Oil and Gas News Briefs
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Mideast national oil companies see profit and growth potential in LNG

(Bloomberg; June 18) - A new breed of investors is expanding into liquefied natural gas, offering billions of dollars for new projects and squeezing out established players. With billions of dollars at their disposal and strong government backing, national oil companies — primarily from the Mideast — have been splurging on global LNG production, with capacity set to nearly double in the next 10 years. Lured by the ballooning profits of current industry leaders such as Shell, they're making bold moves, as Abu Dhabi's $19 billion offer for Australian LNG producer Santos this week indicated.

Saudi Aramco has just positioned itself among the world's biggest LNG players to supply energy-hungry Egypt, and QatarEnergy, a major supplier for years, is proceeding with developing its export project in Texas. While still overshadowed by oil in terms of its importance in the global energy system, LNG is seeing faster growth and more sustained demand thanks to its role as a transition fuel backing up renewables.

But many projects have been held back by delays and cost overruns, and are in need of cash to make it across the finish line. For Gulf nations, it offers a chance to pursue more international heft in energy, finance and geopolitics, as well as diversify their oil-focused economies. "LNG seems to be still the best bet across all hydrocarbon commodities," said Ogan Kose, a managing director at Accenture. Margins from investing in and trading LNG are "almost unheard of in any other hydrocarbon commodity."

"One of the issues on the market has been the issue of finding capital," said Massimo di Odoardo, a vice president at Wood Mackenzie in London. "Increasingly you are seeing more private capital helping those projects to cross the line," with part of that coming from national oil companies. As many of these Middle Eastern firms will also act as LNG offtakers before selling the cargoes onward, there's less need for project developers to sign deals directly with buyers in order to reach a final investment decision.

Energy analysts question costs and viability of Alaska LNG project

(Natural Gas Intelligence; June 18) - The massive costs and potential commercial risks of the long-delayed Alaska LNG export project still remain significant impediments for development despite the renewed interest and strong political support that has created momentum for the venture, according to a Rapidan Energy Group analysis. The project's $44 billion price tag is out of date, the analysis said, though the developers are working to update it. Rapidan noted the second phase of the project alone could cost up to $60 billion based on current large-scale LNG projects along the Gulf Coast.

An affiliate of Glenfarne Group took over the 20 million-tonne-per-year project from the state of Alaska. Glenfarne spokesperson Micah Hirschfield pointed to the project's closer proximity to premium markets in Asia that could give it an advantage and make it attractive to offtakers. "The project's feed gas cost and shipping advantages alone offset tens of billions of dollars" of capital expenditure equivalent "compared to Gulf Coast and other LNG export projects that can cost two to three times as much," he said.

But Rapidan said the first phase of the project — just the gas pipeline — is uneconomic alone given the steep costs and challenges of building the line in remote and complex terrain. Rapidan noted the costs for similarly complex projects such as the 416-mile Coastal GasLink pipeline built to move gas across rugged terrain to the LNG Canada export terminal in British Columbia. The system's cost ballooned from initial estimates near $5 billion to a total of about $15 billion by the time it was completed last year.

Glenfarne has enlisted engineering, procurement and construction firm Worley for additional design work and to update the cost estimate for the pipeline, which it is aiming to sanction this year. "Given the scale and complexity of Phase 1, we doubt that Worley or any other EPC (engineering, procurement and construction) contractor would undertake construction on a fixed-price basis, as the financial risk is too great," Rapidan wrote in the report. "Any cost overruns would likely be borne by the project's financiers."

Financing for the entire project of the pipeline, gas treatment plant and liquefaction plant "now seems to hinge on a mix of public and private capital, potentially tied to trade agreements with Japan, South Korea, Taiwan and India," Rapidan said. However, Rapidan analysts led by Alex Munton, the firm's director of global gas and LNG, said "we doubt they will translate into binding financial commitments and our base case is that the project does not reach a final investment decision."

