LNG North America

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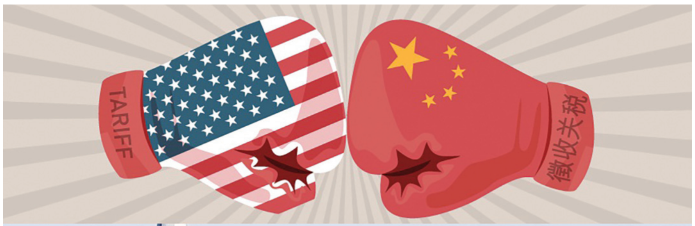
China keeps LNG out of a trade war with the U.S.



Despite harsh rhetoric, both China and the United States can still avoid a damaging trade war, industry participants hope. Strikingly, China has not included US agricultural products and LNG on a list of possible traffic, signaling the importance of natural gas in the power sector as Beijing strives to reduce air pollution.

Beijing's move to exclude US LNG from list of additional tariffs to be levied on U.S. imports clearly shows that natural gas is seen as an essential good, and in the event of an escalation Wood Mackenzie expects LNG to remain outside the bounds of any additional tariffs.

"Tariffs on US LNG would increase costs and potentially limit availability of LNG. CNPC recently signed two long-term deals with Cheniere, one of which starts in 2018. For flexible US volumes, the introduction of tariffs would have posed a significant challenge for Chinese buyers as they seek to meet surging demand. It would also have created logistical headaches for suppliers to optimise their portfolios to ensure they could meet Chinese demand while redirecting US LNG to other markets", commented Nicholas Browne, head of Asia-Pacific gas and LNG at Wood Mackenzie.

In terms of energy, the list from the Chinese government includes nearly all commodities covered by Chapter 27 of the Harmonized System of customs codes. This chapter covers mineral fuels, mineral oils, bituminous substances, and mineral waxes. LNG seems to be clearly excluded from the list of goods that will face tariffs as the list jumps from code 27109900 (waste oils) to 27111200 (liquefied propane), excluding 27111100 (LNG). Natural gas in a gaseous state (27101210) is however included but of no significance given China cannot import pipeline gas from the US.

The exclusion of LNG is not surprising, in Browne's view, given the rapid growth of China's LNG demand and the fact that the US will be the key source of incremental supply growth in 2018 and 2019.

The success of China's coal to gas switching policy led to a very

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LNG Canada partners about to select EPC contractor

Skepticism abounds if the LNG Canada projects will ever be built in British Columbia but Shell Canada's President Michael Crothers is adamant that project partners want to start construction at the end of this year. Seeking to swiftly monetize Canada's abundant natural gas reserves, JV partners are going through a process with two remaining EPC contractors who are bidding for the scope of work at the liquefaction plant in Kitimat.

"We'll be working with the final bidder to come to a final price and only after that will our joint venture companies – Shell, PetroChina, KOGAS and Mitsubishi – assess the competitiveness of the project and then we will come to the FID," said Shell Canada's president and country chair, Michael Crothers.

Pointing out site advantages, Crothers listed Kitimat's deep water channel, existing jetties, access to hydropower and rail supply – a site that is only 8 days shipping distance from Asian markets compared with sites dependent on the Panama Canal route which is at least 3 weeks, and prone to congestion.

"And then we have vast gas supply in the Montney that is potentially stranded and at risk because of US

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AGENDA

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tight winter gas market in 2017/18 and gas shortages in the northern provinces. LNG was instrumental in limiting shortages and demand grew by a record 12 million tonnes in 2017 to reach 38 million tonnes. US LNG met 1.6 million tonnes, or 4% of China's LNG demand last year, according to Wood Mackenzie figures.

With coal to gas switching continuing at a rapid rate, LNG demand growth in 2018 is forecast to be at least 10 million tonnes to reach 49 million tonnes. "We currently forecast demand will grow an additional 9 MT in 2019 to reach 58 MT. We forecast that US LNG will account for 30% of incremental global LNG supply growth this year and 45% in 2019," Browne said.

Tariff on oil would hit US exporters

Taking a tough stance on oil, China earlier threatened to tariffs on imports of crude oil and refined products from the United States.

Beijing's drastic response came just hours after Trump released a list of $50 billion worth of Chinese goods subject to tariffs. The inclusion of energy tariffs took analysts by surprise given that previous tariff threats had largely focused on automobiles and agriculture. Hitting back, the Chinese government said it will levy a first round of tariffs on $34 billion worth of U.S. cars an agriculture products, starting from July 6.

At a later stage, another $16 billion in natural resources will be subjected to tariffs from China. If enacted, these tariffs would jeopardize growth in U.S. shale oil and gas production as China has emerged as one of the largest buyer of U.S. crude oil. According to EIA figures, China currently imports about 363,000 barrels of U.S. crude daily in Q1-2018, on par with Canada.

China is a significant outlet for US crude and WoodMackenzie says exports would be much higher in Q2 2018 given the lower WTI-Brent differential which made the arbitrage to Asia look more attractive. Sanctions might change everything, and while China could secure the crude from alternative sources such as West Africa which has similar quality as the US crude, the United States would find it hard to find an alternative market that is as big as China. ■

