LNG North America

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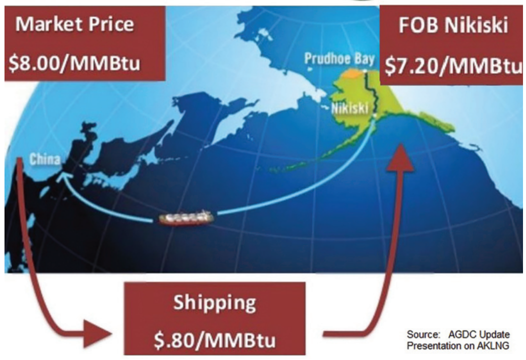
Alaska LNG hinges on Chinese funding, FID planned in 2019

Regardless of the trade war between the United States and China, state-controlled Sinopec has reaffirmed plans to reserve 75% of the project's LNG production capacity. Sinopec wants to become the project's main offtake customer, allowing CIC Capital to be an equity investor, while the Bank of China will help refine the financing structure. Financial close is targeted for late 2019, or in early 2020.



Chinese funding will be instrumental to get the huge Alaska LNG venture off the ground. The Bank of China and CIC Capital, part of China Investment Corp, are firmly standing behind Sinopec's aim to conclude definite offake agreements for LNG shipments from Alaska.

Costs of realizing the 20 mpta Alaska LNG project are estimated to come in at $43.4 billion, and the project developer Alaska Gasline Development Corp. (AGDC) is open to almost any form of foreign financing, combined with firm offtake accords.

Sinopec in early October signed a supplemental agreement with Alaska Gasline Development Corporation (AGDC) to reserve 75% of the LNG production capacity in the 20 mtpa Alaska LNG venture. To sell the remaining 5 mpta, not booked by China, Alaska LNG developers are in negotiations with Tokyo Gas, Korea Gas and PetroVietnam, but other Chinese buyers may also snap up some volumes.

AGDC President Keith Meyer said the latest agreement with Sinopec "reaffirms the willingness to establish LNG trade between Alaska and China for the mutual benefit of all parties."

The second offtake accord with Sinopec came shortly after AGDC arranged feed-gas deals from the prolific North slope resources in Alaska. ExxonMobil signed a preliminary accord to sell its 13.8 Tcf of natural gas resources in the Prudhoe Bay and Point Thomson fields, and BP is also looking to divest some of its North Slope resources. The two agreements with Exxon and BB committed 22.7 Tcf of natural gas to the Alaska LNG venture, with the supply sourced mostly from the 32 Tcf of easily recoverable feed-gas resource on the North Slope.

Tit-for-Tat Tariffs

Geopolitically speaking, the new agreement comes at a sub-optimal time given that the U.S. President Trump is the driving force behind an escalating trade war with China.

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Shell is "not going soft" on oil and gas, warns of LNG "supply crunch"

Royal Dutch Shell will keep investing in global gas projects as demand is anticipated to grow at a rate of 2% per year, twice the rate to worldwide energy demand. "Our core business is, and will be for the foreseeable future, very much in oil and gas… and particularly in natural gas," Shell CEO Ben van Beurden told a conference in London, warning about the risks of an LNG "supply crunch" by the mid-2020s.

Although Shell has invested more than other Big Oil companies in clean energy, spending around $2 billion/year, van Beuden said Shell is "not going soft" on hydrocarbons. Demand for natural gas, in particular, is expected to increase as the cleaner-burning fossil fuel will play a major role for decades to come as part of the shift to low-carbon economies.

"It's always hard to really see where the demand curve is," he said, suggesting that investment of Big Oil and especially the Qatari LNG expansion plans would be not enough to close the gap.

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Harbour view of Kitimat's industrial zone where LNG Canada is being built

AGENDA

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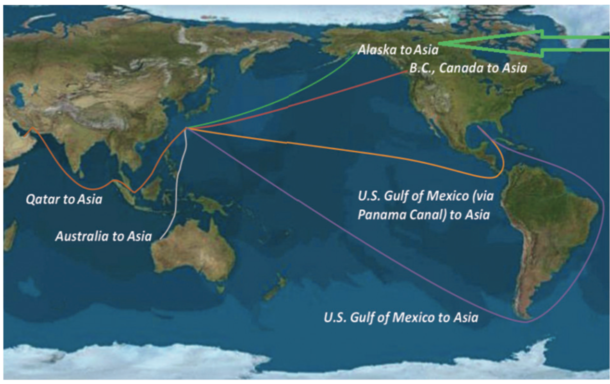
In September, the Trump administration enacted a 10% tariff on $200 billion worth of Chinese products that is scheduled to rise to 25% after January 1.

Beijing hit back with tariffs of 5-10% on more than 5,000 products imported from the United States, including LNG at 10%. Both sides have vowed to enact additional tariffs if the other side retaliates.




Render of Alaska LNG project

Analysts cautioned that Sino-U.S. trade tensions could be exacerbated by a the new United States-Mexico-Canada Agreement (USMCA), and it is also unclear whether Shell's move to take FID on the 14 mtpa LNG Canada project could undermine progress on the LNG Alaska venture.

FID planned for late 2019

Seeking to disperse concerns, an AGDC spokesman said FID on LNG Canada "does not affect" plans to issue an FID in late 2019 or early 2020, which would put Alaska LNG on track to export its first cargoes in 2025.

On the contrary, the financial close on LNG Canada showcases the attractiveness of exporting LNG from the Pacific Coast of North America, with shorter sea voyages for shipping cargoes to Asian markets.

Traders and portfolio players in the global gas market have already accounted for the volume of gas LNG Canada will export. "This supply is already factored into the conversations AGDC is having with potential customers," the spokesman said, suggesting: "Demand for LNG in Asia is greater than both of these projects' combined capacities, so there's still plenty of room for Alaska LNG's 20 mtpa."