LNG Canada plant expected to start production this weekend

(Reuters; June 18) - Canada could produce its first liquefied natural gas this weekend from the LNG Canada export facility in Kitimat, British Columbia, two people familiar with the startup of the plant told Reuters on June 18. The facility will be the first LNG facility in North America with direct access to the Pacific coast, significantly reducing sailing time to Asian markets. When fully operational, it will have a capacity to export close to14 million tonnes per year.

"We began cooling down Train 1 on Monday (June 16) and as long as there is no unforeseen difficulty we expect to produce LNG" by the weekend, June 21-22, one of the people familiar with the startup told Reuters. The first LNG cargoes are expected by the middle of this year, LNG Canada said. Train 1, which has a capacity of 6.5 million tonnes per year, or half of the total output of the plant, has had difficulties with one of its lines and it will only produce at half its capacity until it is able to solve the problem, one of the two sources told Reuters.

An LNG tanker is on its way to Kitimat, according to LSEG ship tracking data. The vessel is expected to arrive on June 29. It is now seven years since the partners — Shell, Petronas, PetroChina, Mitsubishi and Korea Gas — gave the project a financial go-ahead. Once the terminal enters service, Canadian gas exports to the U.S. will likely decline, traders said, as Canadian energy firms will have another outlet for their fuel and will sell more to other countries. For now, the U.S. is the only outlet for Canadian gas.

Shell says low-cost gas makes LNG Canada exports more attractive

(Reuters; June 17) - Buyers are attracted to Shell's LNG Canada project because it uses the Canadian Alberta Energy Co. (AECO) price index as a benchmark, which is lower than the Henry Hub price in the U.S., the company's chief executive said on June 17. "What is particularly attractive about LNG Canada in today's world, retrospectively, is the AECO indexation," Shell CEO Wael Sawan said at the Energy Asia conference, adding that there will be more supply of AECO gas at lower prices.

"And so that differential between AECO and Henry Hub, not to mention the proximity to Asia, all of that makes it a particularly attractive project, and it will be one of the lowest-carbon projects anywhere in the world," he said. The AECO Storage Hub price on June 16 was at 96.6 Canadian cents (71.4 U.S. cents) per million Btu, according to data from SNL Financial. That compares with a Henry Hub futures price of $3.746.

The LNG Canada project, the country's first export facility, is expected to produce 14 million tonnes per year. The plant in Kitimat, British Columbia, is expected to produce its first LNG this month. LNG Canada is a joint venture of Shell, Petronas, PetroChina, Mitsubishi and Korea Gas.

Israel-Iran fighting could escalate into worst-case energy crisis

(Reuters columnist; June 17) - Critical energy infrastructure in Israel and Iran has not escaped unscathed from the first few days of the countries' escalated conflict. Worst-case scenarios have yet to be realized, but the war is already having a notable impact on energy production and exports in both countries. Investor focus remains squarely on the Strait of Hormuz, a narrow and vital waterway between Iran and Oman in the Mideast Gulf through which between 18 million and 19 million barrels per day of crude oil and fuels flow, nearly a fifth of the world's consumption.

And 85 million tonnes of liquefied natural gas from Qatar and the United Arab Emirates went through the strait last year, about 20% of global demand. Disrupting maritime activity would thus severely impact oil and gas markets, pushing oil prices much higher, possibly into three-digit territory. This doomsday scenario has not yet played out, but disruption to both Iran's and Israel's energy industries has been meaningful.

Perhaps most notably, Iran's oil exports appear to have essentially ground to a halt in recent days. Total Iranian crude and condensate oil exports this week are currently forecast to reach 102,000 barrels per day, compared with a weekly average of 1.7 million so far this year, according to analytics firm Kpler. Exports from Kharg Island, where Iran exports over 90% of its oil, appear to have completely halted since June 13. However, Iran has roughly 27.5 million barrels stored in tankers outside the Gulf, according to Kpler data, which would enable it to sell oil for a few weeks.

If a ceasefire is quickly reached, the ultimate impact on energy markets could be relatively limited. But given how much this conflict has escalated in only a few days, the worst-case scenarios cannot be fully discounted.

