Gas to Power Journal
Peakload Power and Energy Storage

Focus on supply security, carbon pricing & CCS

Weekly News 5 April 2024

Egypt mulls importing LNG to pre-empt risk of shortage this summer

Egyptian utility buyers are considering purchasing LNG cargoes to boost storage levels before peak gas demand for power generation sets in during the summer months. Buyers inquired about deliveries starting in mid-April and through the summer, sourced either via an existing regas terminal in neighbouring Jordan or through a new floating terminal.

Importing LNG would be a major shift for Egypt which largely ceased to buy the gas from abroad when the massive Zohr field increased production at home which eventually turned the country into a gas exporter. Now, the ongoing conflict between Israel and Hamas has substantially reduced the possibility to import pipeline gas from the Tamar field to balance demand swings, so LNG imports seem the only way out to avert future supply shortages.

The FSRU unit BW Singapore left Egypt's Ain Sukhna port in November after a charter agreement ended, leaving the country without a flexible import terminal to ensure security of supply. The government hence signed a deal with Jordan to use an estisting regas terminal in Aqaba, in case of emergency.

Chronic gas shortages last summer

Halts in pipeline gas deliveries from Israel had incurred chronic energy shortages in Egypt last summer and way into the autumn, with the public suffering repeated rolling blackouts. The US oil major Chevron had been permitted restart operations at the Tamar offshore gas field in November, following a 5-week suspension due to rocket attacks at the nearby Gaza strip. Gas export to Egypt ground to a halt, falling from 800 million cubic feet per day.

Egypt normally imports about 7 billion cubic feet per year (bcm/y) of natural gas from Tamar and Leviathan which helps meet domestic demand and feeds its two liquefaction plants – Idku LNG close to the city of Alexandria – and Damietta SEGAS LNG close to the Suez Canal.

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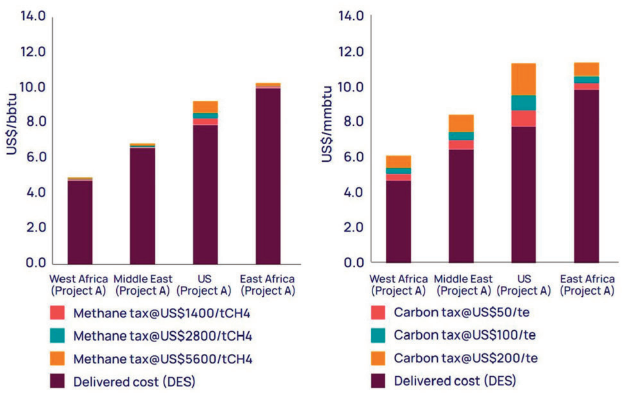
EU carbon tax on energy imports could split global LNG market

The global LNG market is at risk of bifurcating given that the European Union has extended its Emission Trading Scheme (ETS) to shipping, meaning LNG cargoes into Europe will soon be subject to a carbon tax. If these levies are applied, analysts warn it will push up European gas prices and create a two-tier LNG market.

If EU policy maker also include LNG in its Carbon Border Adjustment Mechanism (CBAM) – effectively placing an import duty on LNG at prevailing ETS carbon prices – then the global LNG market would split, predicts Massimo Di Odoardo, Vice President of Gas & LNG Research at Wood Mackenzie. "If taxes were limited to the EU, or even extended to Japan and South Korea, trade flows would likely be optimised elsewhere to mitigate the impact," he noted.

The environmental footprint of LNG is under increasing scrutiny. Though gas produces only half the carbon emissions of coal when combusted, liquefying natural gas is highly carbon intensive and plagued by methane

LNG delivered cost to Europe based on alternative methane and CO2 emission import taxes



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AGENDA

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The political imperative to avoid blackouts and to ensure the consistent availability of electric power at peak times has been a defining feature of the Sisi presidency. The collapse of the Mubarak regime and the brief rise and fall of the Brotherhood's Mohamed Morsi took place against a backdrop of a severe energy crisis.

