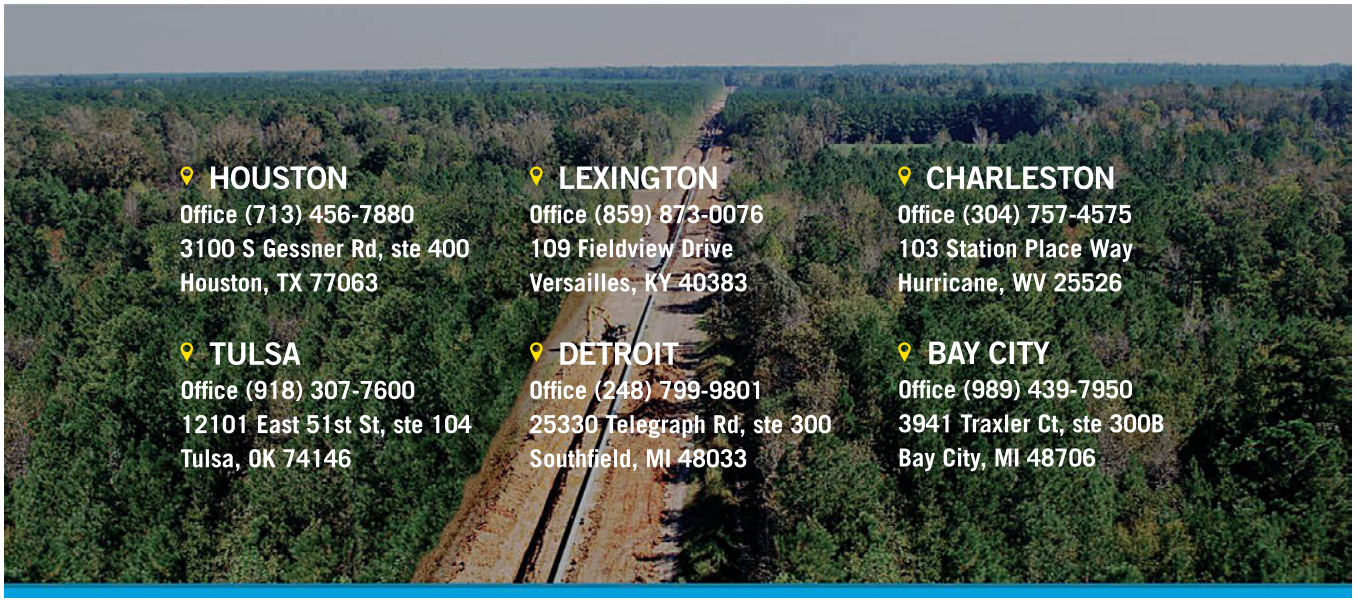

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Southern Gas Association

2015-2016 UPCOMING EVENTS

SGA EVENTS

Technical Conference On Environmental Permitting & Construction
February 2-4, 2016 • Savannah, GA

Supply Chain Management Conference
February 17-19, 2016 • Ponte Vedra Beach, FL

Spring Gas Conference and Expo
March 14-16, 2016 • Columbia, SC

Management Conference
April 6-8, 2016 • San Antonio, TX

Practical In-Line Inspection Workshop
May 3-5, 2016 • Tulsa, OK

Advanced In-Line Inspection Workshop
May 24-26, 2016 • Dublin, OH

Integrity Management for Gas Pipelines Workshop
June 8-10, 2016 • Houston, TX

Environmental, Safety & Health, and Training Conference
June 13-15, 2016 • Baltimore, MD

GMRC EVENTS

Guidelines for High Speed Package Compressors
March 1-3, 2016 • Houston, TX

Factors In Compressor Station Design
March 1-3, 2016 • Houston, TX

Engine Emissions Stack Testing & Analyzer Workshop
April 26-28, 2016 • Pittsburgh, PA

Gas Machinery Conference
October 2-5, 2016 • Denver, CO

- The GMC 2016 Conference has issued a Call for Papers and will begin accepting abstracts on December 1, 2015. Please visit the GMC website (http://www.gmrc.org/gmc) for information.