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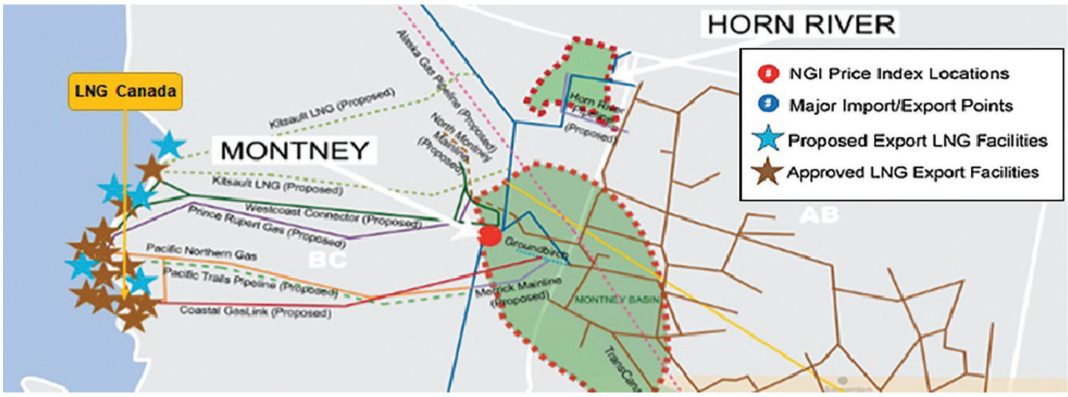
shale gas developments that is eroding some of the Canadian markets," he added, pointing out the potentially huge, cheap resource base in north-eastern BC.

Asked about the timing of a financial close, Crothers was seeking to buy time. "At this point we actually don't have a definitive timeline. "Shell has never committed to a FID by the end of this year. Moreover, KOGAS and PetroChina are government organizations so they have their own process to follow," he said.

Strikingly, Shell's former rival Petronas joined the US$11 billion LNG Canada project in early June – just a year after the Malaysian company cancelled its C$36 billion Pacific North West project.

Cost concerns remain

Located at Kitimat, the LNG Canada liquefaction plant is expected to cost around US$11Bln using modular construction meth-



ods. Additional costs will include feed-gas supplies and an investment in the multibillion-dollar TransCanada pipeline project, the Coastal GasLink.

Though Petronas' move to join the LNG Canada venture helps accelerate the project, costs will remain a major concern of the project. Wood Mackenzie senior analyst Prasanth Kakaraparthi advised the companies to take advantage of the latest tax breaks announced by the government of British Columbia.

As a sweetener to get some of Canada's much delayed LNG export ventures off the ground, the Government of British Columbia has offered additional project incentives amounting to US$4.8 billion in provincial income, sales and carbon tax cuts to build the facility. In BC province, around 20 LNG export ventures had been in the making a few years ago, but following many cancellations there are now only two others moving forward, the small-scale Woodfibre LNG venture at Squamish and the Steelhead LNG venture on Vancouver Island.

Petronas, Malaysia's state oil and gas major, holds nearly 52 Tcf of reserves and contingent resources in Canada. "Consequently, monetisation through LNG is inevitable given the weak outlook for domestic prices," the WoodMac analyst commented.

Once the Petronas transaction is complete, the Malaysian company will hold 25% of the shares in the LNG Canada venture and Shell will be operator with 40%. The other stakeholders are PetroChina and Mitsubishi of Japan each with 15% and Korea Gas Corp. will own 5%.

Market tightening

Looking ahead, Petronas has signalled its intent to become a portfolio player and has taken steps to diversify its supply sources. According to Wood Mackenzie calculations, once both phases are executed LNG Canada could add up to 7 million of equity LNG into Petronas portfolio – nearly 20% of its 2023 supply.

"Petronas is in Canada for the long-term and we are exploring a number of business opportunities that will allow us to increase our production and accelerate the monetisation of our world-class resources in the North Montney," said Petronas President and CEO Wan Ariffin. "LNG is just one of those opportunities."

Should LNG Canada eventually get off the ground Wood Mackenzie analysts believe this to be a positive development for Petronas, Kakaraparthi said, adding. "We expect the global LNG market to tighten post 2022 and this bodes well for the project."

However, fresh activity has returned to the LNG space with a number of projects expecting to take FID ahead of 2019. A new wave of project sanctions and rising oil prices could push up project costs and dampen the economics. ■

LNG North America

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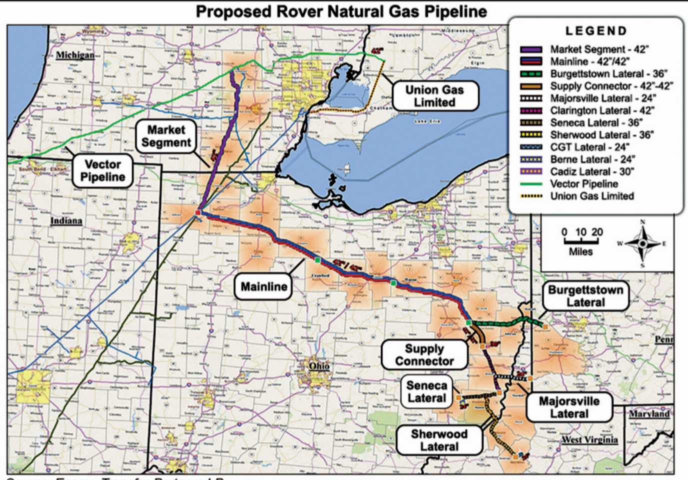
Awaiting new Appalachia takeaway capacity

U.S. gas companies have been persistently waiting for new Appalachia takeaway capacity – notably the Rover Phase-2 pipeline – to come online this year so the region can provide the bulk of 2018's dry production growth. Analysts at the consultancy Energy Aspects anticipate output gains in the Lower 48 will grow by 7.3 bcf/d year-on-year, of which 4.0 bcf/d is scheduled to come from Appalachia region.

Proposed Rover Natural Gas Pipeline



Source: Energy Transfer Partners LP

Anticipating delays to the full start-up of the critical Rover Phase-2 pipeline, analysts cautioned that this growth is likely to be back-loaded, with annual growth in H2-2018 forecast to be 4.6 bcf/d.

