LNG North America

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Exmar FLNG to help Argentina start first-ever LNG exports in 2019

Argentina's LNG export aspirations may soon be a reality as Exmar, the Belgian shipping firm, has entered a 10-year charter with YPF to deploy a floating LNG liquefaction vessel at Bahia Blanca, about 400 miles south of Buenos Aires. Operations are scheduled to start in Q2-2019, for the first cargo to set sail before year-end. The Exmar FLNG barge is expected to be a quicker route-to-market for excess production from the prolific Vaca Muerta shale gas field than a rival FLNG venture, under evaluation by Transportadora de Gas del Sur (TDS) and Excelerate.

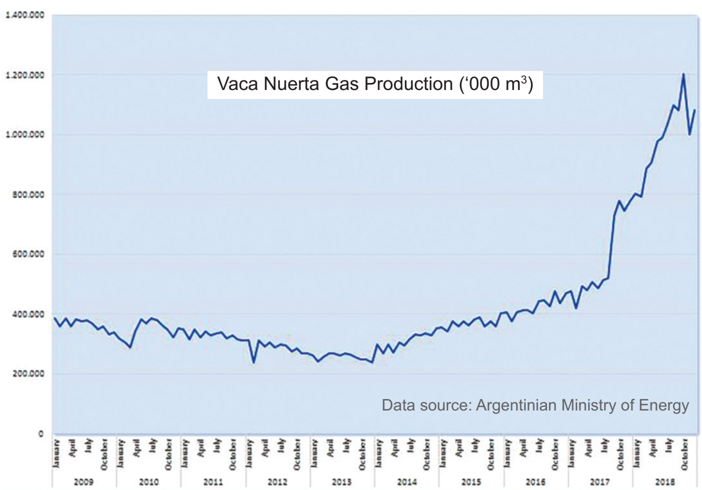
Striving for a 'fast-track monetization' of shale gas reserves, the Argentine government said the goal is to start exporting 40 million cubic metres per day, equaling 14.6 Bcm per year of LNG in 2023, and gradually increase that to 120 mcm per day, or 43.8 Bcm/y by 2025.

Exmar's FLNG barge, dubbed Tango FLNG, is envisaged to export 500,000 tons of LNG per year with up to eight cargoes meant to be produced over the ten-year period starting from winter 2019. The rival Excelerate/TDS project, in contrast, is still at an evaluation stage with the two project partner still studying the technical and commercial viability of liquefying and exporting excess shale gas during the summer season.

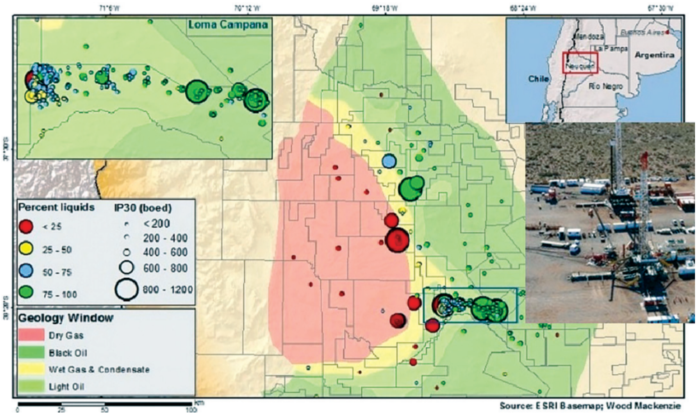
If realized, the Excelerate/TDS project will be built and operated under a 25-year license.

The ultimate aim is to reduce Argentina's gas imports, which are getting increasingly expensive amid a weakening Peso. But to reach this goal YPF would need to strike a binding agreement with Exelerate, and intensify efforts raise financing e.g. through a public-private partnership.

Critics are skeptical of Argentina's energy policy goals. "The government wants to attract as much investment as possible and feels it has to move quickly and drum up interest as long as interest rates are low. YPF cannot do it alone, especially with the Peso being so weak and




Bahía Blanca Gas Port



Argentina's credit history. Hence they are essentially copying the US model on shale oil and gas production," said LNG Unlimited analyst Alex Wilk. "Ultra-low interest rates are vital for sustained tight hydrocarbon production," he stressed; "But investors likely want to see opportunities for monetisation beyond the domestic market, where prices tend to be capped, and their banks presumably want a risk premium, hence the view to LNG exports."

Seasonal LNG exports of excess shale gas supply

The idea is to initially use the new LNG export plant mainly during the summer months to export Argentine gas that is not needed in the domestic market. This way, production growth of Argentina's prolific Vacca Muerta shale gas play could be sustained and expanded.

Peak gas demand in Argentina occurs during the Southern Cone winter, and in recent years the

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country heavily depended on spot LNG imports to meet its rising energy needs. But the Argentine government is keen to boost domestic production to reduce import dependency. Imports of spot LNG cargoes used to be mainly handled via a floating storage and regasification unit (FSRU), installed at Bahia Blanca in 2008 when Argentina started LNG imports. That very facility may now be converted into a liquefaction and export terminal.