China could lose access to discounted oil if Iran exports stop

(Wall Street Journal; June 17) - Israel hasn't attacked Iran's energy export hubs so far. If it does, China could find itself cut off from cheap oil. Iran exports about 1.7 million barrels of crude a day. Most countries won't touch Iran's U.S.-sanctioned crude, so Tehran is forced to sell at a discount and find covert ways to get it to the market. It uses a "dark fleet" of tankers that sail with their transponders turned off to ship cargoes of oil.

More than 90% of Iran's oil exports now go to China, according to commodities data company Kpler. Most of it is bought by small Chinese "teapot" refineries clustered in the Shandong region that operate independently from state-owned oil companies. They switched to illicit Iranian oil en masse in 2022 to protect their profit margins. The discount on Iran's oil compared with a similar grade of non-sanctioned crude such as Oman Export Blend is currently around $2 a barrel, according to Tom Reed, vice president of China crude at commodity data provider Argus Media.

The gap has narrowed recently because of worries that conflict with Israel and stricter enforcement of U.S. sanctions could disrupt Iranian supply. With few buyers for Iranian oil, Chinese refineries have leverage. Last year, an Iran Chamber of Commerce official characterized the trading relationship as "a colonial trap." As the sanctioned oil is paid for in Chinese renminbi rather than dollars, Iran has few choices about where to spend its earnings except on Chinese goods, reinforcing its dependency on one country.

[World’s oil companies seek to reassure investors of future business]

(Financial Times; London; June 17) - The world’s largest oil companies have endured a lost decade in the stock market, struggling to convince investors they can grow in a world where demand for their main product is expected to peak in the coming years. The S&P Global Oil index, which tracks 120 leading international oil producers, is no higher now than it was in 2015. With the exception of a sharp dip during the pandemic, it has flatlined while investors have flooded into Big Tech.

Oil majors are no strangers to boom-and-bust cycles. But now the challenge may be structural. The rapid adoption of electric vehicles, especially in China, has surprised the industry. Many oil majors now concede that their production will probably peak within the next decade. “There’s no doubt that in the grand scheme of things, this is a sunset industry,” said Paul Gooden, head of natural resources at asset manager Ninety One. “We can debate how far the sunset is away, but companies need to recognize that.”

László Varró, Shell’s head of scenario planning, echoes the sentiment. “There is very little doubt that peak oil demand is coming,” he said. The oil sector remains split on how imminent the peak is, and how to respond. European companies have acknowledged the transition and have begun to pivot. U.S. firms, along with Mideast state producers, remain more bullish. ExxonMobil doesn’t see any decline in oil demand until 2050 and is expanding production. Chevron has also played down the prospect of a near-term peak.

To shore up their investment cases, oil companies stress that peak demand does not mean the end of oil. Use is expected to persist for decades — driven by petrochemicals, aviation, shipping and road transport in emerging markets — especially if politicians scale back their climate ambitions and focus on energy security and affordability.

[Subsidiary of Tokyo Gas adds to its U.S. shale holdings]

(Journal of Petroleum Technology; June 16) - Japanese energy firms are seeking U.S. liquefied natural gas supplies, with many signing long-term offtake agreements, while others, such as Tokyo Gas, are eyeing strategic investments to become part of the North American gas value chain from exploration and production to liquefaction and global LNG marketing.

In April, Japan’s largest city gas supplier, Tokyo Gas, through its U.S. subsidiary TG Natural Resources (TGNR), purchased together with Castleton Commodities International a 70% stake in Chevron's East Texas gas assets which extend into the Haynesville Shale formation near Louisiana. The sale, at $75 million in cash and a $450 million capital carry to fund future Haynesville development, builds on TGNR’s $2.7 billion acquisition in 2023 of Rockcliff Energy from Quantum Energy Partners.

Tokyo Gas has confirmed it is also "actively pursuing" a stake in Woodside's Louisiana LNG facility to realize its broader strategy of not only securing U.S. gas supply but of creating an integrated U.S. gas value chain. TGNR has acquired through the Chevron deal 71,000 net contiguous and largely unexplored acres in Panola County, Texas. According to its website, TGNR owns more than 410,000 net acres and produces net volumes of more than 1 billion cubic feet of gas per day, primarily from the Haynesville and Cotton Valley formations in east Texas and northern Louisiana.