Shell estimated LNG Canada cargoes would take about 10 days to reach Asian ports, while cargoes from the U.S. Gulf Coast can take 24 days to reach Asian ports, as they have to traverse the Panama Canal.

Costs for Alaska LNG amount to $45 million

To realize ambitious plans for exporting LNG from Alaska, project partners need to build an 800-mile gas pipeline from the North Slope in northern Alaska to a planned liquefaction plant in Nikiski on the Kenai Peninsula, south of Anchorage. Total cost of this project is estimated to come in at up to $45 billion.

State-owned AGDC estimated the wellhead price the state of Alaska itself would receive for its royalty share of gas would likely range between $1.00/MMBtu and $2/MMBtu.

A federal record of decision, which would clear the way for the FERC approval, is expected in February 2020. That would allow for a final investment decision in 202020. Construction would then be underway in 2021 and completion and commercial operations could be expected by 2025. ■

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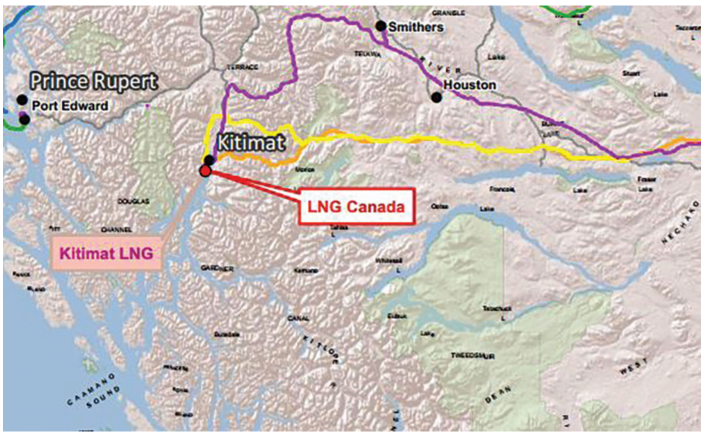
Qatar, the world's largest LNG exporter, is advancing plans to boost its output by 30% by adding a fourth train at Qatar Petroleum's LNG export plant. Still, the Shell CEO is convinced this is not enough and new FIDs on natural gas liquefaction and export projects are needed to avoid supply shortages.

"Compelling low cost"

Shell has spent more time on Canada LNG than other projects in terms of de-risking it, van Beuden said, adding: "Let me be quite clear, LNG Canada would not have made it if it had not had such a compelling case on costs. So it should be. Even at a time of $70, or $80 or even $90 per barrel oil."

Financial investment decision (FID) on Canada LNG was announced on October 1, and the $40 billion project has now immediately moved into construction phase. Once completed, joint venture partners will be exporting LNG from two trains totaling 14 million tons per annum (mtpa).

Van Beuden expressed confidence that the project will be competitive on a capital spending and production cost basis. Modular construction, standardization of industry equipment and the fact that the liquefaction terminal is being built on a brownfield site will ensure that total cost will stay at a "competitive" $1,000 per mt/year, he said.



Right project, place and time

Anticipating global LNG demand to double from today's levels by 2035, the Shell CEO specified "much of this growth is coming from Asia where gas displaces coal." Hence, supplying LNG to wider Asia will be critical as the world transitions to a lower carbon energy system.

"We believe LNG Canada is the right project, in the right place, at the right time," he concluded, saluting Shell and its four partners, Mitsubishi, Petronas, PetroChina and Korea to start building the plant. Cost for the immediate construction will be up to C$40 billion (US$31Bln) for the liquefaction plant and associated facilities, with completion scheduled before 2025. ■

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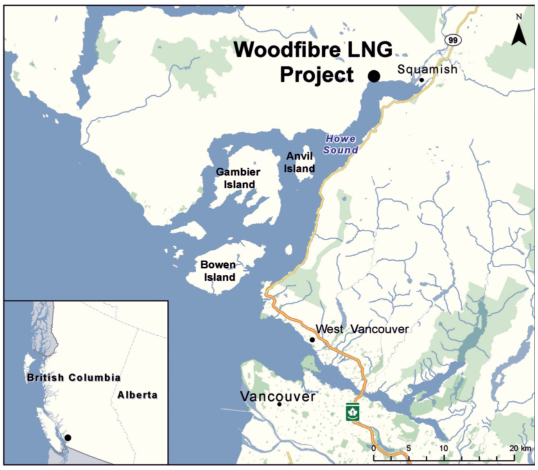
Woodfibre LNG to start construction in Q1-2019

David Keane, President of Canada's Woodfibre LNG project, has announced the imminent construction start for the brownfield liquefaction facility, licensed to export over 2 mtpa of LNG for 40 years. The decision to the construction stage comes shortly after the Sinapore-backed project signed a preliminary supply deal with the largest Chinese LNG importer, China National Offshore Oil Corp (CNOOC). Works are slated to start in the first quarter of 2019.



"We're hoping to move to a notice to proceed to construction in the first quarter of 2019," said Keane. "It will be sometime in February or March," he said. The Woodfibre President has been in his post since August 2018, and was previously head of the lobby group BC LNG Alliance and prior to that with BG Group.

Woodfibre LNG, the Canadian export venture planned for the district of Squamish, BC, is backed by Indonesian businessman Sukanto Tanoto and his Singapore-based Pacific Oil & Gas Ltd, part of the Royal Golden Eagle (RGE) Group.

Project developers said they had signed a Heads of Agreement with CNOOC Gas and Power Trading & Marketing for 750,000 tonnes per annum of LNG. The supply accord with CNOOC, an importer of LNG to China since 2006 and with a network of nine terminals, would take effect in 2023 and last for 13 years.

Set to be built on the site of a former pulp mill at Squamish, north of Vancouver, the relatively small-scale project is expected to start operating in about four years' time. Woodfibre LNG is the only liquefaction plant venture with full permit approvals in the Canadian Pacific Coast province of BC.