Eager to avert electricity shortages, President Sisi struck an €8 billion deal with Siemens in 2020 to build the three mega power plants – Beni Suef, New Capital and Burullus (4.8 GW each) – together with its consortium partners, Orascom Construction and Elsewedy Electric. The three CCGTs, along with some smaller wind and solar PV installations, helped raise Egypt's installed power generation capacity to over 47 GW, and boosted the available reserve to 25.7% of installed capacity. ■

US gas production increased 4% in 2023, upward trend set to continue

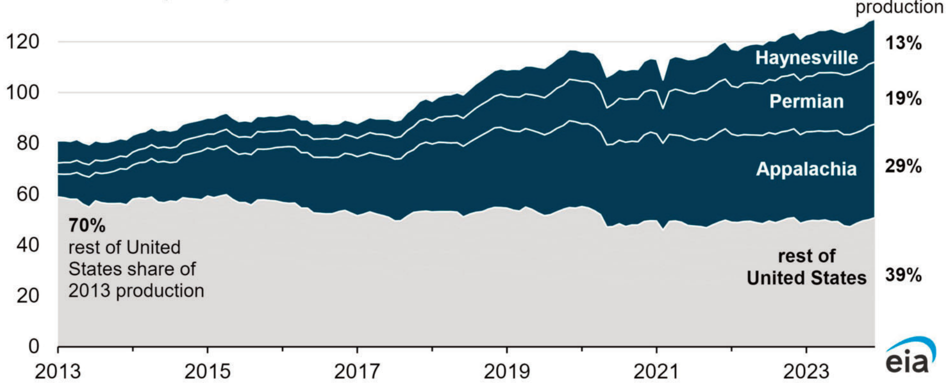
Gas production in the United States grew by 4%, or 5 billion cubic feet per day (Bcf/d) last year, to average 125 Bcf/d and analysts expect the upward trend to continue in 2024, albeit with a more modest pace. Dry gas production is forecast at about 103 Bcf/d this year because of low prices and a relatively stable rig count.

Appalachia, Permian, and Haynesville accounted for 59% of the entire natural gas production in the United States, similar to 2022, and dry gas drilling keeps catering for the majority of incremental supply growth. Though output at the Appalachia region grew by 3%, or 1.2 Bcf/d to reach 37.7 Bcf/d of gross gas production, analysts the region doesn't have enough pipeline takeaway capacity to transport more natural gas out of the region.

The Permian basin in western Texas and New Mexico produces the second-most natural gas, accounting for 19% of total US production. Unlike, in the Appalachia and Haynesville regions, gas in the Permian is largely produced as associated gas during oil production. WTI crude oil prices last year supported oil-directed drilling in the Permian, hence gross gas production in the Permian rose by 2.6 Bcf/d to average 23.3 Bcf/d. The average breakeven price in the Permian region during 2023 ranged from $58 per barrel to $61/bbl, according to data from a Dallas Fed Energy survey, but WTI crude oil prices last year were far higher than that averaging $78/bbl.

Production growth in the Haynesville region in Louisiana and Texas, meanwhile, slowed amid as comparatively low US gas prices reduced the number of active rigs to 49, compared to 55 in the previous year, hence production expanded at just 1.4 Bcf/d – less than the 2.1 Bcf/d growth in 2022. Analysts pointed out that shale gas plays at Haynesville are situated in deeper formation which are technically more challenging and more expansive to tap. ■

Monthly U.S. natural gas gross withdrawals by region (Jan 2013–Dec 2023)
billion cubic feet per day



Data source: U.S. Energy Information Administration, *Drilling Productivity Report*, *Monthly Crude Oil and Natural Gas Production Report*, and *Natural Gas Monthly*

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losses. Technology to reduce this is available, but buyers are reluctant so far to pay a premium for lower-emission LNG.

Not all LNG projects are equal: Measured in kilograms of carbon dioxide equivalent (kg CO2e), methane accounts for 5% to 15% of overall carbon intensity in LNG projects outside the United States. But for LNG projects in the US, methane can account for as much as 25% to 40%. This is largely due to higher levels of methane losses caused by extensive use of pneumatic devices and compressors associated with shale gas production. "With a range of 800 to 1400 kilograms CO2 equivalent per tonne (CO2e/t) of LNG, the US has some of the world's highest-emitting projects, with upstream reservoir type and pipeline distance to LNG plants adding to their high methane intensity," Di Odoardo pointed out.