Mitsubishi in talks to buy U.S. Haynesville shale producer

(Bloomberg; June 16) - Mitsubishi is in advanced talks to buy the assets of Aethon Energy Management for close to $8 billion, people familiar with the matter said, in what would be the Japanese conglomerate's biggest acquisition ever. Tokyo-based Mitsubishi could announce a deal with the U.S. energy-focused investment firm in the next couple of months, according to the people. Abu Dhabi National Oil Co. had also been considering a potential transaction involving Aethon, Bloomberg News reported in April.

A deal with Mitsubishi would likely be structured as a purchase of Aethon's portfolio, which includes natural gas production operations and midstream assets, some of the people said. While a deal is close, talks could still be delayed or falter, the people said, asking not to be identified discussing confidential information. It's also possible another bidder could emerge for Aethon. Dallas-based Aethon is among the most active drillers in the Haynesville shale basin that straddles eastern Texas and northern Louisiana. Aethon's gas assets are close to several LNG export terminals along the Gulf Coast.

Mitsubishi, one of Japan's major trading companies, is a key supplier of liquefied natural gas and has a stake in a U.S. export facility in Louisiana. Japan's government sees the artificial intelligence boom potentially lifting power demand over the next decade, and has urged the nation's private firms to invest in gas. An acquisition of Aethon would be the largest on record by Mitsubishi, Bloomberg-compiled data show.

U.S. LNG developer says cost of expansion project up 10%

(Offshore Energy; June 13) - Houston-headquartered energy player NextDecade has revealed a 10% price increase from a previous contract and a new multibillion-dollar deal with Bechtel Energy, a U.S.-based engineering, procurement, construction and project management company, enabling the contractor to handle work on two additional trains for a liquefied natural gas export project at the Port of Brownsville, Texas.

Following a final investment decision for three trains at Phase 1 of the Rio Grande LNG project in July 2023, totaling 18 million tonnes per year of LNG production capacity, Bechtel won a $4.3 billion lump-sum turnkey engineering, procurement and construction contract for Train 4 and related infrastructure at the Rio Grande site. That price expired on Dec. 31, 2024, and NextDecade and Bechtel have agreed to a new contract at $4.77 billion. That price is good through Sept. 15.

“Commercialization of Train 4 is complete, and the company has started the financing process for Train 4 and related infrastructure. Subject to obtaining adequate financing, NextDecade expects to achieve a positive FID on Train 4 before the end of the pricing validity period for the Train 4 EPC contract,” the company said. NextDecade also is working to commercialize a fifth liquefaction train, which Bechtel would construct. The first phase of three trains is projected to cost $18 billion.

TotalEnergies expects to restart Mozambique LNG work this summer

(Reuters; June 18) – TotalEnergies expects its $20 billion Mozambique liquefied natural gas export project to resume development "this summer,” CEO Patrick Pouyanne said on June 18. He was asked about the timing during a session at the Japan Energy Summit in Tokyo. Covered by force majeure since 2021, following insurgent attacks in the area, the project includes development of the Golfinho and Atum gas fields in the Offshore Area 1 concession and the building of a two-train liquefaction plant onshore.

The terminal will have a capacity of 13.12 million tonnes per year. TotalEnergies is the project's operator with a stake of 26.5%. Mitsui holds 20%, while Mozambique's state-owned ENH has 15%. Indian state firms and Thailand's PTTEP own the rest.

Northern Mozambique has been struggling to contain an Islamist insurgency. Now, the situation is improving with the help of the Rwandan authorities — and Rwandan troops financed by the European Union, which has the most interest in the project restarting as a major gas importer that is trying to completely give up Russian energy, including gas. In addition to the insurgence that has threatened the project, there is strong environmentalist opposition to the project, with even governments getting involved.