Imminent start-up of Atlantic Sunrise

The stated 'mid-2018' start-up for the 1.7 bcf/d Atlantic Sunrise gas pipeline appeared on track at Williams Q1 18 earnings call in early May, which described the pipe as 70% complete. Williams said weather conditions would be key to exactly when the pipe enters service. On 18 June, Williams/Transco requested to pursue extended hour works—24/7 for 7-10 days—to complete the Pequea Creek crossing in Lancaster County, Pennsylvania. It requested approval of the request by 20 June, so a timely start-up of Atlantic Sunrise seems likely.

In contrast to Atlantic Sunrise, "the project that appears far more unlikely to meet its expected in-service date is Mountain Valley," Energy Aspects suggested. The project's 2.0 bcf/d in takeaway is due to come online in Q4 18, yet ongoing legal delays, erosion control problems, and a fierce public protest movement have caused weeks of construction delays that pose a significant risk to its timeliness.

"The potential for delay to either pipe could weigh on later year Appalachia growth figures, which would dampen the 7.3 bcf/d in average annual 2018 y/y uplift from total US production," analysts cautioned.

Shifting sands

New Appalachia pipelines tend to be initially utilised by flows shifted from other pipes, in combination with some minor organic growth. This was the case in early January when Leach XPress came online between West Virginia and Ohio. Leach saw 1.0 bcf/d in flows in January, its first month of operations. However, deliveries onto the Rockies Express Pipeline originating in Ohio fell by 0.2 bcf/d the same day Leach entered service, and declined by the same amount throughout January. The Texas Eastern pipeline network saw its Ohio deliveries fall by 0.6 bcf/d m/m as Leach came online.

"We estimate that only 0.2 bcf/d in Leach flows were new gas in its first few months of service, proving that the new pipe failed to boost Appalachia output much despite Leach's 1.5 bcf/d in capacity," Energy Aspects said in a North America market commentary. ■

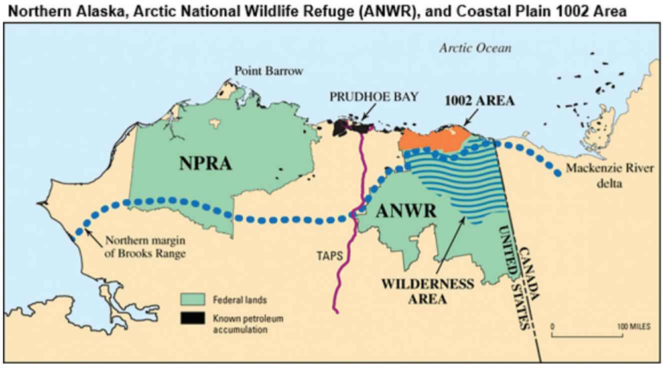
Trump administration opens up Alaska for oil, gas drilling

Developing Alaska's Arctic National Wildlife Refuge (ANWR) would substantially increase U.S. crude oil and natural gas production after 2030. The state of Alaska holds an estimated 36 billion barrels of crude oil and 137 trillion cubic feet of natural gas, so after the Trump administration lifted an ANWR drilling moratorium in December 2017, wildcatters are rushing north to tap America's Arctic resources.

Situated on the northern coast of Alaska east of Prudhoe Bay, ANWR's native lands in the coastal plain hold a mean estimate of 10.4 billion barrels of crude oil, as assessed in the United States Geological Survey (USGS). Yet, upstream activities had been effectively banned before December 2017, when the area was under a drilling moratorium.

Things changed when the passage of Public Law 115-97 required the U.S. Secretary of the Interior to establish and administer a competitive program for the leasing, development, production, and transportation of oil and natural gas.

Northern Alaska, Arctic National Wildlife Refuge (ANWR), and Coastal Plain 1002 Area



To reach peak production, fields are assumed to take three to four years. They maintain peak production for three to four years, and then to decline until they are no longer profitable and are abandoned.

Start of production not until 2031

The effect of this law on U.S. crude oil production is reflected in three resource estimate values — low, mean, and high —in the EIA's Annual Energy Outlook 2018. In all three cases, production from ANWR does not start until 2031 because of the time needed to acquire leases, explore, and develop the required production infrastructure.

In the Mean ANWR case, cumulative U.S. production from 2031 through 2050 is 3.4 billion barrels higher than in the AEO2018 Reference case. From 2031 through 2050, cumulative U.S. production is 5.1 billion higher in the High ANWR case and 2.0 billion barrels higher in the Low ANWR case than in the AEO2018 Reference case.

To bring the oil bounty to market, Alaska relies on the Trans-Alaska Pipeline System (TAPS) which transports crude oil from the frozen North Slope to the warm-water port at Valdez on the state's southern coast. Capacity reached a peak flow in the late 1980s at 2 million barrels per day (b/d); current flow is nearly 500,000 b/d. ■

Woodside ponders pulling out of Port Arthur LNG

Woodside Petroleum is close to making a decision about whether to continue to invest in Sempra Energy's Port Arthur LNG project in Texas. Speaking at the World Gas Conference in Washington, Woodside CEO Peter Coleman put into questions the adequacy of return from any financial involvement in the venture.

"We've got to make some decisions pretty soon about our continued pursuit with Sempra. We don't have an investment in (Port Arthur), what we've been doing is just paying our way, and whether that is going to give us an adequate return – I would say today that is very challenged," Coleman said.