Methane reduction remains the low-hanging fruit in emissions, so analysts suggest a tax on methane emissions of $2800 per tonne (t/CH4), equivalent to $100/t CO2e, will be effective in achieving its goal. But taxes imposed only in Europe will not achieve the required goal of large-scale decarbonisation of LNG projects globally and risk to split the market.

"If there is to be any material impact, a carbon price closer to $200/t CO2e will be required for LNG imports," says Di Odoardo. "Additionally, this would have to be introduced on a global level for it to be truly effective in reducing carbon intensity and that is unlikely to happen." So for now, all eyes are on European policy makers. ■

Wave of US oil & gas mergers continues in rush to buy drilling land

Diamondback's merger with Endeavor to form a $26 billion company continues the trend of US upstream companies seeking to boost output by snapping up rivals with rights to proven reserves. E&P firms in 2023 spent a record $234 billion on acquisitions, including Chevron's $53 billion deal to buy Hess and ExxonMobil splashing out $59.5 billion to get its grip on the shale group Pioneer Natural Resources.

These two mega deals boosted the share of corporate M&A to about 82% of total announced spending last year. Chevron's and ExxonMobil's announced acquisitions, respectively, are the largest by value in real terms since Occidental Petroleum in 2019 bought Anadarko Petroleum for $55 billion.

Large players snap up assets

The result of the recent consolidation is that large players own even more proved reserves and producing assets. Chevron, for once, is currently the largest oil and natural gas liquid (NGL) production in the US, accounting for 5% of the country's total output. If Chevron successfully acquires Hess Corporation, it could increase Chevron's share of U.S production to 6%, or just over 1.2 million b/d, based on Q3-23 data, US government analysts noted.

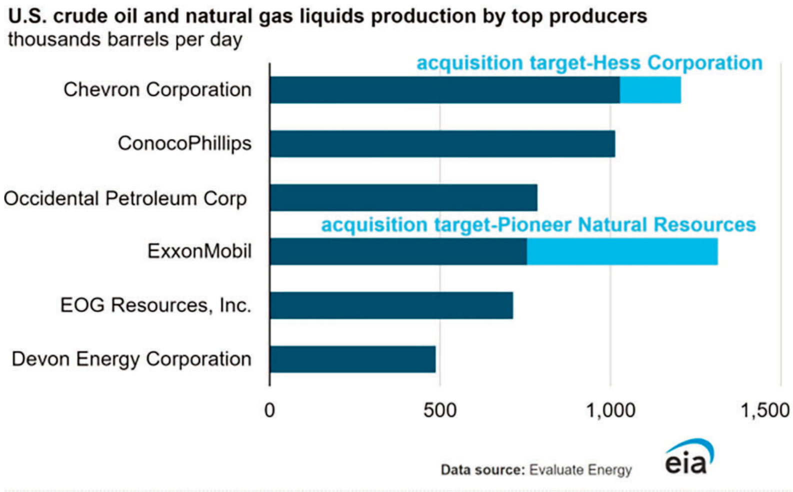
Similarly, ExxonMobil, the fourth-largest US crude oil and NGL producer, could potentially boost production to nearly 7% of the country's total – from about 750,000 b/d to 1.3 million b/d – if it completes the acquisition with Pioneer Natural Resources. Barring any other large production or asset ownership changes, recent M&A could make ExxonMobil the largest crude oil and NGL producer in the United States.

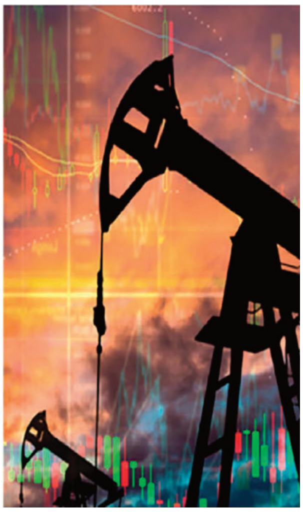
Rush for reserves in the Permian

Both Diamondback's takeover of Endevor and ExxonMobil's acquisition of Pioneer are spurred by the majors' drive to use their cash, accumulated over the past two years thanks to high oil prices, to buy up rivals with reserves in the oil-rich Permian basin. ExxonMobil said it expects that combining its 570,000 net acres in the Permian's Delaware and Midland Basins with Pioneer's more than 850,000 net acres in the Midland Basin will result in some 16 billion barrels of oil equivalent (BOE) worth of reserves.