Timeline for LNG exports may not be realistic

Observers doubt whether TDS and Excelerate's ambitious timeline can be realized. "Construction seems only scheduled to start in 2020, if investment is found and regulatory approval is granted," Wilk said, adding; "No contracts have been signed yet – neither with developers nor with buyers. "

Completion is envisaged by 2023. "If exports are done by converting an FSRU that timeframe looks realistic, but only if works start by 2020/21 and sufficient pipeline capacity from producing areas exist or is being built," he cautioned. Excelerate's next FSRU newbuild is understood to be already chartered to Gunvor, and there is a rumour that YPF will use its chartered GNL Escobar terminal, which could potentially free up FSRU capacity. The facility's initial capacity is advertised to be 40 million cbm/d – seemingly, "quite steep" and a bit too much given that a significant proportion of feedgas stems from volatile unconventional gas supply.

Aiming to become self-reliant on energy and fast-track LNG exports, the President of Argentina Mauricio Marci has courted the Emir of Qatar who came on a state visit in October. Assessing the status quo, Macri said: "From Qatar's perspective, things moved really well, as they are exporting to us an approximate value of $450 million, basically fuel." Argentina, in contrast, exported an approximate value of $20 million over the past few years, with around 70% related to agriculture and the rest in various industries.

"We are happy with this relationship," Marci told Tamim Bin Hamad Al Thani but noted Argentina is trying to limit LNG imports and become an energy exporter. To that end, the government imposed measures that will halt LNG imports and rely on domestic resources instead. Technically recoverable shale gas reserves are estimated at 308 trillion cubic feet, and supply is targeted to start flowing in large quantities from the Vaca Muerta area by 2022.

Qatar Petroleum, the Emirate's state-owned oil company, is keen to get involved in international oil and gas project beyond the Arab Gulf region and has been quick to purchase 30% of the hydrocarbon licences for seven blocks in the Vaca Muerta play, held by ExxonMobil. In 2017, Exxon started an exploration project in the area that involves the staged development of 300 horizontal wells with possible production of 11 million cubic metres per day. Plans to develop the Los Toldos I South Block were approved by the Neuquen regional government under a 35-year unconventional exploitation concession.

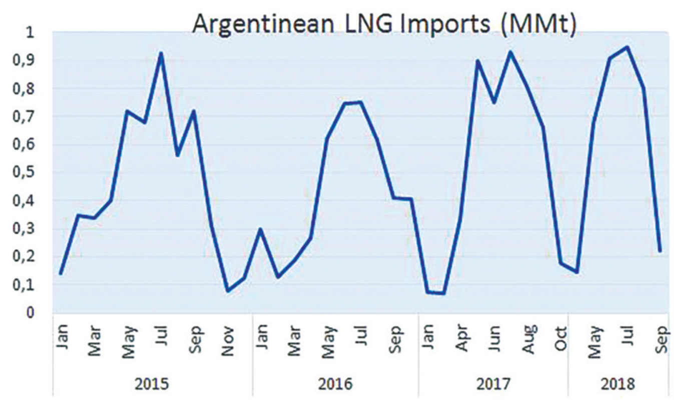
For Qatar, the purchase of part of Exxon's stake at Vaca Muerte is its first significant foray into unconventional oil and gas resource and its first investment in South America.

High hopes of replicating U.S. shale gale

Analysts assume Argentina might experience a boom in unconventional oil and gas, similar to the shale gas in North America. But for this to happen, Argentina would have to substantially step up exploration efforts to achieve some more significant volumes.

Output from Vaca Muerta is steadily rising and helps offset the falling supply from Argentina's maturing conventional gas fields. A staggering 243% jump in shale gas production to 25 million cubic meters per day (Mmcm/d) has pushed up Argentina's overall output of natural gas to 132 Mmcm/d in 2018. Technically recoverable shale gas reserves are estimated at 308 trillion cubic feet, and supply is targeted to start flowing in large quantities from the Vaca Muerta area by 2022.

But Argentina's shale industry is still in its infancy. Daily shale gas output in the U.S. is more a thousand times the volumes seen in Argentina. U.S. dry natural gas production is forecast to average 83.2 Bcf/d, or 2.36 Bcm/d in 2018, up 8.5 Bcf/d in 2017, according to the Energy Information Administration (EIA). So, there is still a very long way to go until Argentina's unconventional gas production will become anything like the American shale oil and gas revolution. ■



Commissioning cargo departs from Corpus Christi Train-1

The first commissioning cargo has loaded and departed from Train-1 at Cheniere Energy's Corpus Christi LNG export terminal in Texas. The LNG was loaded onto the 174,000 cubic metres capacity carrier "Maria Energy", charted by Houston, Cheniere's marketing unit.

Start-up of Train-1 marks the first export of LNG from the state and from a greenfield liquefaction facility in the lower 48 states. All three Corpus Christi trains combined will produce up to 13.5 mtpa.

The first two Trains are fully contracted and Train 3 is mostly contracted. Any excess capacity will be available for Cheniere Marketing to sell. Corpus Christi is being constructed at a cost of $15 billion. ■

Henry Hub spot price to soften in 2019

Strong, sustained growth in U.S. gas production is putting downward pressure on Henry Hub spot and futures prices. Dry gas production increased to 83.3 Bcf/d in 2018, according to figures by the U.S. Energy Information Administration (EIA), which forecasts a subsequent fall in Henry Hub spot gas prices to $3.11/MMBtu on average in 2019.