KBR Inc. has been chosen for preliminary engineering activities, following the completion of a competitive front-end engineering and design tender process. The services include additional FEED work and cost optimization as well as a proposal for an engineering, procurement and construction (EPC) contract.

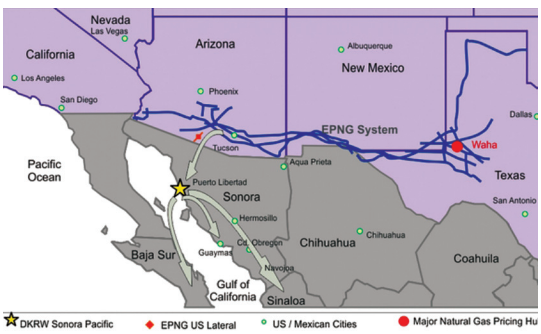
Environmental approval has been granted by the Canadian federal government in Ottawa, and Woodfibre LNG is also cooperating with a local First Nation tribe, right down to letting it choose some of the technology for the plant. The Squamish First Nation Chiefs and the tribal council were able to select air cooling as the technique the Woodfibre plant will use to cool its natural gas in the LNG production process. ■

US exports to Mexico rise after MPL gets Sonora LNG approved

More shale gas produced in Texas will soon cross the border to Mexico after the U.S. Department of Energy (DOE) approved an application by Mexico Pacific Ltd (MPL) to export up to 1.7 Bcf/d to a planned liquefaction and export plant in the state of Sonora. MLP is developing a an LNG export facility of up to 12 mtpa in the Mexican state of Sonora, with the first phase planned to be in service in 2023.

In DOE's September ruling, MPL was granted permission for 20-years to export the additional gas volumes via existing cross-border interconnectors, such as Kinder Morgan's Sierrita Gas Pipeline. Most of the gas supply will be sourced from the Permian and San Juan basin, MLP said, as well as from the Texas-based Eagle Ford Shale and Barnet Shale.

In addition to the US gas supplies, MLP is also working on securing a deal to purchase up to 400,00 MMBtu/d from Mexico's CFEnergia, part of the Comision Federal de Electricidad. The company's international arm hold a blanket authorization to import up to 2,920 Bcf of U.S. pipeline gas and controls the first 700 MMcf/d of transport capacity on the Sonora Pipeline.



In Sonora state, MPL is developing a 12 million metric ton per year (mmtpa) LNG export facility next to IEnova pipeline that is said to benefit from "multiple supply routes, allowing both Henry Hub and Waha gas to be efficiently supplied to the site. The LNG project will be built in stages, consisting of various 1 mtpa units. Phase-1 is envisaged to have a capacity between 2 and 4 mpta.

Construction is slated to start in 2020 with a view to placing the facility in service in 2023.

Once operational, the Sonora LNG facility will allow shipments to remote locations within Mexico serving power generation plants that are not linked to the country's gas pipeline grid. Alternatively the LNG could be re-exported to countries having a Free Trade Agreement (FTA) with the United States. Approval for export to non-FTA countries is still pending.

MLP claims it can offer up to 35% lower shipping cost to Asia compared with rival LNG export projects on the U.S. Gulf Coast from where shipments need to transit the Panama Canal on the shortest route to Japan, Korea and China. ■

Second wave of U.S. LNG projects gather pace

Tightening in global LNG markets has allowed the second wave of US LNG ventures to gain momentum again. Since early 2018, a second wave of projects set to bring more than 10 mtpa to the market under binding sales and purchase agreements (SPAs) have reached the starting blocks.

"The increase is in SPAs is remarkable. In the period since the first wave of US LNG projects and late 2017, just 2 mmpta had been locked in," said Wood Mackenzie director, America gas research, Kristy Kramer.

At the end of August, the US Federal Energy Regulation Commission (FERC) announced regulatory timelines for 12 LNG projects. This means that as well as the six developments that are through the regulatory process, 11 more are expected to receive their final order from FERC by mid-to-late 2019.

Amid strengthening fundamentals, Wood Mackenzie believes the global LNG supply-demand gap in 2025 will expand from 45 mmpta to 65 mmpta. This will increase the pressure on US LNG projects to finalize commercial arrangements as they look to take FID in the next 12-18 months.

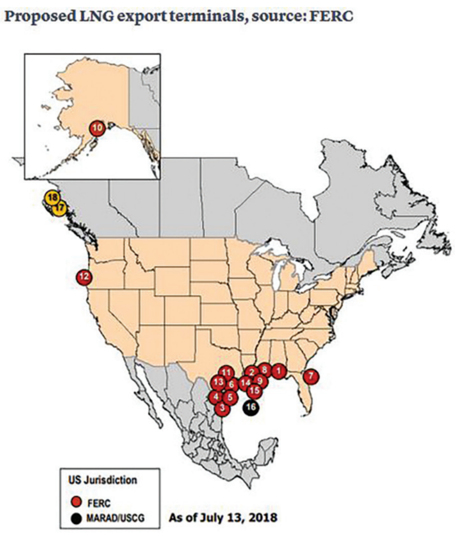
"Gas supply will rise in importance for the next wave of US LNG. The American market will increase by more than 30 billion cubic feet per day (cfd) between 2012, when the first US project took FID, and 2022 when those projects will be online," Ms Kramer said.

In 2022, about 36% of US gas will be consumed in or exported through the West South Central census region, which includes Texas and Louisiana. This concentration of demand is likely to stir competition for pipeline capacity to reach new LNG projects, hence gas supply constraints will emerge as a focus area, ad critical enabler for the next wave of US LNG.

"Buyers will need to have comfort in the strategy for getting gas into liquefaction, and lenders will want to be confident in a project's overall commercial offering," Ms Kramer said.

Moreover, US producers may also be interested in getting into the mix. "Notably absent from the first wave, US producers have witnessed LNG exports rise to current levels of over 3 billion cfd," she said, suggesting: "They are expected to approach 10 billion cfd in 2020."