As the main source of incremental crude oil production, the Permian Basin has reached record output of 430,000 b/d last year and government analysts anticipate 380,000 b/d between January and December 2024, which would make up 94% of forecast L48 production growth.

Sky-high oil and gas prices during the global energy crisis in 2022 made US upstream companies fast-track drilling and production, but prices have come down since then. Analysts expect crude oil price will begin to fall in the second quarter of 2024, as global stocks start to build, partially due to higher US production growth. Inventory builds are seen average 210,000 b/d this year, and the price of Brent is forecast to hover around $86 per barrel. ■





CPS Energy buys Talens 1,710 MW generation portfolio for $785 million

Texan utility CPS Energy has agreed to acquire Talens' gas-fired power generation capacity in Texas in a $785 million transaction, expected to close in the second quarter. The assets include Talen's 897 MW Barney Davis and 635 MW Nueces Bay gas-fired power plants, both situated in Corpus Christi, as well as its 178 MW gas-fired generation facility in Laredo.

Barney Davis power plant in ERCOT

In total, the deal secures an additional 1,710 MWs of power for the greater San Antonio community, expected to become "available as soon as this summer." Acquisition of these assets aligns with CPS generation plan which foresees the retirement of older units and the addition of a blend of gas, solar, wind, and energy storage.

"The investments we are making to purchase and improve the performance of these plants provide cost benefits when compared to building new assets, which means reliability now at a lower price for our community," said Rudy D. Garza, President & CEO of CPS Energy.

San Antonia-based CPS Energy plans to retire some 2,249 MW of older and inefficient dispatchable generation capacity before 2030. To fill the gap, the utility already added 730 MW of solar energy and 50 MW of energy storage to date, with an additional 500 MW energy storage RFP in the works.

The flexible gas-fired plants in Corpus Christi and Laredo are expected to be operational for the next 25 years, providing much-needed balancing power as the renewables build-out progresses. ■

Germany shuts 7 coal power plants over Easter, RWE and LEAG confirm

Seven coal-fired power stations in Germany have been permanently shut down over Easter, the plant owners RWE and LEAG confirmed. Some of these coal plants had been restarted to help utilities cope avert the risk of natural gas shortages over the winter period, as Germany has weaned itself off Russian gas in return for more costly LNG.

Five of the shuttered plans, including the Neurath and Niederaussem sites, are situated in the Rheinish mining district near Cologne, with RWE noting it will commission a total of 2,100 MW of lignite-fired capacity. Two other plant at Jänschwalde near Berlin were also closed after having been brought back from a grid stability reserve recently.

RWE's Neurath C lignite power unit

Now that the winter season has drawn to a close, the German grid operator BNetzA gave green light for the shut-downs as it does not expect them to impair security of power supply. The coal exit is instrumental for the German government to meet its climate targets.

In an effort to avert gas shortages during the energy crisis in the wake of Russia's invasion of Ukraine and halt in contractual gas deliveries to Europe, Germany delayed its nuclear exit and temporarily reopened some recently decommissioned coal power plants in 2022 and 2023. That move greatly increased the country's carbon footprint, with the regulator mandating the economy ministry to propose measures to offset these additional emissions.

Backup coal plants deemed necessary until March 2031

Despite the latest coal power plant closures, the regulator approved to retain several coal-fired power plants in reserve until the end of March 2031 as construction of new gas-fired units could be delayed. These coal plants would "only run rarely" if requested by the TSO, with BNetzA stressing the intention is still to have no coal-fired power dispatched on the market after 2030.

Several grid operators, including TransnetBW in the southwestern state of Baden-Württemberg, had urged the regulator to keep coal-fired power plants as a backup for longer than initially planted to ensure system stability. The ruling coalition intents to pull forward the coal exit date to 2030 for all of Germany, although state governments in the eastern part of the country voiced concerns about an earlier exit, or reject it outright.

