



LNG exports from Egypt can resume even without Israeli gas; Eni claims

Italy's Eni prepares to restart LNG exports from its Damietta terminal in Egypt later in early December – seemingly unfazed by the halt in gas flows from Israel. Though acknowledging the Israel-Hamas conflict “evidently effects the regional balance,” Eni's head of global gas business, Cristian Signoretto said shipments will resume once Egypt's domestic demand is seasonally lower.

For most, excess gas supply in Egypt looks like a long way off: Rolling blackouts had to be extended in Cairo and other major Egyptian cities early last week due to acute fuel shortages at gas-fired power stations. Imports from neighbouring Israel have ground to a halt earlier this week, falling from 800 million cubic feet of gas per day (mmcf/d) just weeks after Chevron was mandated to shut down the Tamar field.

Chevron had been trying to honour some of its contract with Egypt by delivering gas from the Leviathan field instead – but by



Damietta LNG, some 60km west of Port Said

now flows have now fallen to zero.

Still, Eni's head of gas is convinced that the onset of cooler weather in Egypt is bound to bring down domestic gas and electricity demand substantially – enough to free up volumes. Exports of LNG should hence resume once these seasonal effects become

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Arbitrage for US-origin LNG cargoes to Asia closes despite lower offers

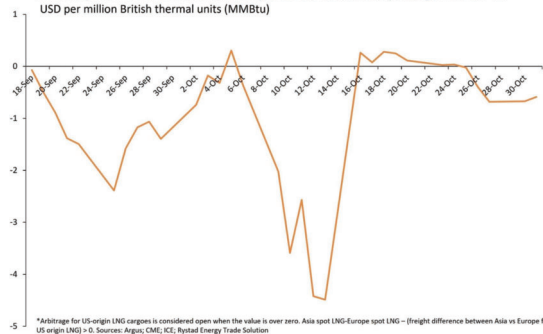
An arbitrage window for US LNG shipments to Asia has just closed in late October, prompting sellers to lower their offers to \$17.3/MMBtu. Japan's Tohoku Electric used the arbitrage opportunity and bought LNG for late December 2023 delivery, but most buyers were reluctant to come forward as rising nuclear power contribution reduces the need to dispatch gas-fired plants.

Nuclear power is on the rise both in Japan and South Korea: Kansai Electric plans to restart its 1.18 GW Ooi nuclear unit 4 in early November and to reach full capacity by 21 November, while 826 MW Mihama nuclear unit 3 is offline since October 25 for planned maintenance.

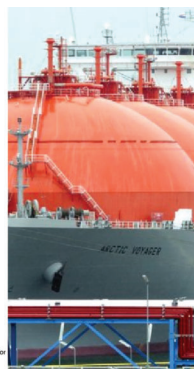
With the earlier restart of Takahama units 1 and 2, Kansai Electric has approximately 2.5 GW of nuclear power capacity available as of 1 November.

In South Korea, the 1 GW-Hanul unit 4 reached normal operating output on 29 October, following

Arbitrage for US LNG to Asia mainly closed after brief opening in week 42*
USD per million British thermal units (MMBtu)



*Arbitrage for US-origin LNG cargoes is considered open when the value is over zero. Asia spot LNG-Europe spot LNG – (freight difference between Asia vs Europe for US origin LNG) > 0. Sources: Argus, CME, ICE, Rystad Energy Trade Solution



maintenance which began on 16 September. “An additional 1 GW of available nuclear power capacity in South Korea could replace approximately 0.1 million tonnes of LNG per month,” Rystad analysts reckon.

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more pronounced, Signoretti said in a conference call on Eni's quarterly earnings.

In May, Eni offloaded a cargo produced at Damietta LNG into Snam's new regas terminal in Piombino, near Livorno. The Damietta facility produced and loaded its 500th cargo in February and since its restart in 2021, Damietta LNG facility exported 7.2 million tons of LNG. During 2022, Damietta produced and exported about 4 million tons of LNG – the largest volume in its near 20-year history – with around 60% of the total shipments delivered to Europe.

Capex in upstream projects at risk

Prolonged shutdown of the Tamar field

forces Israel to use gas from the Leviathan field to meet its own energy needs instead of selling it to Jordan and Egypt. Analysts warn there is considerable risk of losing around \$4 billion in capital investments for upstream projects during the next three years which would undermine the region's "significant exploratory success and the discovery of low-cost resources."