Chinese trader says more flexibility needed in LNG deals

(Reuters; June 17) - PetroChina International, the trading arm of the Chinese oil major, says it is interested in North American liquefied natural gas supplies as it seeks to reduce trading risk by seeking flexibility in supply deals, said a company executive on June 17. "If I look at our portfolio today, I think we're slightly overweight on duration. I think we signed too many, very long-term, take-or-pay SPAs (sales and purchase agreements)," said Zhang Yaoyu, assistant chief executive and global head of LNG.

Asia and China as a whole need more flexibility in their LNG term deals, and that is something that PetroChina International actively tries to "derisk upon,” he said. "We firmly believe the diversification process has significantly improved the resiliency of the portfolio, and that's something that we have been working really hard on."

Zhang also said that the company's portfolio is slightly overweight on inflexible term supply volumes, and it would be interested in taking on some North American positions. LNG buyers and traders may seek term contracts without destination restrictions so they can resell cargoes when demand is low. Many supply deals from U.S. sellers do not have destination restrictions.

LNG export projects in Mexico encounter delays

(Gas Outlook; June 17) - Mexico's hopes of building up a significant liquefied natural gas export industry are losing momentum as major projects suffer delays. Most of the proposed projects in Mexico would use U.S.-sourced gas. The half dozen LNG projects proposed for Mexico's Pacific Coast would import gas from the Permian Basin in Texas. The 7.8-million-tonne-per-year Amigo LNG project located in Sonora, Mexico, has quietly admitted that progress on the project has stalled.

Backers of the project — the Singapore-based LNG Alliance — said the project will not start until the second quarter of 2028, according to its website. The startup date had previously been listed as 2027, which was a significant delay from the original target date of 2025. The delay could further complicate the status of the project's permits. Because Amigo LNG is using U.S. gas, it needs a permit from the U.S. Department of Energy. The Amigo LNG export authorization expires in December 2027. The project won't be online by then, so it will need to reapply for a permit or obtain an extension.

The much larger Saguaro LNG project is also at a standstill, crippled by uncertainty and investor risk. It has failed to secure the $15 billion to $20 billion in financing it needs to build the project, despite having signed up customers. Investors are balking at providing financing because construction costs are largely unknown. The price tag for building a long-distance gas pipeline through the Sonoran Desert, large swathes of which are controlled by organized crime groups, is a big question. The company repeatedly promised that an FID was imminent, most recently stating late last year that an FID would occur in early 2025. Those deadlines have come and gone.

Takeover price for Santos reflects value of its LNG business

(Upstream; June 16) - The share price of Australian gas-focused company Santos increased 10% following the June 16 announcement of a potential US$18.7 billion takeover by an Abu Dhabi-led consortium, but the stock was still trading below the offer price which exemplifies why Santos has been attractive to buyers in recent years. Santos and the analysts who cover the company have long observed that investors on the Australian Stock Exchange have not adequately valued the company’s liquefied natural gas business, which has blossomed since 2020.

That was when Santos acquired the Darwin LNG facility from ConocoPhillips, while the following year saw Santos acquire Oil Search, which delivered the supreme jewel in Santos' crown — the gas discoveries and LNG assets in Papua New Guinea. Despite those acquisitions, Santos shares have never in the past five years reached the A$8.89 (US$5.76) that Abu Dhabi’s XRG consortium has offered per share. Australian analysts for several years have pointed out that Santos has been fair game for acquisition.

Santos’ LNG asset base is led by Papua New Guinea, followed by Gladstone LNG in Queensland. Darwin LNG is currently not producing but is being rebooted to receive gas volumes later this year from Santos' Barossa field offshore Australia, while an additional liquefaction train is in the cards. Its LNG business took in US$828 million of revenue in the first quarter this year on production of 1.36 million tonnes. Santos also has a domestic gas growth opportunity in the Greater Dorado play of Western Australia’s Bedout sub-basin where a significant gas and oil reserve have been discovered.

Australian state wants to ensure Santos sale in best interests

(Australian Broadcasting Corp.; June 16) - The South Australian government has threatened to intervene if a nearly $30 billion takeover bid for the state's largest company, Santos, is "not in the interests of South Australians.” Santos has received a takeover offer from a consortium led by XRG, the international investment arm of the state-owned Abu Dhabi National Oil Co. The Santos board has indicated it intends to unanimously recommend shareholders vote in favor of the transaction.