Producer involvement would likely change the commercial structures and risk-sharing mechanics of future US LNG projects. Wood Mackenzie said it is hearing interest from US producers, LNG buyers, and project developers, but still awaits a 'big announcement'. ■



Map of FERC-approved US LNG terminals

Peak oil forecast for 2023, followed by a peak in gas demand by 2034

Anticipating a speedy energy transition globally, the global classification society DVN GV says upstream players are adapting to this trend by shifting to faster, leaner and cleaner hydrocarbon production techniques. Oil and gas demand is forecast to peak in 2023 and 2034, respectively, prompting upstream players to favour a greater number of smaller reservoirs with shorter life-spans.

Going forward, operators will favour production from a greater number of smaller reservoirs with shorter life-spans, lower break-even costs and reduced social impact compared to those currently in operation.

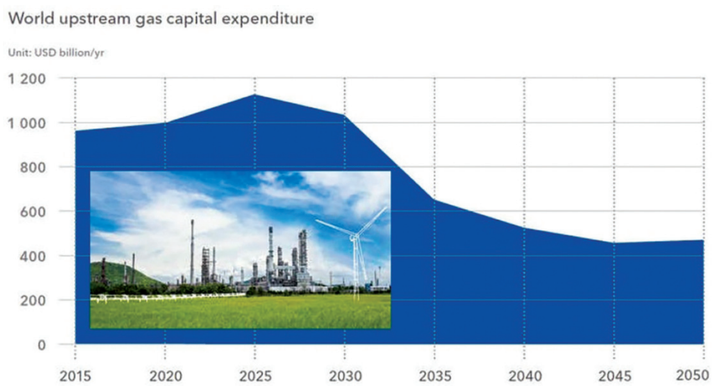
"Most easy-to-produce, 'elephant' oil and gas fields have been found and are already in production. Smaller reservoirs will likely be harder to explore and develop commercially, said Liv Hovem, CEO, DNV GL – Oil & Gas.

Digital enabled technologies such as directional drilling and steerable drill bits, 4D seismic backed by data analytics and steam flooding, will hence be crucial to ensure that exploration and production is economic and efficient. Future-proof production methods need to adapt to smaller fields with a bigger variety of technical challenges.

Anticipating the world energy mix in the lead-up to 2050, DNV GL predicts peak oil in 2013 – although new oil fields will be needed until at least the 2040. Demand for natural gas, widely seen as the cleanest-burning fossil fuel, is expected to reach a peak before 2035.

Decarbonization, e.g. through carbon capture and storage (CCS), should be widely adopted by the upstream industry, DNV GL says. According to the Outlook, Global warming will likely reach 2.6 degrees Celsius (°C) above pre-industrial levels in 2050.This is well above the 2°C target set out by the COP 21 Paris Agreement on climate change.

By 2050, a staggering 972 gigatonnes of carbon are forecast will be emitted, overshooting the 810 gigatonne budget associated with the target. Hence, Mr. Hovem reminded the upstream industry of its "vital role" in the energy transition, urging the sector to "maintain a sharp focus on decarbonization, sustainable production, cost management, and the need to embrace innovative technologies." ■



China's coal-to-gas switch boosts LNG demand

Coal-to-gas switch policies in China's energy sector are expected to boost the country's LNG demand by a 12 million tons in 2018, exceeding last year's record growth of 8 mt. Already today, China's energy hunger lies behind half of global LNG demand growth and Wood Mackenzie says: "Given China is only through its five year clean air policy, this growth story is far from finished."

But while China grabs all the headlines, LNG demand growth is a reality throughout Asia. In total, Asia-Pacific LNG demand is set to grow a further 60% to reach 337 million tons per annum (mmtpa) by 2030 – while the rest of the global market is only 75 mmtpa currently.

Responding to these strong demand signals, suppliers are now re-positioning for growth. The FID of LNG Canada a fortnight ago was the first major greenfield project to move ahead since 2015, and Wood Mackenzie says "2019 will be the largest year for LNG FIDs ever" with projects in Russia, Qatar, Mozambique and the U.S. expected to sanction. "In the medium-term, LNG producers in Southeast Asia, Australia and PNG will also be aiming to capture some of this growth through expansion and backfill of existing facilities," added Nicholas Browne, Gas and LNG research director.

Upstream: More large-scale fields get sanctioned

Investments in new upstream project have been scaled up globally in 2018, both oil and gas, and this trend has filtered through to Asia-Pacific as well. Though the number of fields sanctioned stayed roughly the same, the key change is the size of fields getting the green light. The average project to hit FID in 2018 is over twice the size of those in 2017, up from around 375 million boe last year to around 850 million boe this year.

"Asia-Pacific matches the trend exactly, with a jump to an average of 287 million boe versus 143 million boe in 2017. Key sanctions include SK320 and SK408 in Malaysia, Reliance's KG D6 satellite cluster in deepwater India, and CNOOC's first operated deepwater gas project in China, Lingshui. Together these projects will require nearly US$8 billion of investment, "said Angus Rodger, upstream research director.

China's NOCs raise budgets, look oversees

Looking at the Lingshui sanction, analysts see the strategy of Chinese NOCs becoming "more dynamic" to match rising domestic gas and LNG demand. Senior analyst Maxim Petrov sees China's national energy champions starting to become more active.

"CNOOC and PetroChina are raising their domestic budgets and returning to the international stage. Investment at home is increasingly shifting to gas, driven by its strategic national importance and lower carbon intensity. The NOCs will aim to capitalise on China's growing gas demand, with shale gas, LNG storage and pipeline infrastructure gaining prominence," he said.

But there is also a clear move towards high-impact exploration overseas and bilateral deal-making. "Expect the Chinese NOCs to continue focusing on large conventional oil fields in the Middle East and Latin America, but also target integrated gas opportunities in Russia, Qatar and Asia-Pacific," Petrov said, forecasting that government-to-government relations and partnerships with the Oil Majors will be crucial in securing future growth opportunities.