In 2025, the Tamar expansion project had been designated to get \$1.2 billion of investment and for Leviathan Phase 1 B, planned in 2026, another \$435 million of capex is at risk. The goal had been to set up a Floating Liquefied Natural Gas (FLNG) unit with a capacity of 4 to 5 million metric tonnes per annum (mtpa) as an

alternative to tapping into the European market.

The Leviathan field can produce up to 2.1 billion cubic feet per day (bcf/d) and its ramp-up potential is about 700 mmcf/d, according to Rystad estimates. Any delayed, or possibly derailed, upstream investments risk to not only the regional supply balance but could also put a promising FLNG project as another source of non-Russian supply for Europe off the table. Analysts account that Egypt had exported 3.7 million tonnes of LNG between October 2022 and January 2023, with the peak at just less than 1 million tonnes in December 2022 – roughly equal to Tamar's 33-day production shutdown at current rates. ■

British PM announces plans for annual oil & gas licensing rounds

The British Prime Minister Rishi Sunak has used the King Speech to announce a legal bill for annual North Sea oil and gas licensing rounds, meant to create certainty for the industry when transitioning to greener energy. In July, Sunak said over 100 new licences would be granted which he claims to be compliant with the government's environmental targets.

A new licensing round is intended to only be held if the UK is projected to import more oil and gas than it produces at home. "Domestic energy will play a crucial role in the transition to net zero," the PM said, adding the legislation would provide "clarity and certainty."

Deepening a policy divide with Labour as he seeks to hold a general election in late 2024, Sunak insisted the bill would protect jobs and bolster Britain's energy supply security by reducing its need to import oil, gas and electricity on volatile world markets.

Today, there are just under 300 active oil and gas fields in the North Sea, according to the trade body Offshore Energies UK, but

more than half of the them will have ceased production by 2030 – putting supply security at risk.

"Even when we've reached net-zero in 2050, a quarter of our energy will come from oil and gas," Sunak underlined. In fact, natural gas fuelled the lion's share, or 38.4% of Britain's electricity generated in 2022, followed by wind power with 24.6%, nuclear with 14.6% and bioenergy with 10.9%, according to the Department for

Energy Security and Net Zero.

In an apparent U-turn, Climate Change Committee (CCC) – the government's independent climate advisers – acknowledged oil and gas would play a "large part of our energy baseload" in future decades. The change of minds comes having factored in the effects of supply shock in the wake of Russia's invasion of Ukraine, as well as the escalation of the conflict in Israel. Previously, the CCC had said Britain would "continue to need some oil and gas" although this itself would "not justify the development of new North Sea fields."

New upstream ventures would have to meet net zero targets by 2050, hence there is a need for related carbon capture and storage (CCS) projects. Still, Greenpeace vowed to fight the new bill for annual licenses in court. ■



Shell's Nelson platform in the UK North Sea

Continued from page 1

Mild autumn temperatures and healthy nuclear contributed made buyers in most Asian countries refrain from buying LNG – although the arbitrage for US-origin LNG was open from 16-23 October. Arbitrage for LNG cargoes from the United States is considered open when the value is over zero (see graph).

Eager to keep selling cargoes after the arbitrage closed, sellers lowered their offers.

So, for the first time since the start of front-month Asian spot LNG index pricing for December delivery on 16 October, the LNG price differential in Asia between December 2023 and January 2024 is now in backwardation by approximately \$0.84 per MMBtu as of 31 October. But analysts pointed out this is mainly due to the front-month price having already factored in half of the total 22-pricing days for the index. ■

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South Africa accelerates 3 GW of gas power projects; minister says

South Africa is speeding up plans for 3 gigawatt of gas-fired power generation capacity to avoid daily cuts in electricity supply that are hurting the economy, electricity minister Kgosientsho Ramakgopa said. Shortages are caused by regular faults at Eskom's ageing coal-fired plants, with officials estimating up to 6 GW of new capacity is needed to end rolling blackouts.

Build-out plans include a 2 GW mobile plant – partly based on a floating power barges offshore – and a 1 GW plant near Coega, with the minister disclosing the government was at the procurement stage for these two projects. In May, South Africa's Department of Mineral Resources and Energy launched a Request for Proposals (RFP) for 2,600 MW of new capacity. In total, ministry seeks to procure 11,813 MW of electricity from various power sources including renewable energy, storage, gas and coal.