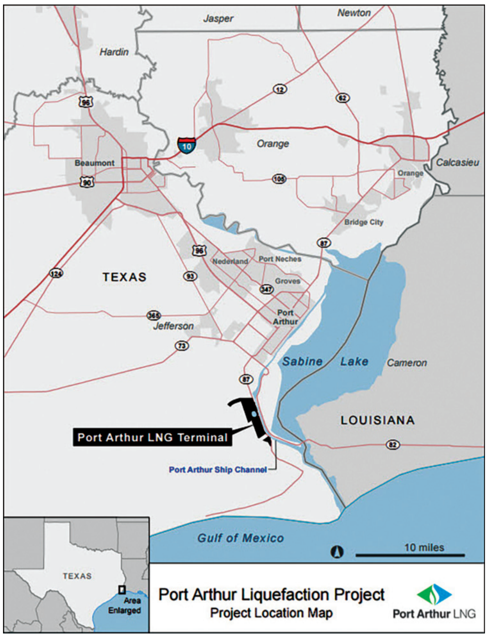
Woodside Petroleum operates the North West Shelf plant and Pluto LNG and is a shareholder in the Wheatstone plant in Western Australia. Coleman sees "real appetite for gas in Asia" hence LNG should be the first choice given that an import terminal that links to a 'virtual pipeline' of shipped LNG ensures resilience.

Dismissing investment in strategic natural gas pipelines as "an illusion of security of supply," the Woodside CEO said "sinking funds and time in laying a pipeline delivers dependence and limits choice." Woodside has substantial stakes in three Australian LNG export plants.

"Just look at what's happening in the Netherlands, where the steep decline in production from the Groningen field due to seismic activity poses serious challenges. Or in China, when demand for gas was peaking during winter, Turkmenistan reduced pipeline gas volumes into the country," he noted.

The maturing of LNG trade allows buyers to get the supply they need - and secure it on flexible terms and at a competitive price. Woodside considers itself a frontrunner in "transitioning from long-term contracts to more flexible arrangements that hold appeal for buyers who are looking to wean themselves off coal." Moreover, the versatility of LNG makes it an ideally suited to complement renewables, or as a transport fuel in shipping and trucking. ■

Render of Port Arthur LNG project



Sempra selects Technip and Kiewit for EPC of Costa Azul LNG

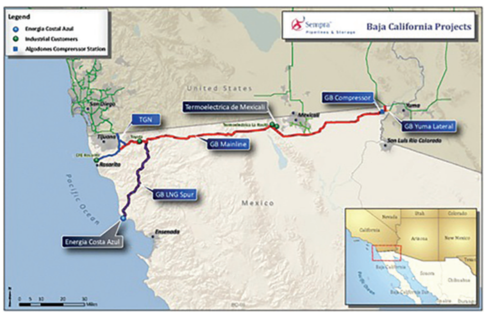
The TechnipFMC-Kiewit partnership has selected as EPC contractors for transforming Sempra Energy's LNG import terminal at Costa Azul in northern Mexico into a medium-scale export plant. The project will be built under a lump-sum EPC contract.

"The Energía Costa Azul (ECA) project is one of three North American LNG export projects we are developing, two on the Gulf Coast and one in the Pacific Basin, to help meet global demand for LNG," Sempra Energy COO Joseph A. Householder, said, adding the Costa Azul project was "geographically well positioned to serve Asian gas markets."

The Costa Azul terminal, situated on the Pacific Coast of in northern Mexico, has entered service in 2008 initially as an LNG import plant. Sempra said the Costa Azul liquefaction and export project is being developed to provide customers with direct access to West Coast LNG supplies.

In Mexico, the California-based utility Sempra energy is acting through the subsidiary Infraestructura Energetica Nova (IEnova). It is looking to develop another small-scale plant in Mexico in with 2.5 mtpa of output, delaying plans for a 12 mtpa facility.

In southeast Texas, Sempra is planning to build a LNG export plant along the Sabine-Neches Waterway at Port Arthur with Woodside Petroleum as one of its partners. ■



NEWS NUDGES

Texas LNG to take FID in 2019

The Texas LNG Brownsville, a liquefaction and export venture on the Gulf of Mexico in South Texas, is making progress in its permitting process to produce an initial 4 mtpa. The project developers said full FERC approvals and a final investment decision (FID) are expected in 2019 and with first production scheduled for 2023. Detailed engineering and other pre-FID activities are continuing through the rest of 2018 upon closing of its current funding round.

First gas enters Corpus Christi LNG

Cheniere Energy is advancing the first two trains at the $13 billion Corpus Christi liquefaction and export project in Texas, with first gas having been fed to Train 1 as of mid-June. Commercial start-up of the plant, however, is still at least six months off. The first two Corpus Christi Trains are about 87% complete. According to Cheniere, trains one and two are set to enter service ahead of schedule in the first and second halves of 2019.

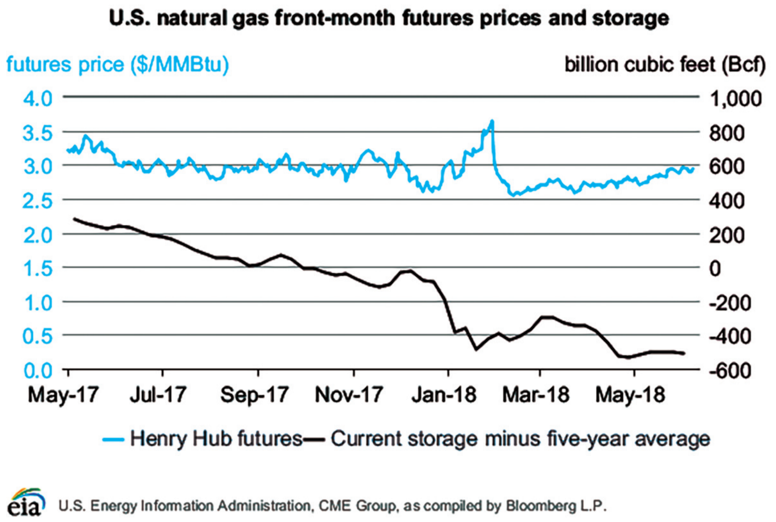
The first two Trains are fully contracted and Train 3 is partially contracted. Customers include Australia's Woodside Petroleum and Frances's EDF, Spanish energy companies Endesa, Iberdrola and Gas Natural Fenosa as well as Pertamina of Indonesia. Any excess capacity not sold under long-term sales agreements will be available for Cheniere Marketing to sell. ■

EIA expects Henry Hub price rebound to $3.08 in 2019

Dry natural gas production in the United States is about to reach a fresh record of 81 Bcf per day, spurring LNG export growth and pushing down prices this year. According to the U.S. Energy Agency (EIA), Henry Hub prices are forecast to average $2.99/MMBtu for the full year 2018, but notch up to $3.08/MMBtu in 2019.