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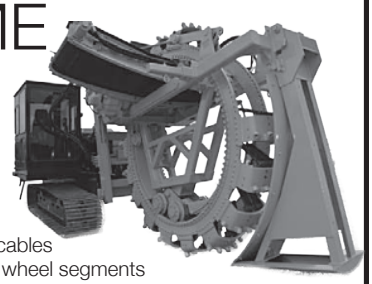

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November 2015

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A. Please select your job title/function:

80 ☐ Engineer
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84 ☐ Manager
85 ☐ Superintendent
86 ☐ Foreman
87 ☐ Financial
81 ☐ Sales, Marketing
82 ☐ Buyer, Purchaser
88 ☐ IT
89 ☐ Consultant
99 ☐ Other (Please Specify): _____

B. Please check the category which best describes your company's activity.

60 ☐ Gas Utility (LDC) (Distribution)
61 ☐ Gas Pipeline (Transmission)
62 ☐ Integrated Gas Utility & Gas Pipeline (Trans. & Dist.)
63 ☐ Pipeline other than Gas
64 ☐ Underground Gas Storage
65 ☐ Electric Utility, Combined Gas/Electric Utility
66 ☐ Gas Marketing, Sales, Energy Management
67 ☐ Gas Producer, Processor, Gatherer, Refiner
68 ☐ Industrial End User
69 ☐ Generator, Cogenerator, Non-Gas/Electric Utility
70 ☐ Gas Distribution Contractor, Subcontractor
71 ☐ Mainline or Pipeline Trans. Contractor, Subcontractor
72 ☐ Engineering or Engineering Consulting Firm
73 ☐ Equipment Manufacturer, Service and/or Supply Co.
74 ☐ Financial Services, Analyst, Legal, Insurance
75 ☐ Government, Regulatory, Research Agency, Educational Institute, Industry Association
99 ☐ Other (Please Specify)

_____

C. Are you involved in:

A ☐ U.S. Operation B ☐ Non-U.S. Oper. C ☐ Both

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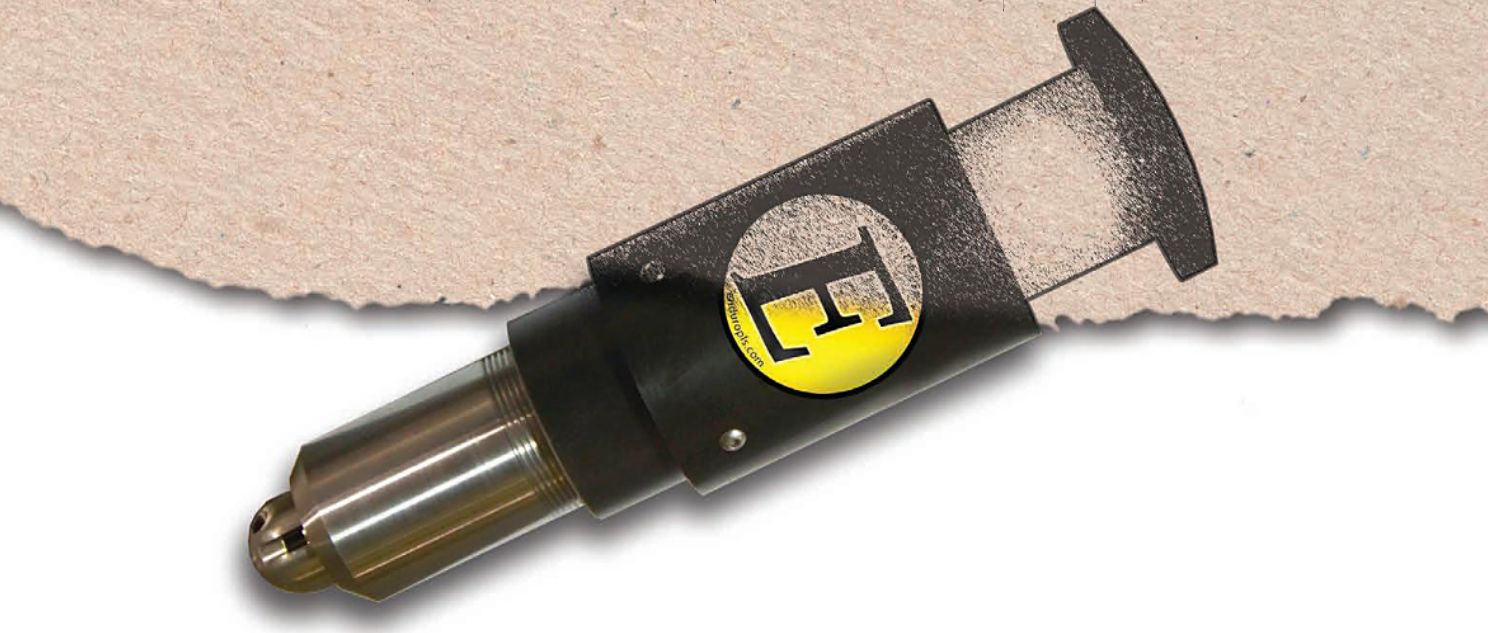

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