Bearish sentiment on gas futures prevails as dry gas production rose 8.5 Bdf year-on-year and might nearly reach 84 Bcf/d at the end of this years. "Both the level and volume growth of natural gas production in 2018 would establish new records. EIA expects natural gas production will continue to rise in 2019 to an average of 90.0 Bcf/d," the latest short-term energy outlook (STEO) reads.

Hence, the EIA's forecasts for Henry Hub 2019 spot prices are down 6 cents from the 2018 average and down from a forecast average price of $3.88/MMBtu in the fourth quarter of 2018. ■

LNG North America

Publisher
Stuart Fryer

Editor
Anja Karl
Tel: +44 7733 684682
anja@lngjournal.com

Layout
Vivian Chee
Tel: +44 (0) 20 8995 5540
chee@btconnect.com

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Vitol signs US LNG cargoes deal with Tellurian

Tellurian, the US LNG developer founded by ex-Cheniere CEO Charif Souki, has sealed a preliminary deal with Vitol to supply 1.5 mtpa of LNG cargoes for 15 years. The accord is for volumes from the Driftwood project, proposed for the Gulf Coast of Louisiana.

The transaction price is based on the Japan Korea Marker (JKM) price and on a free-on-board (FOB) basis whereby Vitol provides its own shipping.

Render of Driftwood LNG proje

Tellurian and Vitol have agreed to negotiate a future LNG sale and purchase agreement (SPA) subject to Tellurian's receipt of approvals from the Federal Energy Regulatory Commission (FERC) and a final investment decision (FID) to build the 27 mtpa Driftwood plant and an associated pipeline. Construction is scheduled to start in 2019 and commercial operations at the Driftwood plant are expected to begin in 2023.

"The LNG business is evolving into a true commodity market, which includes LNG purchases and sales based on actual LNG prices rather than indexing to other energy products," said Tellurian CEO Meg Gentle. "The JKM has emerged as the most liquid and transparent pricing mechanism for LNG."

Apart from selling LNG cargos, Vitol said it was evaluating a potential equity investment in the Driftwood Holdings partnership. "Tellurian's integrated Driftwood project offers a unique value proposition, which we are pleased to participate in as off takers and potential equity investors," stated Pablo Galante Escobar, Head of LNG at Vitol.

Vitol has also signed a supply agreement with Cheniere, the leading US LNG exporter. Under that deal, Cheniere's marketing unit will provide 0.7 mtpa for 15 years to Vitol on a FOB basis. The purchase price for the LNG was indexed to the monthly US benchmark Henry Hub price, plus a fee.

Cheniere currently produces 22.5 mtpa from the Sabine Pass plant in Louisiana, and has completed Train-1 at the port of Corpus Christi in Texas. ■

US to be third-largest LNG global exporter at the end of 2019

US LNG exports could reach 60 mtpa by the end of 2019, making the Americans the world's third-largest exporters. Both Cameron LNG in Louisiana and Freeport LNG in Texas are currently being commissioned. The first LNG production from these facilities is expected in the first half of 2019.

The developers of these projects expect all three Trains at Cameron LNG and two Trains at Freeport LNG to be placed in service in 2019.

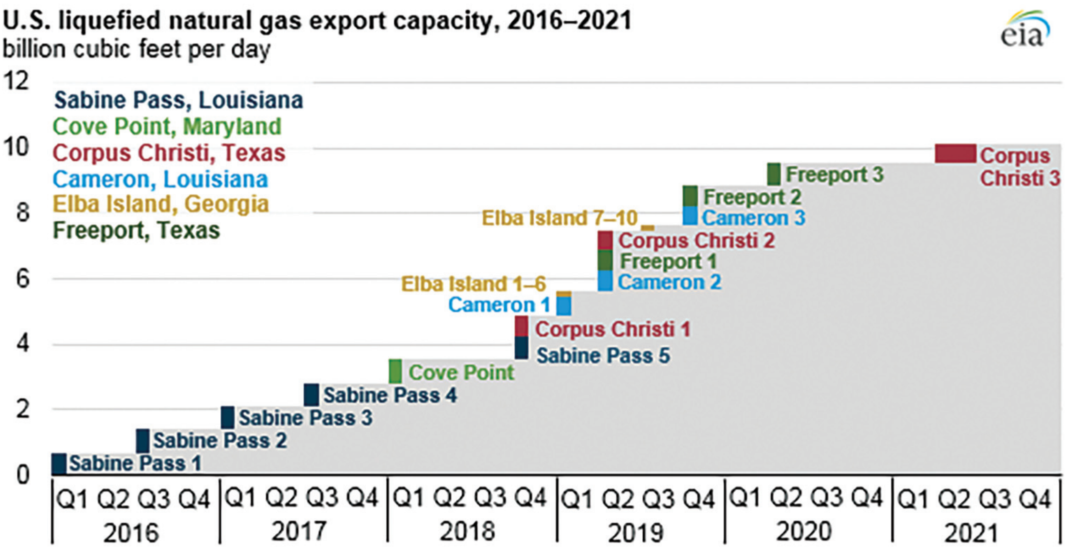
"US LNG export capacity will reach 8.9 billion cubic feet per day (Bcf/d) by the end of 2019, making it the third-largest in the world behind Australia and Qatar," forecast the U.S. Energy Information Administration (EIA). "Currently, US LNG export capacity stands at 3.6 Bcf/d, and it is expected to end the year at 4.9 Bcf/d as two new liquefaction units become operational," it added.