Discord over LNG-fuelled power

Gas is favoured over coal as a dispatchable power source: "One of the things receiving priority is around the 3,000 megawatts of gas. As you know gas, from an emissions standpoint, is a step down compared to coal, so it's important we accelerate that,"

Ramakgopa told local reporters.

Critics, however, voice concerns about the cost of LNG-fuelled emergency power while proponents view gas-fuelled power as the fastest and most cost-effective pathway to decarbonisation given that today coal-fired plants still account for over 84% of South Africa's total CO2 emissions.

Initial plans for a 3 GW gas-fired power plant in Richards Bay East were facing stiff opposition by environmentalists who call for wind and solar power projects instead. The minister was hence quick to point out that South Africa anticipates more than 5.5 GW



Eskom's Camden power plant, situated in the Eastern Transvaal.

of new renewable energy projects to start operation by 2026.

Nuclear is favoured as another emissions-free energy source. The government is taking steps to extend to life of its 40-year-old 1.94 GW Koeberg nuclear power plant by 20 years beyond its scheduled shutdown in 2024. ■

Arizona utility turns to H2-ready gas turbines, RES and battery storage

Arizona Public Service (APS), providing electricity for nearly 1.2 million customers in the state, seeks to add substantial amounts of renewable energy sources over the next five years, backed up by hydrogen-ready gas turbines and battery storage. In its 2023, Integrated Resource Plan (IRP), the utility says H2-ready gas turbines would complement renewables and storage in a least-cost portfolio.

The turn to clean energy sources in the IRP has been filed with the Arizona Corporation Commission, the state's regulator for the electric power industry. But in its filing, the utility also stated it will refrain from retiring the Four Corners power plant as early as 2027, citing reliability concerns.

Even as renewables and energy storage are added, APS claims it will need dispatchable gas-fired power sources capable of "re-

liably meeting demand throughout the overnight period," especially given the upcoming retirement of the Cholla power plant in April 2025 and the looming exit from another large coal-fired power station – Four Corners.

Opting against early coal exit

Initially, APS had planned to exit the 1,500 MW Four Corners as early as 2027. But any early coal exit scenario would be "heavily dependent" on the availability of sufficient gas-fired power sources and the time required for adding new capacity would leave the grid strained for too long.

In view of the upcoming retirement of the coal-fired 1,020 MW Cholla power plant in April 2025, Arizona Public Service has hence chosen to keep the Four Corners plant operational until 2031.

"[We] cannot responsibly support the early exit from Four Corners due to reliability concerns associated with the transition to newer, nascent technologies, as well as the lack of sufficient excess capacity resources in the Western United States," Arizona Public Service writes in the regulatory filing.

Once the two large coal power plant will be offstream, Arizona Public Service expects to face "significant gaps" especially for reliable summertime capacity. Fast-start, H2-ready gas-fired power sources could be co-located at existing thermal power stations, the utility suggests, as reusing infrastructure would save cost and speed up commissioning.

Energy demand is forecast to increase substantially over the coming years: Currently, APS customers use electricity of about 9,400 MW installed capacity but will need 11,350 MW by 2027 and up to 13,000 MW by 2031. Arizona Public Service is wary that peak power demand could grow by 40% over that period of time. ■



Four Corners power station will not be shuttered early

Petronas and TNB to develop CCS for gas-fired power plants

Malaysia's state oil firm Petronas and the utility Tenaga Nasional Bhd (TNB) have agreed to explore carbon capture and storage (CCS) technology with a view to retrofitting gas-fired power plants. Though Malaysia aims to reach Net Zero carbon emissions by 2050, domestically-produced gas is deemed critical in the country's energy transition.

Flexible gas-fired plants will help integrate fluctuating electricity supply from renewables and guarantee a stable baseload power source. Retrofitting gas-fired power units with CCS hence helps TNB to extend the life-time of these assets.

The Memorandum of Understanding to capture carbon from fossil power plant, "resonates with our commitment to environmental sustainability through the exploration of CCS technology and aligning with Malaysia's National Energy Transition Roadmap (NETR)," said TNB's chief executive Dato' Seri Ir. Baharin Din. His counterpart at Petronas, Tengku Tan Sri Muhammad Taufik called the energy system a "systemic challenge" which requires

close industry cooperation to achieve the aspired carbon neutrality.