M&A activity keeps rising in Asia

Throughout Asia, there has been a surge in mergers and acquisitions, with over US$6.8 billion worth of upstream assets changing hands in 2018. Australia accounts for much of this uptick, with Santos's US$2.2 billion acquisition of Quadrant Energy, the pick of the deals down under. "Deal activity in Australia has been led by local players looking to reshape their portfolios to focus on domestic gas demand and future LNG backfill options. But Wood Mackenzie expects to see further liquidity down under, as north Asian buyers seek to secure resources and private equity funds search for overlooked opportunities

NOCs in the region, burdened by maturing assets and growing domestic energy demand, are looking for partners with technical and financial capacity to help maximise recovery will grow. Petronas, Pertamina and PetroVietnam are all likely to be on the lookout for new partnerships in 2019, to support continued investment in both old and new field developments.

More recently, OMV's $800 million entry into Malaysia suggests that the corporate landscape in Southeast Asia could also be set for an injection of fresh capital and ideas.

"The uptick in activity in Southeast Asia has been slower, but we are seeing the first signs of new entrants showing interest again, to fill the gap left by some of the larger IOCs that have exited or de-emphasised the region. Look out for more deals in Malaysia and Indonesia, particularly after Indonesia's general election in April 2019," said upstream research director Andrew Harwood.

"Although things are looking rosy in the region, it is worth noting that for some parts of Asia, the recovery may still lag other regions as politics and national objectives increasingly override commercial considerations," he cautioned. ■

Brazil: Golar on the lookout for new investments

Golar LNG chairman Tor Olav Troim said he is looking for the next opportunity, encouraged by investors embracing the $1.74 billion integrated LNG-to-power project in Brazil. Golar Power, a venture between Golar LNG and Stonepeak Infrastructure Partners, in April took FID on the 1.5GW project in northeast Brazil.

The project company CELSE will receive $1.340 billion of non-recourse financing that will be used to fund the remaining Capex of the $1.74 billion project. Start-up is scheduled for January 2020.

CELSE said it will use the total proceeds from the financing to fund the remaining capital expenditures for the 1.5GW combined-cycle power plant, a dedicated 500KV high-voltage transmission line spanning over a distance of 34 kilometres, an associated gas pipeline and mooring infrastructure required for the integrated LNG import terminal.

The total equity contribution of approximately US$400 million has been fully paid-in, including US$123 million in cash reserve accounts that were pre-funded by the project sponsors. Golar and Stonepack said in a statement they expect the CCGT will generate an annual EBITDA of US$323 million at current exchange rates, prior to any dispatch.

Payments under the executed Power Purchase Agreement (PPA) are inflation indexed, hence they allow the plant operators to pass-through of fuel costs to PPA counterparties. Start of full commercial operations is scheduled for January 1, 2020.

Golar Power CEO Eduardo Antonello commented the financing structure was establishing a "precedent for financing in local currency" in support of projects receiving inflation-adjusted revenues in local currency.

"The project bond issuance has attracted the interest of multiple international investors and opens a new horizon of opportunities for infrastructure development. With this experience, we believe Golar Power is uniquely positioned to help deliver these opportunities globally to new and underserved customers and geographies," he said.

Together with the financial close for the LNG-to-power project, Golar has also signed agreements with ELSE to charter the Golar Nanook, a fully customized 170,000 cubic metres FSRU, for 26 years.

AES forges ahead with LNG-to-power project in Panama

AES Colón – a $1.15 billion LNG import terminal and adjacent combined-cycle power plant – is being fast-tracked in Panama. The project comprises the first LNG regas terminal in Central America and a CCGT with 381 MW capacity. Commercial operation was slated to start on September 1.

The integrated LNG import and power generation project helps reduce the dependency of Central American countries on oil-fired generation. Fuel oil, a comparatively expensive energy source, is increasingly replaced by cleaner-burning natural gas.

Built at the entrance of the Panama Canal, the AES Colón project includes a CCGT, driven by 6F.03 gas turbines, with a 10-year power purchase agreement, and a 180,000 cbm LNG storage tank and regasification facility, to supply gas to the plant.

The CCGT at the AES Colón regas and power generation venture was build in just 27 months, and during construction, the project created more than 2500 jobs. Once fully up and running, about 200 jobs will be needed to support the plant's continuous operation.

"The inauguration of AES Colón is a significant step toward diversifying the energy mix in Central America and the Caribbean, introducing cleaner alternatives in Panama and beyond," commented AES President Andrés Gluski. "We expect that the entry of low-cost US LNG will transform the Central American energy sector, much as it has in the Dominican Republic. This facility is the latest example of how innovation is driving a cleaner energy future on a global scale."

AES Corporation is a Fortune 500 company that generates and distributes electrical power. Headquartered in Arlington, Virginia, AES is also exposed to global LNG markets through integrated regasification and power generation such as the one in Colón, Panama.

Venturing into energy storage, AES and Siemens in January 2018 formed a joint venture focusing on lithium-ion powered energy storage. So far, biggest project in Fluence's portfolio is a 100–400 MWh "power center energy storage project" for Southern California Edison at Los Alamitos, California. Other major projects comprise a 40 MW storage facility on behalf of San Diego Gas & Electric, and install six storage projects across Germany that will provide grid stabilization.

Render of AES Colon's integrated LNG-to-Power project in Panama

Safety and Security in LNG:
Integrated Systems Improve Performance and Reduce Costs

The LNG industry has an excellent safety record. Despite this, the LNG industry is constantly challenged to implement higher levels of safety and security requirements to accommodate increased public sensitivities and government regulations.

Successful LNG projects are defined by their ability to achieve capital efficiency. Experience has shown that CAPEX reductions can be realized through modular construction methods of the LNG plant, which involve the construction of the plant in transportable modules at factories around the globe.

Need for a Holistic Solution

Operators of LNG facilities increasingly want to simplify and standardize, allowing them to reduce the complexity of their systems.