In the agency's latest Short-Term Energy Outlook (STEO), the Q2 Henry Hub natural gas spot prices is seen drop 1 cent to $2.84/MMBtu, while the Q3 forecast also fell 1 cent from the previous month to $3.01/MMBtu.

Currently, a large working natural gas inventory deficit and the late start to the storage injection season contributed to higher Henry Hub prices despite record production growth (see graph). The Henry Hub natural gas spot price averaged $2.80/MMBtu in May, when dry gas production was up 13% higher year-on-year. The EIA projects dry gas production to increase by 10% in 2018 and by 3% in 2019.



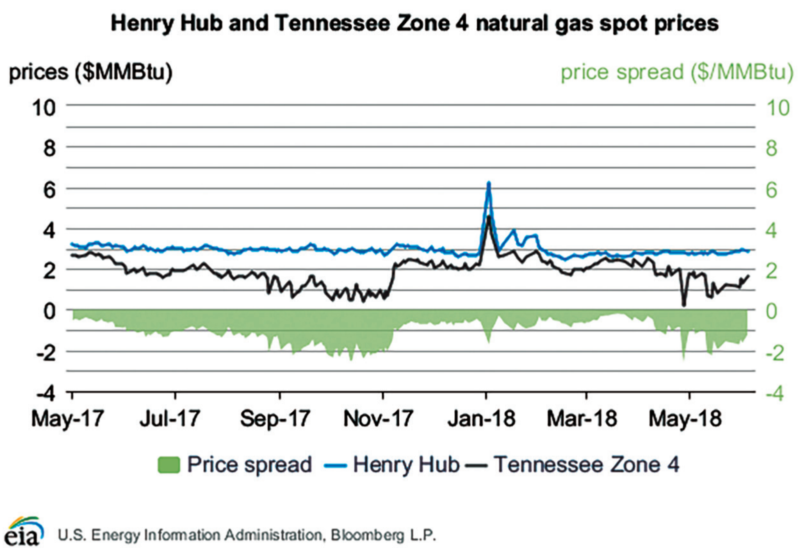
LNG exports poised to surge

"Increased production and added infrastructure have positioned LNG exports for considerable growth in 2018 and 2019," commented EIA Administrator Linda Capuano. In its June outlook, the EIA further increased the forecast for dry gas production this year. "We now expect production to increase by more than 10% from 2017, reaching a record 81 Bcf in 2018," she said.

As the shale gale sputters on, the continuous rise in production is paving the way for US LNG exports to top 3 Bcf/d in 2018 and 5 Bcf/d in 2019. Assuming the EIA's June forecast holds, US exports of LNG will more than double over a 24-month period.

Cove Point LNG, the Dominion Energy-led export venture in Maryland, is ramping up fast. In April, the facility exported an estimated 13.4 Bcf, implying baseload utilization of 65% and, in May, it exported an estimated 23.5 Bcf, implying baseload utilization of 94%, the STEO report reads. And more liquefaction and export plants come on stream in the southern states, including Georgia, Louisiana and Texas.

By 2021, the U.S. is expected to add 6.05 billion cubic feet per day of new liquefaction capacity in addition to 3.5 Bcf/d already in operation at Sabine Pass and Cove Point. According to the EIA, "Before the end of 2018 the Elba Island liquefaction project in Georgia is expected to commission the first 6 of 10 small modular liquefaction units, with a combined capacity of 0.2 Bcf/d. "New trains at Cameron, Freeport, and Corpus Christi - plants under construction along the US Gulf Coast - are expected to be commissioned in the next three years." ■



NEWS NUDGES

Cove Point pricing

The Intercontinental Exchange (ICE), has launched a physical trading product to reflect the change at the Dominion Energy Cove Point LNG facility in Maryland from an import terminal to an export plant. The new product reflects the physical market for gas deliveries into the liquefaction plant. The previous Cove Point market, which had been set up for receiving natural gas from LNG imports, was delisted simultaneously by the ICE. The new Cove Point price was last at $3.110 per million British thermal units.

Alaska gas pipeline

Alaska Gasline Development Corp., the state body leading the Alaska LNG project, said the US Army Corps of Engineers has released a final environmental impact statement for Alaska's stand-alone pipeline project. The Alaska pipeline will be 733 miles long and connect a conditioning facility at Prudhoe Bay in North Alaska to the city of Fairbanks. Design work began in 2010 to address potential gas shortages in Alaskan towns and cities.

US exports rise

US LNG exports increased to five cargoes with carriers carrying a combined 18.7 Bcf of natural gas having departed from the United States from June 14 through June 21. Three carriers left from the Sabine Pass plant in Louisiana and two from the Cove Point terminal in Maryland, according to the EIA. Spot prices rose at most locations, with the benchmark Henry Hub at $2.95/mmBtu. Total US natural gas consumption, led by electrical power generation needs, rose by 4%. "Net injections to working gas totaled 91 Bcf for the week. Working natural gas stocks are 2,004 Bcf, which is 27% lower than the year-ago level and 20% lower than the five-year average," said the EIA. ■

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Qatar Petroleum acquires stake in Exxon's shale assets in Argentina

Gaining access to shale assets in Argentina, Qatar Petroleum has acquired a 30% stake in ExxonMobil's prolific Vaca Muerta oil and gas play in the onshore Neuquén basin in Argentina. The deal is hoped to bring fresh drive to shale drilling in Argentina which had been rather slow due to local price controls for natural gas. However, President Mauricio Macri's right-of centre government lately doubled wellhead gas prices for existing fields and introduced incentive prices for new developments.