Actual US production at the end of 2019 will total 59.36 mtpa, comprising the partial output of new projects, including 9.96 mtpa from two completed processing Trains at Cameron LNG, 10.2 mtpa from two Trains at Freeport LNG and 9 mtpa from two Trains at Corpus Christi LNG.

These are added to existing output from Cheniere Energy's Sabine Pas plant with five Trains and 22.5 mtpa of cargoes, 5.2 mtpa from Dominion Energy's Cove Point plant in Maryland and 2.5 mtpa from the mid-scale Elba Island facility in the state of Georgia. The 0.33 Bcf/d Elba Island LNG facility near Savannah, Georgia, is also scheduled to become fully operational by the end of 2019.

EIA analysts expect the next wave of LNG exports to include four additional plants that are on the verge of taking final investment decisions. These were named as three Louisiana projects, Magnolia LNG, Delfin LNG and the Lake Charles project, as well as the Golden Pass in Texas. Added to this total will be a sixth Train at Sabine Pass.

"They are expected to make final investment decisions in the coming months. These proposed projects represent a combined additional LNG export capacity of 7.6 Bcf/d," analysts said. ■

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Dominican Republic opts for cheap energy from 450-MW Floating Power Plant

SeaFloat, a barge-mounted power plant based on SGT-800 gas turbine, will be provided by Siemens and the maritime arm of ST Engineering for Bermuda-based Seaboard Corp. The 450 MW power barge, dubbed Estrella del Mar III, will supply the Dominican Republic with electricity at a lower cost than a land-based plant staring from spring 2021.


SCC-800 SeaFloat power plant with adjacent LNG tanker

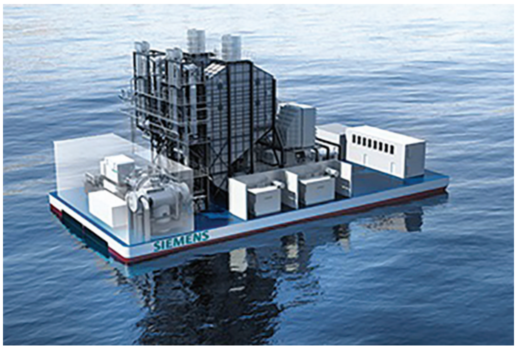
Seaboard Estrella del Mar III will be installed offshore Santo Domingo on behalf of Seaboard Corp, part of Transcontinental Capital who acts as an independent power producer (IPP) in the Dominican Republic.

Due to site constraints with limited free land, the customer selected a SCC-800 2x1 SeaFloat concept with two Siemens SGT-800 gas turbines and one SST-600 steam turbine. The turbine gensets are of single lift package design for floating applications, utilizing a frame-based design with a three-point mount. "This allows increasing the plant size in comparison to a land-based power plant," Siemens underlined.

Cheaper than land-based plant

Once operational in spring 2021, the floating power plant will provide the Dominican Republic with "a quality proven power plant at a lower cost in comparison to a similar land-based power plant," the project partners stressed.

Under a turnkey 'plug and play' concept, Siemens as team leader will provide a combined-cycle power plant with a capacity of 145 MW. ST Engineering, meanwhile, will be responsible for the engineering design, procurement and construction (EPC) of the floating power barge, the balance of plant and the installation works. The SeaFloat concept will be completed a shipyard, selected by Singapore-based ST Engineering.



Render of Estrella del Mar III.

In terms of energy storage, Fluence Energy - a JV company of Siemens and AES, will provide a 5MW/10 MWh battery. This system will be integrated in the power plant for frequency regulation control, allowing it to operate at full capacity with highest fuel efficiency.

Variations of the SeaFloat concept

Siemens SeaFloat power plants are adaptable for various needs. While most market requests are for the SGT-800 gas turbine, further solutions are available based on the based on the SGT-A65 and SGT-8000H series. Designed to be as small as possible, SeaFloat has defined a new standard in power density.

Mobility is one of the strength the floating power barge. SeaFloat power plants can be moved to any site that is accessible by sea or major rivers and require almost no investment for land acquisition. Short lead times can be achieved given that the plants are largely built from standardized equipment in leading shipyards.

Typical applications for this concept are power supply for island nations or industrial areas on shorelines or major rivers as well as brownfield sites. ■

Chevron frees up $3.6bn for fracking in the Permian

Boosting upstream investment, Chevron has set aside $3.6 billion for fracking in the Permian Basin out of a total $20 billion of capital spending in 2019. The decision comes as U.S. recoverable shale oil and gas reserves have been assessed at a record high.