To replace Germany's remaining coal power plants before the official end date in 2038, the government must design and implement market mechanism to incentivise new-builds of alternatives. Markus Krebber, CEO of Germany's largest utility, said a coal phase-out in 2030 is only feasible if the government supports the construction of "future-proof gas power plants." These flexible units should be gradually converted to run on hydrogen in the 2030s, he underlined. There must be clarity which plants should be built when, where and by whom," Krebber stressed, warning: "Otherwise, the coal exit will become very difficult." ■

Petronas studies storing CO2 emitted by JERA in Japan in Malaysia

Malaysia's state-owned oil and gas company Petronas and Japan's largest utility JERA are studying the feasibility of separating and capturing CO2 emitted by power plants in Japan, and then transporting it to Malaysia for storage. Petronas has expertise with carbon, capture and storage (CCS) and claims "Malaysia has an abundance of potentially suitable sites for underground CO2 storage."

The captured CO2 is predominantly meant to be stored in Malaysia's depleted gas fields and can also be used for enhanced oil recovery.

As Japan's largest LNG importer and power producer, JERA is testing to runs its coal-fired plants on clean-burning ammonia. Alternatively, the carbon emissions of the plants can be sequestrated, condensed and shipped abroad. Petronas is understood to receive compensation for storing CO2.

Both partners are examining the technicalities of post-combustion carbon capture in Japan, transportation methods and shipping/receiving conditions for cross-border CO2 transport, and storage of CO2 in Malaysia gas fields. Petronas is understood to receive compensation for storing CO2 emitted in Japan.

Moving forward, JERA expects the collaboration with Petronas can help build a global network for cross-border carbon transport and storage. ■

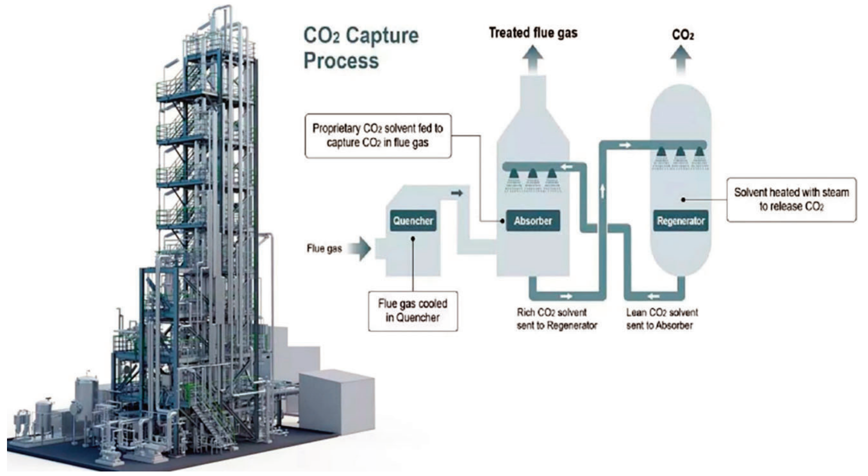
MHI and KEPCO to capture carbon emissions at Japanese power plant

Mitsubishi Heavy Industries (MHI) has agreed with Kansai Electric Power Co (KEPCO) to install a carbon capture pilot plant at Himeji No.2 power plant in Hyogo, Japan. The pilot plant will use flue gas from the turbine with a capacity to capture some 5 tons per day, once in operation in fiscal 2025.

By implementing Sigma Syncs (ΣSynX), it will be possible to monitor the operation status of the Himeji No.2 power plant at MHI Yokohama Building and other sites, and to automatically start and stop operations by remote control.

The next-generation CO2 capture technology, employed at the pilot project, has been jointly developed by MHI and ExxonMobil since 2022. The pilot is aimed at accelerating R&D and reduce cost to strengthen the technology's competitiveness. Going forward, ExxonMobil and MHI are considering retrofitting the technology at petrochemical plants they built in Baytown, Corpus Christi and Singapore.