As a leading global automation supplier, Honeywell offers an all-in-one solution that helps make new LNG facilities efficient and productive from day one. The company's integrated control and safety system (ICSS) helps LNG firms maximize their operations with accurate and on-time information, precise measuring technologies, safety and security.

With Honeywell's comprehensive offering, multiple gas detectors, infrared fire detectors, closed circuit cameras, command and control systems, stringent physical and cyber security measures, and personnel safety training are all part of a holistic solution for safe operations.

Honeywell's Connected Approach

Honeywell's connected approach to plant safety helps the LNG industry improve its business performance and peace of mind. It includes independent yet interrelated layers of protection to deter, prevent, detect and mitigate potential physical and cyber threats to both land- and sea-based operations.

At the heart of Honeywell's approach to safety and security is its latest safety instrumented system (SIS) offering, Safety Manager SC, which integrates process safety data, applications, diagnostics and critical control strategies, and executes safety integrity level (SIL)-defined safety applications in a fully redundant system.

Safety Manager SC is a cost-effective solution for a distributed safety architecture throughout LNG facilities. The system employs a modular construction strategy allowing users to locate remote I/O cabinets in Zone 2/Div. 2 process areas, and in operating environments with temperatures from -40 to 70 degrees C. This results in lower capital costs by enabling cabinets and other equipment to be built and assembled in the closest geographical location.

As a SIL3-certified system, Safety Manager SC provides high availability to keep LNG processes running and avoid unplanned downtime. The system also enables users to comply with the latest global safety and cyber security standards while ensuring maximum reliability for their operations. Safety Manager SC is ISASecure certified for cyber security

Safety Manager SC

Honeywell's Enraf Tank Gauge for Custody Transfer and Inventory Control

By utilizing Honeywell's current Series C controller design, Safety Manager SC supports a more compact design and flexible, simplified architecture. The system has a reduced number of core components, which are easy to troubleshoot and maintain.

At the same time, Honeywell's Universal I/O technology and LEAP™ project methodology represent a new paradigm for automation and safety projects, allowing for easy late changes, minimizing risk, reducing the number of required spare modules, and streamlining future additions to the ICSS.

Finally, LNG operators can seamlessly pair Safety Manager SC with the best-in-class Experion® PKS control system to optimize the safety and performance of any size facility. This approach reduces the number of databases and engineering tools, integrates alarms and events, automates tracking and validation of safety systems and final elements, and provides secure integration with subsystems such as fire & gas, security, etc.

Conclusion

By implementing the advanced Safety Manager SC solution, LNG operators can reduce their CAPEX requirements, and at the same time, deploy a distributed SIL3 safety architecture that is reliable, flexible and easy to maintain.

For more information, please visit www.hwll.co/SafetyManagerSC

One Platform For All Your Process Safety Needs

Safety Manager SC – Simplifying Plant Safety

Discover the advantages of standardizing on a single safety platform. Safety Manager SC not only meets your specific size, availability, and cost requirements, but is scalable and flexible as well. It is a TUV SIL 3 certified "out of the box" solution, that reduces system complexity, streamlines engineering, and lowers support costs.

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‘Producer economies’ need to diversify, hedge against price volatility

The International Energy Agency (IEA) has called on Saudi Arabia, Russia, Iraq, the UEA, Nigeria and Venezuela to step up efforts to diversify their economies to be able to cope with volatility of shale gas supply, and uncertainties over the pace of demand growth. In its Outlook for Producer Economies, the IEA assesses how the world’s six resource-dependent economies might fare until 2040 under a variety of price and policy scenarios.

The volatility of hydrocarbon revenues, due to the rollercoaster in oil prices over the past 10 years, presents dilemmas for countries whose budgets depend on them, especially if their economies and finances are not resilient. Since 2014, the net income available from oil and gas has fallen by between 40% (in the case of Iraq) and 70% (in the case of Venezuela), with wide-ranging consequences for economic performance.

High oil prices slow down reforms

The rebound in oil prices to comparative highs are “a double-edged sword,” according to the IEA. Higher revenues provide the means to reform, but they can also appear to reduce its urgency. Higher energy prices, meanwhile, encourage production elsewhere while accelerating structural changes in demand, which affect the producers’ long-term markets.

In the face of higher energy prices, the UEA managed to cut its LNG import requirement over the past year by fast-tracking deployment of solar energy. “The gas price was around $1.10 per million British thermal units for some 15 years, but is now close to $3.00 per MMBtu,” the IEA noted.

Considering that many producing nations face strong pressure from youth unemployment, the Dr Fatih Birol, the IEA’s executive director says “fundamental changes to the development model of resource-rich countries look unavoidable.” More than 50% of the population living across the Middle East is under the age of 30; the proportion is more than 70% in Nigeria.” In many major producers, income from oil and gas will not be large enough to provide for these growing populations, even in scenarios where oil demand continues to grow to 2040 and prices remain relatively robust.

The rollercoaster in oil prices over the last decade has exposed the structural weaknesses in many of the major exporters

Different dilemmas in Russia compared with GCC

Looking at Russia, Qatar and Turkmenistan, revenue from LNG and pipeline gas “can provide a useful hedge against changes elsewhere” in the energy mix. “These producers face a range of dilemmas arising from a rapidly changing global gas market, but overall gas consumption is higher in 2040 than today in each scenario that we examine, including the sustainable development Scenario,” stated the IEA.

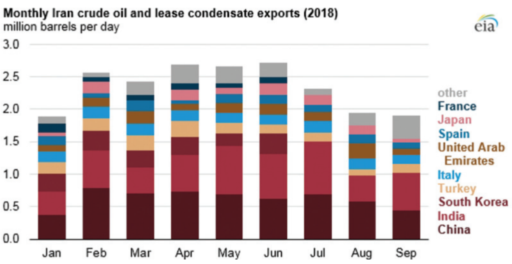
In contrast, domestic gas production is barely keeping up with demand growth in many nations in the Gulf Cooperation Council. In the GCC, gas consumption has been fueled in the past by associated gas, available essentially at zero cost as a by-product of oil production.