The Wolfcamp shale and the Bone Spring formation in the western part of the larger Permian Basin region, hold an undiscovered but technically recoverable resource base of 46.3 billion barrels of oil, as well as 281 trillion cubic feet (Tcf) of natural gas, and 20 billion barrels of natural gas liquids, according to the latest findings in the U.S. Geological Survey (USGS).

These assessments are the highest ever made by the USGS and comes in addition to a further 20 billion bbl of oil and 16 Tcf of associated gas in the Midland Basin section of the Wolfcamp shale.

Chevron rig in the Permian Basin

Focus on high-return, short-cycle projects

Chevron, the second largest U.S. oil company, said its 2019 Capex budget of $20 billion supports a "robust portfolio of upstream and downstream investments, highlighted by our world-class Permian Basin position, [as well as] additional shale and tight development in other basins. "

"Our investments are anchored in high-return short-cycle projects, with more than two-thirds of spend projected to realize cash flow within two years," said Chairman and CEO Michael K. Wirth.

In the upstream business, approximately $10.4 billion is forecasted to sustain and grow currently producing assets, including $3.6 billion for the Permian and $1.6 billion for other shale and tight investments. Approximately $5.1 billion of the upstream program is planned for major capital projects underway, including $4.3 billion associated with the Future Growth Project at the Tengiz field in Kazakhstan.

Global exploration funding is expected to be about $1.3 billion. Remaining upstream spend will be for early stage projects supporting potential future developments. ■

ExxonMobil on acquisition spree

As the world's top oil company, ExxonMobil does not need to worry about size when it comes to snapping up assets. The Texas-based oil giant is tipped as a potential buyer of Endeavor Energy Resources, the largest privately-held oil and gas producer in the U.S. Permian basin – a takeover could cost over $10 billion.

Darren Woods, CEO of the Irving, Texas-based oil company did avoid answering questions by Bloomberg TV whether the Endeavor deal was imminent. "We have the capacity to do any size opportunity that can come about, so it's really a function of looking at the value that Exxon Mobil can extract, and how we would integrate that into our portfolio," he said but declined to specify takeover targets.

Already today, ExxonMobil surpassed its plan to mobilize about 30 rigs by year's end: the company had 38 machines drilling Permian wells as of last week, a 40% rise in six months. Snapping up Endeavor would give ExxonMobil even more exposure to the liquid-rich shale formation.

An Endeavour takeover, if realized, would be line with Exxon's actions last year to double its foothold in the Permian through the $5.6 billion acquisition of companies owned by the Bass family. Though this acquisition might come with a price tag of over $10 billion, analysts reckon ExxonMobil might well have the capability to do such a big deal, given that the oil major has more than $3 billion in cash on its balance sheet and low debt.

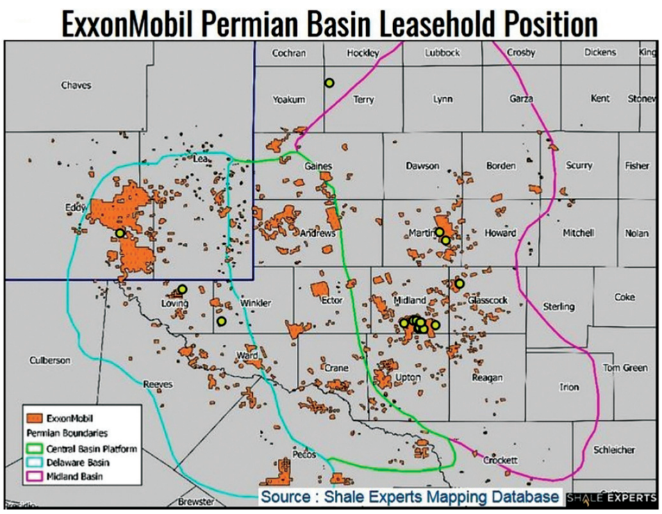
Pushing up Permian's oil output

Dubbed 'the hottest U.S. shale oil field', the Permian could nearly double crude oil production by 2023, according to IHS Markit. A rise from currently 3.2 million barrels per day to 5.4 million bbl/d would push the Permian Basin past all countries except Saudi Arabia and Russia.

Once prices recovered from a protracted slump, the Permian has been the epicenter of the resurgence in shale drilling in recent years. Leading from the front, ExxonMobil announced plans to triple its production of oil and chemical feed-stocks in the Permian Basin to 600,000 barrels of oil equivalent by 2025.

Crude oil production from the liquids-rich Permian is forecast to increase five-fold over the next few years. WTI crude oil price have bounced up 26% this year through early October before shedding nearly all of the gains in over the past eight weeks, but Mr. Woods is not rushing fracking efforts in the region.

"The price in the oil markets are going to go up and come down again, and our view is the business we build in the Permian, we're building for the long term," he said in the interview. "It needs to be efficient, low-cost and effective, so we're making sure the pace we go at allows that to happen." ■



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Upstream industry caught in a Capex conundrum

Hit by a triple-whammy of weak cash flows, meager profits and slumping stock values, CEOs in the oil and gas industry are vary about continuing to invest in increasingly risky fossil fuels. Looking for a quick return, investors want oil majors to prioritize profits over production growth. Some refocus on electricity markets.