Developing H2-ready power sources

Apart from post-combustion carbon capture, TNB is also looking to use cleaner fuel sources – notably hydrogen: The Malay power producer has partnered with Widad Business Group to develop a 2.1 GW combined-cycle gas power station at Kapar, Selangor, an estimated cost of 9.5 billion Malaysian Ringgit (\$2 billion).

The CCGT will be capable to co-fire hydrogen when entering commercial operations in early 2031.

H2-ready Gas power projects like Kapar will help TNB halve its reliance on coal generation by 2035, and slash its emission intensity by 35%. Natural gas is fuelling 41% of Malaysia's of installed power generation capacity at 15.8 GW, or 35% of its electricity output of around 60 TWh.



TNB's Prai power station at the coast of Penang

Electricity grids could be the weak link in the clean energy transition

There are worrying signs that grids are not keeping pace with the rapid growth of key clean energy technologies such as solar, wind, electric cars and heat pumps, the International Energy Agency (IEA) warns. Major changes to how grids operate are essential while annual investment needs to double to more than \$600 billion a year by 2030.

In recent years, investment in power grids stayed broadly stagnant. But achieving all national climate goals will require adding or replacing 80 million kilometres of power lines by 2040 – an amount equal to the entire existing global grid, reads the IEA's latest report, entitled 'Electricity Grids and Secure Energy Transitions'.

At least 3,000 gigawatts (GW) of renewable power projects, of which 1,500 GW are in advanced stages, are waiting in grid connection queues – equivalent to five times

the amount of solar PV and wind capacity added in 2022. "This shows grids are becoming a bottleneck for transitions to net zero emissions," analysts pointed out.

In a scenario in which countries' national energy goals are met on time and in full, wind and solar PV account for more than 80% of the rise in power generation capacity over the next 20 years, compared with less than 40% currently. In the IEA's Net Zero Emission by 2050 Scenario, wind and solar even account for almost

90% of the increase.

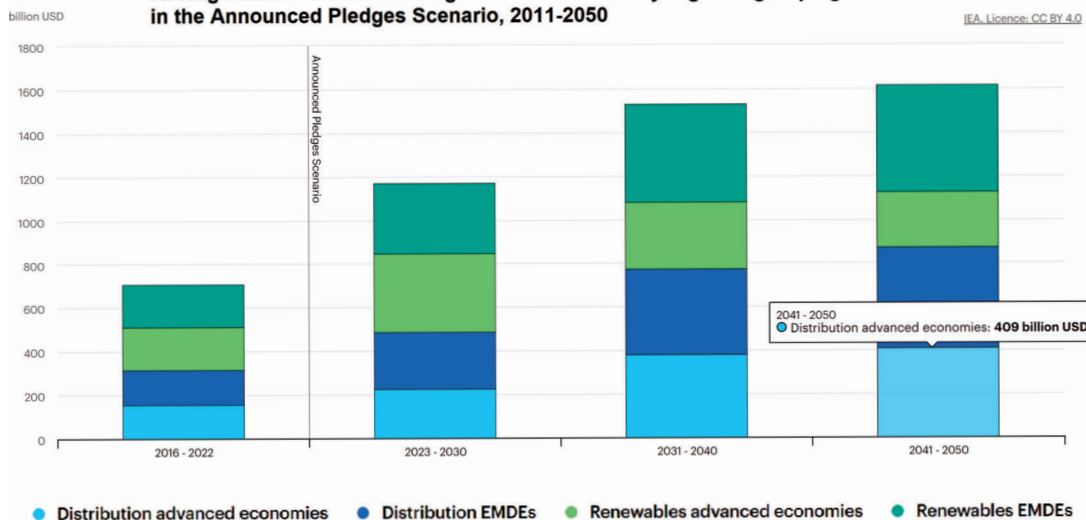
Rapid electrification requires grid build-out

To meet climate goals, the world's electricity use needs to grow 20% faster in the next decade than it did in the previous one. Expanded grids are critical to facilitate such levels of growth as the world deploys more electric vehicles, installs more electric heating and cooling systems, and scales up hydrogen production using electrolysis.

Delays in grid investment and regulatory reforms would substantially slow down the uptake of renewables and lead to higher fossil fuel use. In the Grid Delay Case, global gas imports are over 80 billion cubic metres (bcm) a year higher after 2030 than in a scenario aligned with national climate targets – and coal imports nearly 50 million tonnes higher, incurring substantial costs.