A surge in gas use and limited availability of associated gas now require that gas be sought and produced as a commodity in its own right, and often imported. Across the GCC; gas demand has risen two-and-a-half times since 2000, with around half of this growth coming from power generation. ■

Iran produces less oil and gas since U.S. threatened sanctions

Since the Trump administration threatened fresh sanctions against Iran, the oil-rich country has substantially scaled down its production and exports of crude oil and natural gas. In May 2018, the White House said it would withdraw from the Joint Comprehensive Plan of Action (JCPOA) and reinstate sanctions against the regime in Teheran.

In September, Iran’s crude oil and condensate exports fell to 1.9 million b/d – after reaching a peak at about 2.7 million barrels per day (b/d) in June. Although some countries, such as France and South Korea, stopped importing crude oil and condensate from Iran in July, other countries continue to import from Iran, according to Clipper Data.



The United States has not imported crude oil and condensate from Iran in several decades.

The laughing third

Imposing sanctions may not help resolve issues in Iran, as the regime has just turned around and supplied its oil and gas production to energy-hungry nations in Asia, notably China and India. ClipperData indicates that the two countries collectively received nearly half of Iran's crude oil and condensate exports in the first half of 2018.

China's imports from Iran averaged 644,000 b/d and India's imports from Iran averaged 554,000 b/d during this period. In September, China's imports from Iran fell to 441,000 b/d, the second lowest level since December 2015, while India's imports from Iran were 576,000 b/d.

Adamantly opposing Trump’s hard stance against Iran, the European Union passed a statute to protect EU-based companies doing business in Iran from the effects of U.S. sanctions. Still, France has not imported any crude oil or condensate from Iran since June, while, Italy’s and Spain’s imports in September fell by 27,000 b/d and 15,000 b/d from levels seen at the first half of 2018.

Tankers used as floating storage

As international shipping operators have decreased operations with Iran, but Iran has continued to export largely through the state-run National Iranian Tanker Company (NITC) and the Islamic Republic of Iran Shipping Lines.

Trade press reports indicate that as countries continue to decrease imports from Iran, some of Iran’s shipping fleet is already being used as floating storage, where crude oil is placed onto ships and stored indefinitely. ■

How analytics are giving process industries the edge

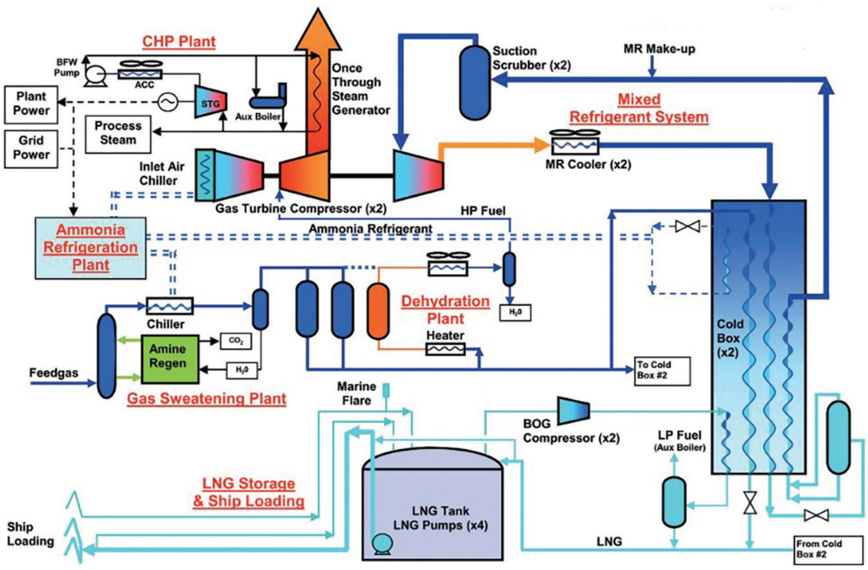
Unplanned downtime can cost an LNG facility as much as $4 million per day. With potential costs so high, profitability is largely linked with unplanned downtime. According to GE Power estimates, unplanned shutdowns in the process industry globally cost 5% of total annual production — that's as much as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

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.

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. ■



Improved liquefaction process

LNGo solution allows Altagas to monetize stranded gas

Dresser-Rand, part of Siemens Group, has commissioned an LNGo-HP (high-pressure) micro-scale natural gas liquefaction system for Altagas Ltd. in Dawson Creek, British Columbia, Canada. Producing approximately 30,000 gallons of LNG per day since January 25, 2018, the Dawson Creek facility allows Altagas to scale production in line with demand. The LNGo-HP system converts diesel and other fuels to natural gas, enabling users to monetize stranded gas deposits.

The micro-scale LNGo solution can be deployed in rough terrain or remote regions, eliminating the need to establish an expensive gas pipeline infrastructure or arrange for long-distance trucking of LNG from centralized plants to point of use. It can function as a decentralized solution where the requisite pipeline infrastructure is lacking, or as an onsite solution to reduce or eliminate flaring of petroleum gas at, for example, oil rigs or producing gas fields.

“We take pipeline natural gas and separate it into a feed gas stream and a waste gas stream. The waste gas is used to fuel the Siemens gas engine generator sets which power the LNGo-HP equipment. The feed gas is liquefied in the process to produce LNG," explained Michael Walhof, Sales Director for Distributed LNG Solutions for the Dresser-Rand business.

For the Altagas project in Dawson Creek, Siemens' scope of supply included one LNGo-HP system, site civil works, building construction, mechanical and electrical integration, commissioning, startup, and operator training. The LNGo system consists of modules which include two Siemens gas engines, two Dresser-Rand MOS reciprocating compressors, three Siemens MV motors, Siemens variable frequency drives, and associated auxiliaries. The plant, with a footprint of approximately 2,500 square meters, was deployed directly at the site.