Vaca Muerta, a shale formation in west-central Argentina, is estimated to hold 22.8 barrels of oil equivalent (boe) which makes it one of the largest shale rock formations in the world.

The Argentine shale deal between two of the world's largest oil producers comes as Exxon CEO Darren Woods seeks to tap fresh financing from external partners in order to swiftly expand upstream operations. The agreement was signed in Doha on Sunday but both parties did not disclose the value of the investment.

Participation of Qatar Petroleum in the Vaca Muerta play is hoped to bring new drive to ongoing operations. These shale blocks are currently under "unconventional exploration licenses with active drilling plans as well as exploitation licenses with pilot drilling and production," the two partners stated when signing the deal.

"This is an important milestone, as it marks Qatar Petroleum's first investment in Argentina as well as its first significant international investment in unconventional oil and gas resources," CEO Saad Al-Kaabi said in a statement. The accord gives Qatar Petroleum a 30% shareholding in Exxon's two local affiliates in Argentina – ExxonMobil Exploration Argentina S.R.L. and Mobil Argentina S.A. – which together with other partners hold rights for seven shale blocks.

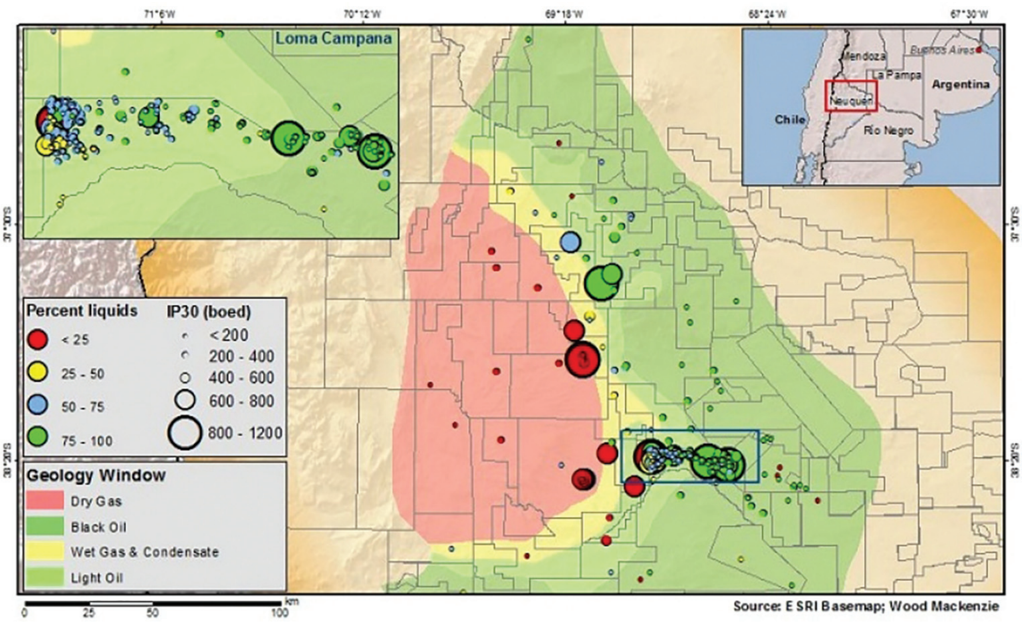
Al-Kaabi explained the venture into Argentine shale oil and gas production would help expand the international footprint of the Qatari state oil company. At home, Qatar Petroleum is planning to boost local production from the North Field in a bid to raise its LNG production from 77 million to 100 million tons per year (mtpa).

Incentives for new shale developments

Situated in Neuquén in the western part of Argentina, Vaca Muerta shale is considered among the most prospective unconventional shale oil/gas plays outside North America. ExxonMobil claims activity in the basin has picked up r ecently thanks to unspecified "governmental incentives", however, progress had been slowly forthcoming for years given that the Argentine government had been keeping a lid on domestic gas prices.

President Mauricio Macri's government, since taking to power in late 2015, is now trying to boost domestic oil and gas production in an effort to reduce costs for energy imports. Macri's right-of-center government introduced an incentive price of $7.50/MMBtu for output from new developments back in 2013 and doubled average wellhead gas prices to $5.20/MMBtu on average for existing fields. This incentive price helped advance production which rose by 6.6% last year – much of the new growth came from shale and tight plays like Vaca Muerta and Mulichinco.

Other oil majors are also eying Argentine shale plays: When BP was revising its current engagement in the US Permian basin it had been considering investing in Argentina. "There is enormous potential," CEO Bob Dudley said with reference to recent reforms that made Argentina more attractive by simplifying the market entry of foreign companies. ■



Source: E SRI Basemap; Wood Mackenzie

U.S.-Canadian energy trade balance remains lopsided

Canada, the largest energy trading partner of the United States, consistently exceeds the value of U.S. energy exports to Canada by a large margin. According to EIA figures, energy accounted for $73 billion, or about 24%, of the value of all U.S. imports from Canada in 2017, while Canada merely imported energy worth $18 billion from its southern neighbour.

Canada is the main source of U.S. energy imports and the second-largest destination for U.S. energy exports behind only Mexico. Most of the bilateral trade of natural gas is done through pipeline shipments. Most of Canada's gas exports to the United States originate in Western Canada and are shipped to U.S. markets in the West and Midwest. Imports of Canadian gas increased to 8.1 billion cubic feet per day (Bcf/d) in 2017, making up 97% of all U.S. imports. Total 2017 gas imports from Canada were valued at $7.3 billion.