Delayed grid development also increases the risk that economically damaging power plant outages would multiply. Today, such outages already cost around US\$100 billion a year, or 0.1% of global GDP.

Average annual investment in grids & renewables by regional grouping in the Announced Pledges Scenario, 2011-2050



UK energy price cap to stay above current level until end-2024

Disruptions at the Finnish Balticconnector and reduced LNG exports from Egypt have pushed up forecasts for the UK's 2024 Default Tariff Cap by 5-6%, or between £91 and £110. Though the Gaza conflict is not directly impacting Britain, suspicion that 'outside activity' had damaged the Balticconnector raises fears that similar damage may occur elsewhere, increasing energy prices.

Cornwall Energy' predictions place a typical dual fuel consumer's January energy bill at £1,923 per year, with a small rise to £1,929 in April 2024.

The Default Tariff Cap, better known as the energy price cap, is based on an average household's gas and electricity use, pegged at 2,700 kWh per annum for electricity and 11,500 kWh per annum for gas. Initially, that cap had looked likely to fall below the current £1,834 typical bill rate next year due to a fall in wholesale gas prices, but ramifications of the Israel-Hamas conflict and fears of sabotage at European gas pipeline infrastructure keep the cap elevated.

"The jump in price cap predictions since September has once again highlighted the vulnerability of UK energy prices – and customer bills – to geopolitical events," said Dr Craig

Lowrey, Principal Consultant at Cornwall Insight. In his view, the government needs to proactively limit the impact of geopolitical events on the UK energy markets, rather than just reacting to events as they occur.

"Stop-gap measures such as social tariffs and one-off payments are helpful, but they

are not a long-term solution," he stressed, suggesting the UK should rely more on sustainable, domestically sourced energy instead. Reducing the reliance on gas and electricity imports helps insulated the country against supply shocks and helps stabilise prices. ■



QUARTERLY	New TDCV	Q1 2024 CI Forecast	Q2 2024 CI Forecast	Q3 2024 CI Forecast	Q4 2024 CI Forecast
Electricity	2,700 kWh	£961.26	£960.61	£928.87	£955.73
Gas	11,500 kWh	£962.08	£968.48	£950.79	£961.08
TOTAL		£1,923.33	£1,929.09	£1,879.66	£1,916.81

German gov' approves €5.5bn subsidy to cushion rise of grid fees

The German government has greenlit €5.5 billion to go towards grid fees in 2024 in an effort to dampen the impact of rising electricity prices on consumers. Monies from the Economic Stabilisation Fund will be used to help finance the grid fee charges which TSO want to increase to meet high costs for redispatch measures.

Redispatch costs are incurred when powerlines connecting the windy north and the industrial south become congested, hence not all available electricity can be transported. Suppliers who bought wind power for customers in the south hence cannot receive

that electricity, putting industry and household at risk of power shortages. To avoid that, TSO are calling on peaking power plants to quickly ramp up to make up for the wind power that cannot reach the south.

Extra costs for consumers due to re-dispatch measures are incurred by TSOs having to compensate wind farms for telling them to limit production at times of grid congestion. Conventional power stations in south Germany which are called on to produce extra power, do so at a higher cost than the market price.

In 2015, re-dispatch measures in Germany cost an estimated 402.5

million euros, according to transmission grid operators' estimates. Jochen Homann, president of the Federal Network Agency, had warned at the time the annual figure could rise to €1 billion by 2020.

Grid fees may soar 17% in Bavaria

Looking ahead, analysts expect distribution grid fees to rise by 11% on average in 2024 – despite the government's financial support. This would raise costs for an average household by 47 euros per year, according to the price comparison site check24.

Price rises will be higher in the previously comparatively cheap southern states. In Bavaria, grid fees are expected to rise 17% next year, with consumers paying roughly 66 euros more compared to 2023, analysts calculated. ■



Giga-scale PEM electrolyser factory opens in Berlin

Air Liquide and Siemens Energy have opened a new electrolyser production facility in Berlin today, built at a cost of around €30 million. By 2025, proton exchange membrane (PEM) electrolysers with at least three gigawatts (GW) of electrolysis capacity per year are to be brought to market from there to help ramp-up the hydrogen economy.