The agreement is subject to approval from the Foreign Investment Review Board, Australian Securities and Investments Commission and National Offshore Petroleum Titles Administrators, as well as other authorities in Papua New Guinea and the U.S. Santos, founded in 1954 as South Australia and Northern Territory Oil Search, is South Australia's largest company. It has assets in the Cooper Basin in far northeastern South Australia, Gladstone in Queensland, and in Western Australia and Papua New Guinea.

XRG said it intends to maintain Santos's headquarters in Adelaide and its "brand, and operational footprint in Australia. Energy and Mining Minister Tom Koutsantonis said having Santos headquartered in Adelaide was of "strategic and vital importance to the state. … We're going to fight to keep it here.” Koutsantonis added that the takeover was "not a foregone conclusion.” He said the state government recently passed legislation that "requires our consent for change of license ownership in the resources sector. … We've got legislation which puts us at the table.”

EU sets out plan to stop all Russian gas imports by end of 2027

(Bloomberg; June 17) - The European Union's proposed ban on all Russian natural gas by the end of 2027 sets the stage for heated debate, with some member states nervous it will boost energy prices and cost companies millions of euros in legal fees. The European Commission on June 17 set out the legislation needed to end the bloc's reliance on pipeline and liquefied natural gas supplies from Moscow, starting by prohibiting new deals from next year.

Supplies under existing contracts shorter than one year will be stopped from June 17, 2026, at the latest, with an exemption for landlocked countries such as Hungary and Slovakia. There's broad political support for the commission's push to sever ties with Russia to avoid further risks to EU energy security, despite opposition from those central European nations. While no longer the bloc's biggest supplier, Russia still accounts for almost a fifth of European suppl.

"Russia has repeatedly put at risk Europe's energy security," Dan Jorgensen, the EU's energy commissioner, said in Strasbourg. "We have decided to close the tap." A ban on shipments under existing longer-term deals would take effect by the end of 2027. Still, negotiations over the final shape of the deal are set to kick off with some countries unsure about the feasibility of the proposal. Talks need to conclude by the end of the year for the phaseout to start in line with the commission's plan on Jan. 1, 2026, a tight timeline for what is often a lengthy decision-making process in the EU.

EU faces challenges in relying on Russia's nuclear fuel, technology

(Financial Times; London; June 16) - The European Union has delayed plans to wean the bloc off a small but key reliance: Russian nuclear technology. Since Moscow's 2022 invasion of Ukraine, EU countries have paid more than €200 (US$230 billion) billion to Russia for fuel. Coal and oil imports have been sanctioned and gas could be phased out by 2027. Nuclear fuel accounted for only about €700 million of the €22 billion paid to Russia in 2024, according to the think-tank Bruegel. But officials have warned that the risk to EU energy security is huge if Moscow suddenly cut off nuclear fuel supplies.

"The uranium supply chain is very complex," said Ben McWilliams, affiliate fellow in climate and energy at Bruegel. A gradual phaseout would be needed, he said. The EU has 101 nuclear reactors, of which 19 are Soviet VVER designs. The bloc relies on Russia for about 20% to 25% of its natural, converted and enriched uranium. Reactors across the EU often buy Russian spare parts or require maintenance expertise. Russia's dominance of the sector poses a severe challenge. Its state nuclear company "is one of the biggest companies in all sectors of nuclear markets," said Dmitry Gorchakov, nuclear adviser at the non-governmental organization Bellona.

The European Commission ideally would like the European nuclear sector to be free of Russian imports by the 2030s. But on June 13, it warned that €241 billion of investment was needed to build out the domestic nuclear supply chain. The move to phase out Russian imports is in line with efforts in other Western countries. Canada has banned all Russian uranium imports and the U.K. has put 35% tariffs on Russian enriched uranium. The U.S. last May passed a law to stop Russian uranium imports from 2028.