Wall Street nowadays punishes oil and gas companies that fail to exercise "capital discipline," while rewarding companies that hand cash back to investors. "After years of subpar results, as IOCs spent more on drilling than they realized from oil and gas sales, investors are now urging oil and gas companies to quickly return cash on their investment rather than spend the money on exploration and production," said Tom Sanzillo, director of finance at the Institute for Energy Economics and Financial Analysis (IEEFA).

Still, some companies are once again finding reasons to boost capital expenditures. After three years of cutbacks and freezes, oil and gas capex will rise to $500 billion in 2018, by some estimates.

"This trend intensifies financial pressures in a cash-strapped industry," Sanzillo warned, suggesting high-capital projects such as Canada's oil sands and deep-water drilling, expose companies to severe long-term risks.

Gas investment "more sustainable"

"Prices will have to top $100 barrel, with a reliable upward trajectory, for company CEO's to take their thumbs off cost controls," he warned.

"Natural gas investments may look more financially sustainable than oil because of projected growth in global demand. But natural gas is now a low-margin business," he cautioned, so pursuing growth in gas output exemplifies the production-over-profits strategy that has sapped the sector's financial vitality.

Mayors delay Capex decisions

Cautious oil and gas majors are hesitant to make investment decisions on new upstream projects, as exploration is often a multi-decade process. Low and volatile prices make it more difficult for the industry to justify capital expenditures for drilling, pipelines, mining, and other infrastructure.

The oil majors—ExxonMobil, BP, Shell, Total, Chevron, Eni, and ConocoPhillips—vary in how they are address capital spending decisions.

At one end of the spectrum, ExxonMobil is doubling down on new oil and gas projects. "Pick a continent, and Exxon plans to drill for oil or gas there. Over the next three years, it plans to spend $25 billion a year on average, much of it on upstream development," Mr. Sanzillo said, stressing "ExxonMobil appears to have no belief in—and no plans for—a low-carbon future."

Total and BP, in contrast, have signaled a pivot toward a low-carbon future. "Their activity on this front is modest but meaningful, and bears watching," he said. Earlier this month, Total announced plans to take a $1.7 billion stake in a French electricity retailer, Direct Energie, increasing the parent company's low-carbon assets. BP executives have committed to restraining capital expenditures in 2018 while describing aggressive plans for renewable energy investments.

Upstream spending seen as "speculative"

Cash-focused investors increasingly tread the oil and gas industry as "speculative investments" and are skeptical of high levels of capital expenditures for exploration and drilling. According to IEEFA analysis the combined pressures of weakening prices, rising competition, and a negative investment outlook have diminished the status of fossil fuel investments in the stock market.

In 2008, the energy sector commanded roughly 16% of total Standard and Poor's 500 market capitalization. Today, that figure has fallen to roughly 6%. In 1980, seven of the Top 10 companies in the index were oil companies. Today, only ExxonMobil is in this league, ranking tenth. ■

U.S. oil and gas production rises, despite fewer wells

Despite the drop in rig count, the actual output of crude oil and natural gas keeps rising in the United States thanks to advances in technology and drilling techniques. Even with fewer wells U.S. natural gas gross withdrawals increased from about 78.7 billion cubic feet per day (Bcf/d) to 83.4 Bcf/d.

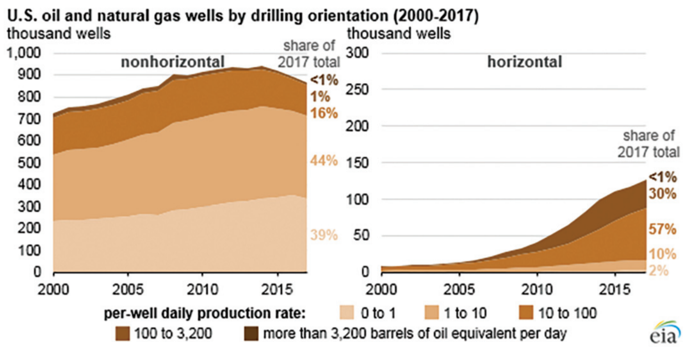
Crude oil and natural gas production continued to grow since 2017, according to data from the U.S. Energy Information Administration (EIA), most recently measured at 11.3 million b/d and 85.2 Bcf/d in August 2018, respectively. Oil output increased from 8.7 million b/d in 2014 to currently around 9.3 million b/d

In contrast, the number of wells fell from a peak of 1,039,000 wells in 2014 to currently just over 991,000.

Cutting costs is one reason why oil companies scale back their upstream activities. Horizontal wells - more expensive to drill than vertical wells - have decreased from 940,000 in 2014 to currently around 864,000.

Just 1% of vertical wells produced at least 100 barrels per day (b/d) of crude oil in 2017, but 30% of them produced at least 100 b/d. "As these relatively prolific horizontal wells became more common, production growth continued even as the well count fell," EIA analysts commented.