For hydrogen to become attractive as a fuel for power generation and industry, it must be available in large quantities and at competitive prices. This requires serial production of cost-effective and scalable electrolysers.

Starting with an annual production capacity of 1 GW, the electrolyser factory at Berlin Huttenstraße is expected to be ramped up to at least three gigawatts by 2025 with potential for more. With 3 GW electrolysis capacity, an average of 300,000 metric tons of green hydrogen can be produced per year – enough to avoid fossil fuel emissions equivalent of a city like Aachen.

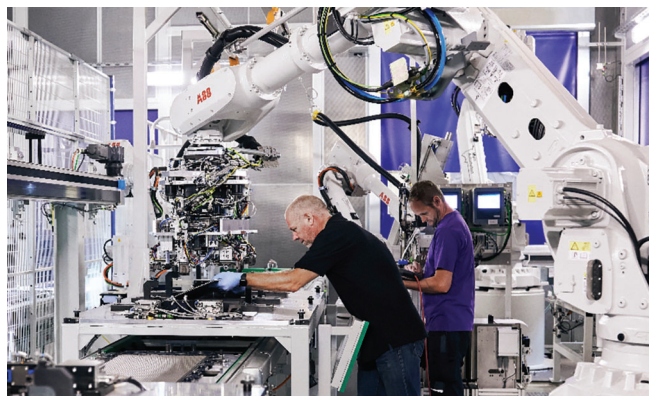
PEM electrolysers cheaper to build

The new factory will supply stacks – the heart of electrolysers – based on proton exchange membrane (PEM) technology. Compared to other hydrogen technologies, PEM electrolysers can bring gigawatt capacities to market with lower material, manpower

and space requirements, Air Liquide and Siemens Energy claim. Once produced, the stacks will be assembled closer to the project sites.

"Mass production of industrial scale electrolysers is essential to making competitive renewable hydrogen a reality," Air Liquide CEO François Jackow said, specifying: "This state-of-the-art technology will soon be operated at the Trailblazer electrolyser in Oberhausen, with a major scale up-coming for the Normand'Hy electrolyser project."

For Normand'Hy, Air Liquide aims to build an electrolyser of at least 200 MW near Port-Jérôme, northern France before 2035, while the smaller, 20 MW electrolyser in Oberhausen is meant to already start operation



Quality control of PEM electrolysers

before the end of this year.

The Normand'Hy project will be one of the first to be supplied with electrolysers built in Berlin as will be the Trailblazer in Oberhausen. In addition, Siemens Energy is working on other large-scale project such as in Kassø, Denmark, or the FlagshipONE venture in Sweden, which will provide hydrogen for the synthesis of efuels for shipping. ■

MHI posts 55.4% jump in order intake on strong demand for CCGTs

Mitsubishi Heavy Industries has announced a 55.4% year-on-year rise in order intake to ¥3,137.0 billion in the first half of this year on strong demand for installations and after-sale services for combined-cycle gas turbine (CCGT) power plants intended to run on clean fuels. Better CCGT margins offset a one-time charge in aero engines associated with the PW1100G-JM engine.

Aero engine maker Pratt & Whitney had raised alarm in July that 1,200 of its PW110G-JM engines will require off-wind inspections due to a "rare conditions" in power metal used to make certain geared turbofan engine parts. To mitigate safety hazards, a sizable number of Airbus A320neo passenger planes, on which these turbofan engines have been installed, now require new engines.

Still, MHI's revenue in the energy segment increased by 8.1% to ¥777.2 billion, pushing up profits by 15.7% to ¥35.3 billion in the first half-year ending September 30.

"I am pleased with our performance during the first half of this fiscal year, during which we realized record highs in order intake, revenue, and profit," Hisato Kozawa, MHI chief financial officer commented. Especially strong results were achieved for CCGTs, logistic systems and in the defense & space segment.

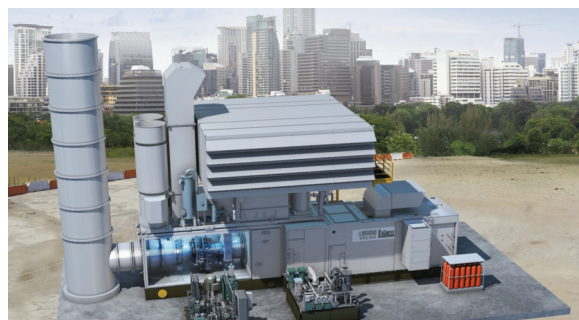
Looking at profitability, the CFO underlined that "topline growth, price optimization, project margin improvements and the depreciation of the yen more than offset negative impact from the PW1100G-JM engine project and rising domestic labour and energy costs." Though MHI is on track to achieve its medium-term goals, Kozawa urged employees to

"avoid overconfidence and maintain vigilance (...) to ensure we are delivering quality products to customers on time and within budget.