CO2 solution are vital for MHI Group to achieve carbon neutrality by 2040 and the Japanese manufacturer strives to integrate diverse sources of carbon emissions with modes for carbon storage and utilization. Together with KEPCO, MHI Group has been KM CDR Process (Kansai Mitsubishi Carbon Dioxide Recovery Process) which has been delivered to 16 plants, and two more are under construction. The process adopts the KS-21 solvent, which offers superior regeneration efficiency and lower deterioration than the KS-1, and has been verified to reduce operating costs at low amine emissions. ■



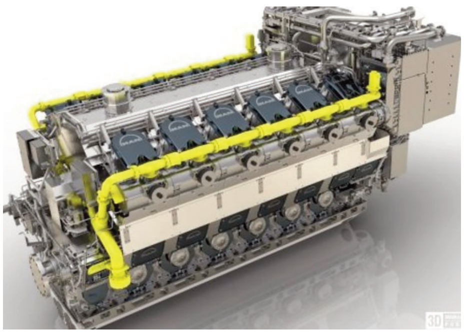
MAN 51/60DF engine clocks in 10 million operating hours

The MAN 51/60DF engine – used in shipping and power plant operation – has passed the milestone of 10 million operating hours. The dual-fuel engine comes in various power classes from 6.3 to 20.7 MW and has proved "extremely popular," the manufacturer said, with 310 engines currently in service – an increase of almost 100 units since 2022.

Capable to run on a wide variety of fuels including natural gas, biogas, bio-fuel, synthetic fuels, distillates and heavy fuel oil, the 51/60DF engine has been in MAN Energy Solutions' portfolio since 2009. Over the years it "has become a fixture in shipping and power-plant operation and stands for absolute reliability – even in high ambient temperatures," Stefan Eefting, head of MAN PrimeServ Germany said.

"Switching between the different fuels happens more or less at the touch of a button and is possible at any point between 0 and 100% load without any loss of power or frequency shift," he explained.

"Fuel flexibility is a must for modern engines," he stressed, noting that the 51/60DF engine in the future will also run on green synthetic fuels like methanol to comply with tougher emission requirements of World Bank and IMO and help decarbonise the energy and maritime sectors.



The 51/60DF engine is also available as a retrofit kit for 48/60 engines

The reliable engine achieved availability rates of up to 98%, as many of its core components show remarkably little wear even after extended operation, regardless of whether the engine has been running on heavy fuel oil or gas. The achieved maintenance intervals significantly exceeded the expected, planned schedule of 36,000 hours. ■

In-service tank inspections increase uptime

Houston-based technology firm Square Robot is carrying out a series of in-service tank inspection together with the power producer Tennessee Valley Authority (TVA). Three rapid inspections in three days were carried out at TVA's Marshall combined-cycle power plant in Kentucky, eliminating hundreds of hours of downtime and high-risk confined space entry work.

According to the TVA, an out-of-service API 653 inspection could command up to 30 days of project time per tank. Using its SR-1 submersible robot, Square Robot performed all three inspections in only three days while the tanks remained fully operational containing fuel oil. In-service works at the Marshal CCGT also avoided almost six tons of carbon dioxide (CO2) emissions typically required to take a fuel oil tank out of service for inspection.

The fourth and final robotic inspection under the program with TVA and the Electric Research Power Institute's (EPRI) will be for a 92-feet diameter fire water tank at the Magnolia Combined Cycle Plant in Mississippi. Once the program is completed, Square Robot will present its findings at the EPRI Incubatenergy Labs Demo Day. ■

Pertamina's Jawa-1 LNG-to-power project ready to run at full capacity

Indonesia's national energy company Pertamina has announced its PLTGU Jawa-1 power station is ready to run at full capacity after passing pre-commissioning tests in late March. The 1,760 MW plant, consisting of two equally-sized units, is equipped with a regasification system which allows it to handle LNG mostly sourced from BP's Tangguh field in West Papua.

Once operational, PLTGU Jawa-1 will be the largest integrated power plant in Southeast Asia. The project has been handled by Jawa Satu Power, a consortium of Pertamina New & Renewable Energy (40%) as well as the Japanese firms Marubeni (20%) and Sojitz (20%).