In EIA's report, wells are grouped into 26 production volume brackets, ranging from less than one barrel of oil equivalent per day (BOE/d) to more than 12,800 BOE/d. Most of the U.S. oil and natural gas production comes from wells producing between 50 BOE/d and 1,600 BOE/d. In 2017, wells within this range accounted for 9% of the overall count of wells but 62% of crude oil production and 63% of natural gas production. ■



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China finds new shale gas prospects, plans further exploration

Promising new shale gas prospects of a "substantial size" have been identified by China National Administration of Coal Geology (CNACG) both in Hubei and in Guizhou Province. CNACG will now develop the prospects, seeking to efficiently tap domestic unconventional reserves for the fast-growing Chinese gas market.

A large reservoir of was found at the Xianfeng Jianshan block in central Hubei Province, CNACG announced, adding it also obtained positive results from test wells in two blocks in southern Guizhou Province. Further exploration will swiftly follow suit.

In view of clean energy development, CNACG completed the first round of coalbed methane parameter evaluation in China, revealing the shale gas reserves amounted to 35 trillion cubic metres. Geothermal explorations were carried out in deep and shallow formations in Beijing, Tianjin, Hebei, Shaanxi, Qinghai and other areas in Southwest China, and shale exploration and development in Shanxi, Shaanxi, Inner Mongolia, Ningxia, Xinjiang and Guizhou.

Guizhou Province emerges as a new centre for Chinese shale gas exploratory drilling. Two further wildcatters - Hong Kong-based Honghua and Shandong-based Jereh – have started drilling test wells in the Zheng'an block.

Rampant gas demand

Unabated energy hunger is what best describes the state of the Chinese economy. In the run- up to 2023, China's gas demand is forecast to grow by 60%, and the country alone accounts for 37% of the growth in global demand, according to the International Energy Agency (IEA).

As a consequence, China's dependence on imported pipeline gas and LNG surges, along with concerns about energy security. In recent years, China had purchase half of its gas needs from abroad, and imports are expected to reach 50% by the end of the decade. Developing domestic shale gas reserve help alleviate the risk of an over-dependence on foreign energy suppliers.

Deficit from 2020 onwards

Even though the actual volume of China's shale gas production is unlikely to be a substantial new source of supply before the end of the decade, its price signal could be significant in the global market as Chinese buyers could use it in negotiations for imported gas.

LNG currently dominates China's gas imports but this will change once Russia's Power of Siberia pipeline comes onstream. The mega-pipeline alone will add 38 Bcm of gas supply, ramping up gradually by the middle of next decade.

But even this additional supply might not be sufficient. Neil Beveridge, senior analyst at Sanford C Bernstein research, noted: "Despite Russian gas, we see a growing gas deficit in the China market from 2020 onwards, with a 90 Bcm gap by 2030."

Mind spiraling upstream costs

Even if China was able to meet its production targets this year, the actual gas volumes produced would come at more than double the cost of some of the bigger US plays.

At the Fuling block of the Sichuan Basin, developed by state-owned Sinopec, the wellhead cost at $11.20 per million British thermal units (MMBtu) is far above equivalent costs in the US, where producers can extract dry gas for as low as $3.40/MMBtu.

Average well costs at Fuling were cut from CNY 100 million ($16m) in 2012 to currently below CNY 70 million ($11m). US prices are still up to 75% lower: $9.3m in the Haynesville, $6.0m in the Marcellus, $3.3m in the Barnett and $2.6m in the Fayetteville plays.

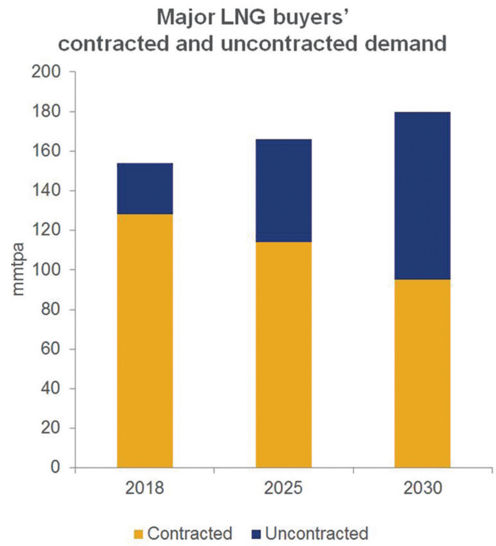
China is still in the first stage and developers have failed to bring down extraction costs in order to make drilling shale wells profitable. China's two national oil companies, (CNPC) and China Petroleum & Chemical Corp. (Sinopec), are understood to have lost over US$ 1 billion in the course of drilling early shale gas wells.

To make domestic shale gas production attractive – compared to importing pipeline gas from Russia or LNG from Australia or the U.S. – the Chinese government needs to implement reforms along the gas value chain. Liberalization is needed all the way from upstream market entry to third-party access of gas transport infrastructure and the city gate pricing mechanism. ■

> **Despite Russian gas, we see a growing gas deficit in the China market from 2020 onwards, with a 90 Bcm gap by 2030.**
>
> *– Neil Beveridge, senior analyst, Sanford C. Bernstein*

Uncontracted LNG demand seen quadruple by 2030

The worlds' seven largest LNG buyers – CNOOC, CPC, JERA, KOGAS, PetroChina, Sinopec and Tokyo Gas – together make up over half of the global market. Wood Mackenzie research reveals that uncontracted demand from these big players could quadruple to 80 mtpa by 2030.