On the flip side, U.S. gas exports to Canada increased to 2.5 Bcf/d in 2017 and were mainly routed from New York into the eastern provinces. Build-out in gas pipeline capacity help ship supply from the Marcellus and Utica shale formations into Canada.

Crude oil dominates the trade balance and Canada provided 43% of of total U.S. crude oil imports in 2017, which equals an average 3.4 million barrels per day (b/d). Canadian crude oil is largely produced in Alberta and consists mainly of heavy grades that are shipped primarily to the U.S. Midwest and Gulf Coast regions. The value of Canadian crude oil exports increased to $50 billion in 2017, as a result of both rising oil prices and an increase in volume. ■

How analytics are giving LNG process industries the edge

Unplanned downtime can cost an LNG facility as much as $4 million per day. With potential costs so high, profitability is largely linked with unplanned downtime. According to GE Power estimates, unplanned shutdowns in the process industry globally cost 5% of total annual production — that's as much as $30 billion a year.

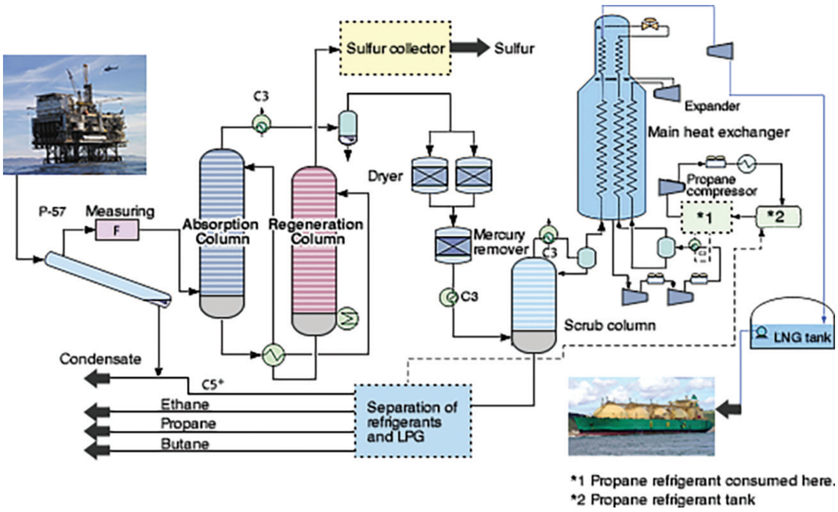
The reliability of electric rotating machines (ERMs) is key to minimise this risk. Traditionally, vibration sensors have been used to detect ERM failures, however their cost, both from a material and a deployment perspective, mean they are used for only the most critical machines – and they only detect mechanical failures, not electrical ones, which limits their impacts.

"Industries are under pressure from narrowing margins, stiffer competition and fragmented processes. Used intelligently and backed by technical expertise, I believe digital APMs can be an indispensable ally in the push for productivity and profitability, allowing companies to become leaner and more resilient," said Azeez Mohammed, president & CEO, GE's Power Conversion business.

Over the past few years drive technology has significantly evolved. Today, each drive possesses one or several processors and today's drives have more enhanced computing capabilities to do high-speed control, data gathering and self-diagnosis. That processing power, sitting "at the edge," leaves huge and yet untapped potential for predictive analytics and improving performance.

Effective digitized ERM adds value by identifying any degradation issues early and before a failure strikes, so operators can take action to mitigate problems before they occur and perform maintenance in a predictive manner, Mohammed explained. Having predictive foresight of failures, both for ERMs and drives, means being able to automate the ordering and replacement of parts, therefore eliminating the need to tie up capital in costly inventory – and an APM could even provide crucial data to a company's supply chain that informs factory acceptance tests and minimizes the risk of poor performance when new machinery comes online.

Process plants - such as LNG export facilities - usually encompass a large variety of rotating machines and drives technologies, so over time, a digital blueprint of these assets can be created to monitor performance and check the quality of new units, Mohammed suggested. "At GE, we have designed APM algorithms for both ERMs and drives that draw on our vast data lake to deliver accurate analytics – with no costly vibration sensors required. This solution is already being developed across various industries, including metal plant, refinery plant and the navy," he said. ■



Steps of the LNG production process

Uniper to widen LNG supply operations for power producers

Shifting tact, Uniper CEO Klaus Schäfer has announced plans to expand the utility's business supplying LNG to power generators in South America, Middle East and Asia. Speaking to investors he was adamant about Uniper's aim to "remain independent" even after Fortum of Finland will acquire a significant stake in the German utility.

Going forward, Uniper's strategic marketing will focus on providing energy solutions for power stations, industrial facilities, electricity grids in the Middle East, the Americas and Asia as well as in Europe. "In short, the regions that import LNG as a fuel for power generation," Schäfer said.

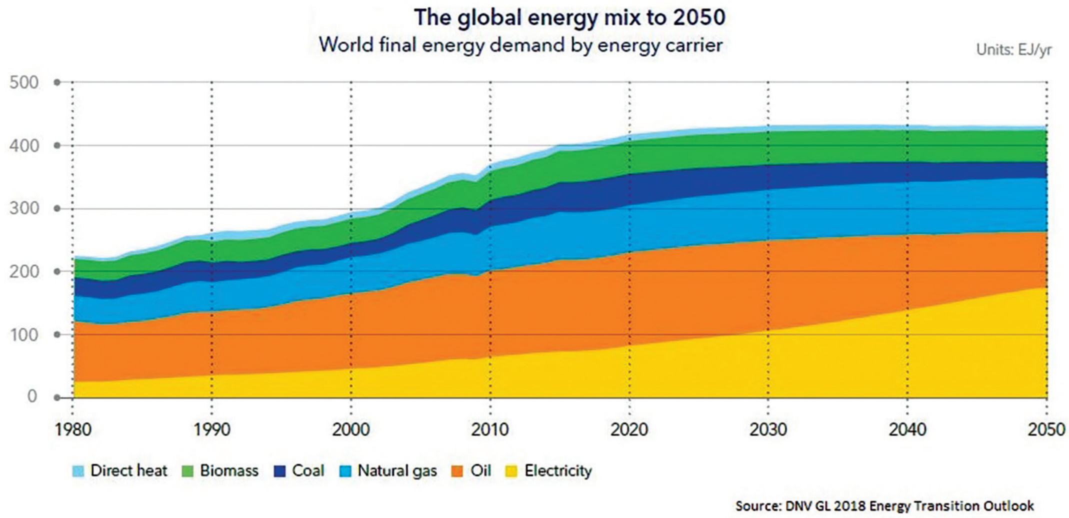
The midstream gas business is poised to remain a key area of growth for the company, he forecast, outlining that Uniper aims to grow both regionally and globally, notably in terms of its LNG portfolio.