All electricity generated at the plant has been sold upfront to Indonesia's PLN under a long-term contract. Pertamina disclosed the second power plant unit (880 MW) has already been in commercial operation since December last year. The two-unit plant is powered by the latest generation of single-shaft combined cycle gas turbine technology and achieves up 60-65% thermal efficiency.

View of Pertamina's Jawa-1 PLTGU

"Existence of the Jawa-1 PLTGU is essential in the energy transition process where gas is environmentally friendly energy and the main bridge to realize the national energy mix as mandated by the President of the Republic of Indonesia," said Pertamina NRE's corporate secretary of Dicky Septriadi.

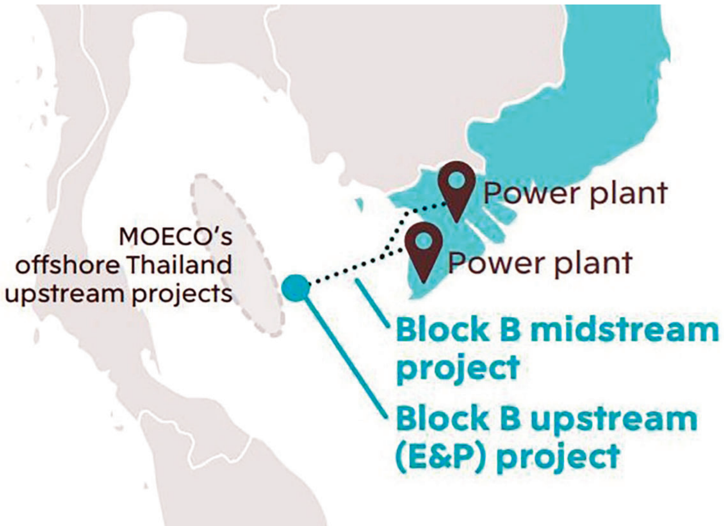
Fuel for the gas power plants are shipped as LNG from BP's Tangguh facility in Indonesia's Papua Barat province via the Jawa Satu FSRU. The 170,000-cbm Jawa Satu FSRU received its first commissioning cargo back in April 2021, meaning the fuel supply chain for the gas power plant is well established and fully functional. ■

Mitsui Oil takes FID on Vietnam gas upstream and power project

Mitsui Oil Exploration Co (MOECO) has made a final investment decision for the Block B Project, comprising an upstream gas pipeline and a pipeline to fuel a gas-fired power plant. Production capacity at the field off southern Vietnam is estimated to be 490 million cubic feet per day, with first gas expected by the end of 2026.

MOECO's partners in the project include the national oil and gas company PVN, PetroVietnam Exploration Production, PV Gas and the Thai national oil company PTT.

In addition to tapping a gas field in southern Vietnam, Block B Project also comprises the construction of a pipeline and related midstream infrastructure. MOECO's share of the development costs will be approximately $740 million, the Japanese company said in a statement.



The project is in line with Mitsui's strategy of investing in natural gas and LNG which are seen as "real solutions" for facilitating the global energy transition. The Block B Project will enhance the supply of gas fuel for cleaner-burning power plants. ■

NEWS NUDGES

TAQA develops industrial CHP for Aramco

Abu Dhabi National Energy Company (TAQA) together with JERA have entered into a power and steam purchase agreement with Saudi Aramco and TotalEnergies that forms the basis for a greenfield industrial cogeneration plant at the Amiral petrochemical complex in Jubail. The Amiral CHP plant will be developed by a special purpose entity owned by TAQA (51%) and JERA (49%) on a 25-year build, own, and operate basis extendable by five years.

Green NH3 made in Egypt

Saudi-listed ACWA Power is forging ahead with the first phase of a green hydrogen project in Egypt, aimed at producing 600,000 tonnes-per-year of ammonia (NH2) based on wind and solar power. Investment into phase 1 is anticipated to be in excess of $4 billion, with ACWA intending to scale up the project towards a future capacity of 2 million tonnes-per-year.

Wärtsilä launches Quantum2

Wärtsilä has launched Quantum2, a high-capacity battery energy storage designed for large-scale deployment. Fully tested pre-installed liquid-cooled IP67 modules, it requires no additional site work which minimises field construction for 2-6-hour storage projects.

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