After a number of quiet years, these Northeast Asian players have become active again in global LNG contracting activity, with over 16 mmtpa of contracts announced this year.

"As China pushes on towards a lower-emission economy, its demand for gas and LNG has grown significantly and we expect the trend to continue in the longer term," said research director, Nicholas Browne. "Other traditional major buyers, on the other hand, are facing legacy contract expiries and will be on the hunt for a mix of contracts to lower average costs and security in supply sources."

On the supply side, Wood Mackenzie predicts that 2019 could be a record year for LNG project sanctions with over 220 mmtpa of gas targeting final investment decision (FID). Some of the less prepared or competitive projects will slip into 2020 and beyond, but nonetheless a bumper year beckons.

Frontrunners to get the green light include the US$27 billion Arctic LNG-2 in Russia, at least one project in Mozambique and three in the US. Nearer to Asia, expansion and backfill projects in Australia and Papua New Guinea will also be in the running.

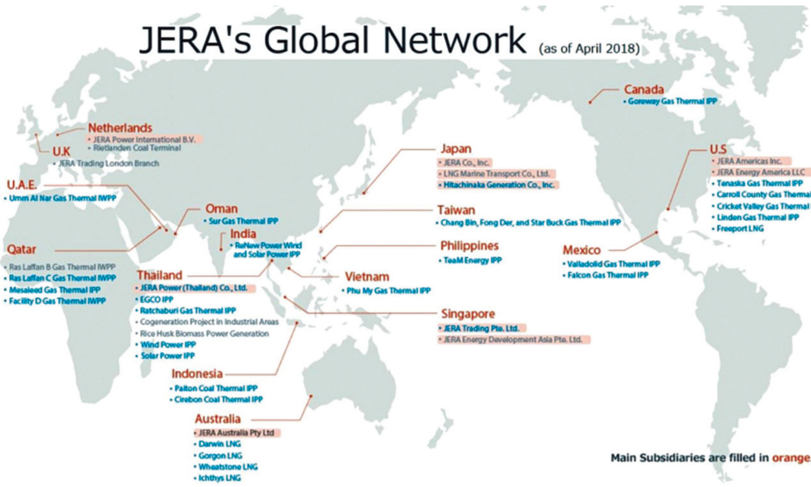
However, LNG suppliers will need to ensure they can meet the changing needs of major LNG buyers as they seek a variety of contracts to meet their different needs. In addition to price, factors such as contract flexibility, index, source diversification, upstream participation and seasonality will all be considerations.

"Market liberalisation and uncertainty on longer-term demand in more mature markets, such as Japan, South Korea and T~aiwan, will mean more room for spot and short-term purchases," Browne said, suggesting: "While oil indexation will continue to dominate markets due to familiarity and ability to hedge, Asian buyers should be more inclined towards hub indexation to boost diversity and enable sales into Europe. "

Looking forward, he expects 2019 will be the biggest year ever, in terms of LNG capacity sanctioned, for liquefaction project FIDs. Asia's major buyers are likely to be at the forefront in ensuring this next generation of LNG supply is brought to market. ■

JERA to become Japan's largest utility from April 2019

Japan's largest LNG importer JERA will also become the nation's biggest power producer as of April 2019 when it will take control of TECPO and Chubu Electric's domestic power business. Rated 'A-minus by Standard & Poor's, analysts caution that over the next three years JERA plans to invest in high-risk upstream LNG concessions and unregulated power projects overseas.



Rated 'A-minus by Standard & Poor's, the agency expects JERA's debt profile to remain steady as it incorporates TEPCO's and Chubu's power generation business, largely due to longterm power purchase agreements (PPAs).

"We regard TEPCO Holdings, Chubu and JERA as a virtual group, and we view JERA as somewhat insulated from the group," S&P analysts cautioned, anticipating that "certain key financial metrics for JERA are likely to stay slightly weak relative to our rating because JERA will step up investments in power generation facilities and expand its overseas business."

Stable cash flow, debt-to-income ratio

Still, the stable outlook reflects S&P's view that the Japanese LNG and power generation giant will generate a stable operating cash flow. The agency estimates JERA's outstanding debt as of the end of fiscal 2018 will roughly equal its total cash and deposits.

"Upon assuming its parents' domestic thermal power generation businesses in fiscal 2019, its operating cash flow is likely to benefit from highly transparent pricing mechanisms and long-term contracts to sell power to its parents," the report reads.

S&P said it might consider downgrading JERA if there would be a substantial delay in a takeover of its parents' domestic thermal power generation businesses. "Conversely, an upgrade is unlikely for now, in our view. This is because consolidation of the domestic thermal power generation businesses it succeeds from its parents will take time," analysts said.

Looking ahead, JERA plans to invest in upstream LNG concessions over the next two to three years which analysts think will "attract high business risk, and gradually expand overseas power generation – an unregulated, riskier business." ■