Dresser-Rand commissioned its first LNGo-LP (low-pressure) micro-scale natural gas liquefaction system in 2016 at the Ten Man LNG facility in Pennsylvania, U.S. Here, the LNGo technology enables the operator, Frontier Natural Resources, to monetize stranded gas assets at Tenaska Resources' Mainesburg field, located in the Marcellus Shale. ■

Sempra get draft EIS for Port Arthur LNG in Texas

Sempra Energy, developer of the Cameron LNG export plant in Louisiana, has received its draft environmental impact statement from regulators for the proposed Port Arthur LNG project in Texas, comprising the largest liquefaction Trains planned so far for a Gulf Coast venture.

A draft environmental impact statement issued by the Federal Energy Regulatory Commission (FERC) found that the liquefaction plant and two associated pipelines would do some harm to the environment, "but these impacts would be reduced to less-than-significant levels" by mitigation measures.

The Port Arthur LNG project is moving forward without Australian LNG producer Woodside Petroleum, operator of the North West Shelf and Pluto LNG plants in Western Australia.

Sempra said in July 2018 it had been informed by Woodside that the Perth-based company was not proceeding with its Port Arthur investment and would be pursuing other capital expenditure plans instead.

A comment period on the FERC document issued for Port Arthur LNG closes on November 19 and three public information sessions are scheduled for October.

"We considered the cumulative contributions of the proposed projects in specific impact areas," said the FERC.

"As a part of that assessment, we identified existing projects, projects under construction, and reasonably foreseeable projects. These included existing LNG terminals and future LNG liquefaction projects and dredging projects," added the report. "This also included areas where the Louisiana Connect Project could be connected with another proposed pipeline project (the Driftwood Pipeline Project)," it said.

"We conclude that the contribution to impacts on resources affected by the Projects would not result in significant cumulative impacts," stated the FERC.

Rendering of the proposed Port Arthur LNG facility

The FERC review covered the Port Arthur liquefaction plant proposed for Jefferson County, Texas, with 13.5 million tonnes per annum of output as well as the Texas Connector and Louisiana Connector pipelines.

"Each liquefaction Train would consist of a feed gas pre-treatment unit, heavy hydrocarbon removal unit and liquefaction unit," said the report. "Natural gas would be transported via the Texas Connector and Louisiana Connector Projects to the feed gas pretreatment facilities, which would remove any impurities from the natural gas, including particulates, mercury, hydrogen sulfide, carbon dioxide and water," it added.

The draft EIS addressed the potential environmental effects of the construction and operation of the various proposed facilities. These include two liquefaction Trains, each with a capacity of 6.73 MTPA, three LNG storage tanks, each with a capacity of 160,000 cubic metres, a new marine terminal with two LNG vessel berths, an area for support vessels, an LNG transfer system and truck-loading areas. ■

Williams gets FERC approval to place Atlantic Sunrise in service

Federal Energy Regulatory Commission (FERC) has approved Williams' request to place its Atlantic Sunrise pipeline project into full service. Operations commenced in early October, increasing design capacity of the Transco pipeline for natural gas from Marcellus Shale by 1.7 billion cubic feet per day (Bcf/d), or approximately 15%, to 15.8 Bcf/d.

"This project makes the largest-volume pipeline system in the country even larger," said Alan Armstrong, Williams president and CEO. "In the process, the project further strengthens and extends the bi-directional flow of the Transco system, directly connecting Marcellus gas supplies with markets as far south as Alabama."

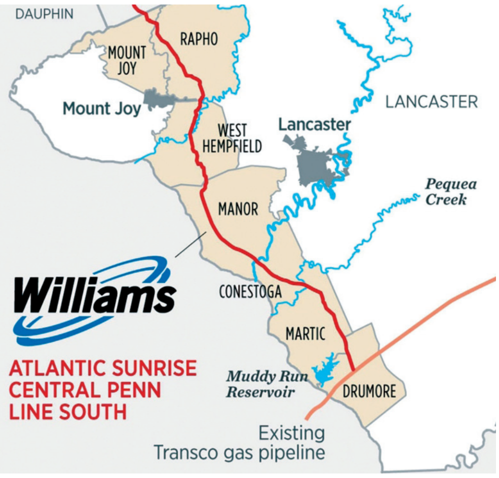
The project is significant for Pennsylvania and natural gas-consuming markets all along the East Coast. Mr Armstrong underlined it "is alleviating infrastructure bottlenecks and providing millions of consumers direct access to one of the most abundant, cost-effective natural gas supply sources in the country."

Construction on the Pennsylvania part of the pipeline started in September 2017. Works included the installation of 186 miles of greenfield pipe, 12 miles of pipe looping, 2.5 miles of pipe replacement, two new compressor stations and compressor station modifications in five states.

The Central Penn Line – the greenfield segment of Atlantic Sunrise – is a joint venture of Transco and Meade Pipeline Co (Meade), which is owned by WGL Midstream, Cabot Oil and Gas and EIF Vega Midstream.

The in-service placement of Atlantic Sunrise also boost shipment trough the 10,000-mile pipeline network Transco by about one-sixth. Transco's mainline extends 1,800 miles from South Texas to New York City. Overall, the extended pipeline system is one of the key providers of cost-effective natural gas services that reach U.S. markets in 12 Southeast and Atlantic Seaboard states. Customers served with natural gas from Transco are in major metropolitan areas, including New York, New Jersey and Pennsylvania.

The multi-billion dollar private infrastructure investment is supporting current and future natural gas production and is expected to boost employment and tax revenues for the state of Pennsylvania. "Projects like Atlantic Sunrise are allowing Pennsylvania to maximize the tremendous economic and energy benefits of the Marcellus Shale, spurring renewed investment into the manufacturing sector and creating opportunity for Pennsylvanians across the state," commented the President of the Pennsylvania Chamber of Business and Industry, Gene Barr. ■



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