Economists' report says high costs hold down gas use in India

(World Coal; June 12) - A new report by the Institute for Energy Economics and Financial Analysis finds little evidence that liquefied natural gas is displacing coal in India's largest coal-consuming sectors. This is despite frequent claims from the global oil and gas industry that LNG serves as a transition fuel from coal to cleaner energy. In the power sector, which accounts for 70% of India's coal demand, gas and LNG have been squeezed out of the generation mix due to high costs and their inability to compete with cheaper resources like renewables and coal.

The share of gas-fired power in India's electricity mix has fallen to less than 2% in fiscal year 2025, from 13% in fiscal year 2010. This is due to limited supplies of domestic gas, along with uncompetitive prices for imported LNG. For instance, average imported LNG prices in fiscal 2024 were roughly nine times the cost of domestically produced coal and more than twice that of coal imported from Indonesia, India's largest coal supplier.

The report highlights that in fiscal year 2025, 31 gas-fired power plants — with a combined capacity of nearly 8 gigawatts and representing 32% of the country's total gas power capacity — did not generate any electricity, rendering them stranded assets. In April, 5.3 GW of this 8 GW was retired due to inoperability. There may be room for coal-to-gas switching among smaller industries, especially as the country expands its national gas grid, but the suitability of LNG will depend on pricing, infrastructure and the competitiveness of alternative fuels, the report said.

Four LNG import terminals proposed for Australia's East Coast

(Reuters; June 12) - Australia could start imports of liquefied natural gas in 2027 to address potential supply shortages, based on developments at import terminal projects along its East Coast. The country's competition regulator has said coastal population centers may face a long-term gas shortfall amid higher demand and a decline in gas production. There are four import projects being advanced, consisting of floating storage and regasification units (FSRU) that will send gas by pipeline to shore for consumption.

The Port Kembla terminal is commissioned and plans to import around 2 million tonnes of LNG a year, starting in 2027. The start-up date was delayed from 2026 after operator

Squadron Energy extended the sub-charter of its FSRU to Egypt's EGAS until the end of 2026, according to a company spokesperson. The terminal is already connected to a gas pipeline, according to the Australian Energy Market Operator.

Singapore-based Atlantic, Gulf and Pacific LNG has agreed to acquire Australian energy infrastructure company Venice Energy and will develop its Outer Harbor import terminal in South Australia. The terminal, pending a final investment decision, is expected to be completed by the end of 2026, with the first gas to flow into the system by mid-2027.

The government has cleared construction for Viva Energy's terminal in Geelong, the company said May 30. The terminal will use an FSRU with a 4.35-mile pipe to Victoria, at a capacity of 2.9 million tonnes of LNG a year. Start-up is expected in 2028.

Vopak has started talks with gas suppliers and offtakers for its LNG import terminal in Victoria and expects to make a final investment decision in 2026-2027. It aims to start operations in 2029. Gas would be moved to Victoria through a 12-mile underwater line.

Brazil auctions onshore, offshore drilling sites near Amazon River

(The Associated Press; June 17) - Brazil auctioned off several land and offshore potential oil sites near the Amazon River on June 17 as it aims to expand production in untapped regions despite protests from environmental and Indigenous groups. The event came months before Brazil is to host the U.N.'s first climate talks held in the Amazon. The protesters outside the auction venue warned of potential risks that oil drilling poses to sensitive ecosystems and Indigenous communities in the Amazon.

Most of the 172 blocks offered are in areas with no current production, such as 47 offshore locations close to the mouth of the Amazon and two sites inland in the Amazon near Indigenous territories. Nineteen offshore blocks were awarded to Chevron, ExxonMobil, Petrobras and China National Petroleum Corp. The oil companies see the area as highly promising because it shares geological characteristics with Guyana, where some of the largest offshore oil discoveries of the 21st century have been made.

Under public pressure from President Luiz Inácio Lula da Silva, the Brazilian Institute of the Environment and Renewable Natural Resources approved an emergency plan allowing state-run Petrobras to conduct exploratory drilling in a block near the mouth of the Amazon River, the last step to grant an environmental license. "It's regrettable and concerning that blocks are being acquired in a basin that has not yet received environmental licensing," Nicole Oliveira, executive director of the environmental nonprofit Arayara, which tried to block the auction in court.