Commenting on the imminent closure of Fortum's acquisition of 47.12% of Uniper from E.ON in the weeks ahead, Schäfer said: "The task will then be to reach an agreement with our new major shareholder that reflects the interests of the company, its employees, and the other shareholders ... but I'd like to state clearly that this wouldn't in any way alter our intention to remain an independent company."

Talking to shareholders on Wednesday, the Uniper CEO stressed the company had met key 2017 financial targets notwithstanding the absence of some earnings streams, adverse foreign exchange rates and the late arrival of cold temperatures in Europe during the past winter. ■

Gas to overtake oil as world's primary energy source in mid-2030s

Nearly two-thirds of oil and gas sector leaders, surveyed by the Norwegian classification society DNV GL, plant to boost spending on gas projects in 2018, with gas expected to overtake oil as the world's primary energy source in the mid-2030s. Thereafter, the energy transition will enter its final phase-out of fossil fuels, with hydrogen and renewables set to gain momentum.



The latest DNV GL Energy Transition Outlook, launched today at the World Gas Conference in Washington, DC, singles out the global energy transition as the primary driver for investment in natural gas and LNG projects this year. Investment in gas upstream, midstream and power plant projects will accelerate in the early-2020s as major oil companies decarbonize their business portfolios.

The pace with which industry players are moving, however, differs by region: Just a third of survey respondents in North America (33%) say that their company is actively preparing for the shift to a lower carbon energy mix this year, compared to more than half (51%) in Middle East and North Africa.

Peak gas by mid 2030s

Natural gas is forecast to be the largest source of energy from around 2035 but demand will peak soon afterwards – well after the use of each of the other fossil fuels has gone into long-term decline.

"With reliable supply and affordable cost we expect solid growth of gas for the next 15 years. After peaking in the mid-2030s, gas use in the power sector is expected to decline from around 2040, by when wind and solar will dominate power supply," said Sverre Alvik, programme director for DNV GL's Energy Transition Outlook.

In Europe, gas demand has already peaked in 2010, and will do so by 2020 in North America; but in key regions such as South-East Asia and China it will only peak in the mid-2030s.

Citizens in Asia's growing middle class are aware of how diseases and death are caused by serious air pollution. According to KOGAS research engineer Kidong Kim, this has "increased people's resistance to coal thermal power plants and diesel-powered transport, including ships. We expect natural gas or LNG to replace these energy sources."

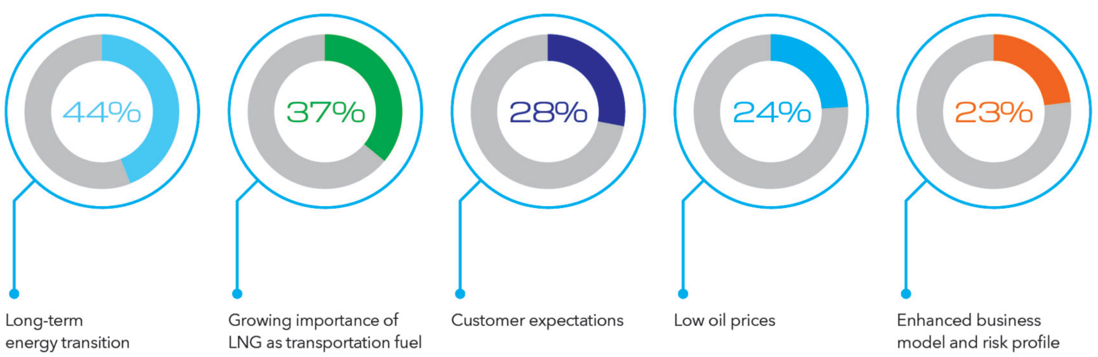
Renewables take over

Power generation is predicted to be the primary consumer of gas in most regions, though manufacturing could demand similar volumes in emerging markets. North East Eurasia and the Middle East and North Africa are seen increase gas output towards 2040 at least, overtaking North America as the world's largest gas producer. Production is also expected to double in China, the Indian Subcontinent and South East Asia.

Shell New Energies' executive vice president Mark Gainsborough noted: "We see the future for cost-effective and low-carbon power generation as renewables plus gas, that's something that is in the money now and needs to be built out pretty rapidly." The vast majority, or 72% of respondents, in DNV GL's survey agree with this view. They find that traditional power generation from coal will become obsolete over the coming decades, as the long-term attractiveness of gas improves significantly.

Pointing out risks in connection with the global energy transition towards natural gas, nearly a quarter of surveyed industry executives believe that onshore pipeline projects currently in development are adaptable enough to cope with potential long-term changes in the gas mix, such as greater variety of calorific values, hydrogen and biogas. ■

Top five drivers for investment in natural gas and/or LNG in 2018



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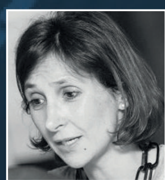

MARIA SICILIA
Director of Strategy
ENAGAS

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