Turning to ammonia

Catering to utilities' drive to decarbonise, MHI is intensifying efforts to co-fire thermal power plants with clean-burning ammonia. Technical studies on that matter are about to start in cooperation with PLN Nusantara Power, part of Indonesia's state energy firm Persero. Tests at 1,233 MW Muara Karang combined-cycle gas power plant will examine hydrogen combustion in a M701F Series gas turbine currently in operation, as well as ammonia co-firing in a gas-fuelled boiler.

To clean up coal combustion, MHI is seeking to co-fire ammonia at the 4,025-MW Suralaya power station. Efforts to run some units of the coal-fired plant partly on ammonia is meant to be conducted jointly with Mitsubishi and Nippon Koei. ■



Render of the LM6000VELOX package

Jenbacher H2 engine to power RAG's cogeneration plant by spring 2024

RAG Austria has selected INNIO's Jenbacher hydrogen-ready engines to produce green electricity and heat at its cogeneration plant in Gampern. Commissioning of the world's first 100% hydrogen underground storage allows for up to 4.2 GW of surplus electricity from wind and solar produced in summer to be kept ready for winter in the form of green hydrogen.

Commissioning of the Jenbacher hydrogen CHP plant in the 1 MW range is scheduled for spring 2024.

During the subsequent winter, electricity can then be generated on-demand from the green hydrogen reserves, and the waste heat can be used for heating purposes. In this project, INNIO and RAG focus on seamless coordination between the generation, conversion, storage, and – most notably – supply of green energy.



RAG's storage in Upper Austria

"In Gampern, we are demonstrating what can and must be done to manage the energy transition by securing a reliable supply of green energy throughout the year," said Markus Mitteregger, chief executive RAG Austria AG. In his view, hydrogen cogeneration plants are key for the entire hydrogen ramp-up. "Flexible, quick-start CHP plants can not only generate electricity as needed, but also produce the heat that is so important in winter. This significantly improves efficiency while also facilitating the heating transition," he explained.

His counterpart at INNIO Group, Dr. Olaf Berlien singled out the manufacturer's hydrogen technology as "foundational for energy security in the age of volatile renewables." The Jenbacher-based manufacturer

already helps businesses and communities around the world to become carbon-neutral; whereby "hydrogen-ready decentralized energy solutions make our energy supply future-proof." ■

Barry Unit 8 onstream

Alabama Power's Plant Barry Unit 8 is operating since the start of this month, serving customers across the state. The combined-cycle gas power unit, driven by a Mitsubishi Power JAC gas turbine, can generate up to 772 megawatt and combined with other units at the site, brings Plant Barry's total capacity to 3,246 MW.

With the new unit, Plant Barry is now largest generating facility in Alabama Power's system. The combined-cycle unit is long-term investment as Alabama Power transforms the way it affordably and reliably powers the state.

"Barry 8 uses the most advanced and efficient technology available to generate electricity from natural gas," said Brandon Dillard, Alabama Power senior vice president and senior production officer.

Construction of Barry 8 started in 2021 following approval by state regulators. In all, the construction team devoted more than two million workhours to the new unit.

Annual property taxes from Barry 8 are expected to be approximately \$4 million. Apart from supporting state revenues since its first unit began operation in 1954, the employees of Plant Barry supported the Mobile area community for decades. Since 2012 alone, plant employees contributed more than \$800,000 and provided more than 66,000 hours of their personal time to help local non-profits and community causes. ■



Barry Unit 8 in Mobile County, AL

GE secures two H-Class equipment orders from EnBW in Germany

Germany's regional utility EnBW has awarded GE Vernova two orders for H-Class power gen equipment for combined heat and power (CHP) stations in Heilbronn and Altbach near Stuttgart. The two CHP projects, with nearly 1,340 MW capacity combined, will replace existing coal-fired plants with more efficient gas-fired generation and are due operational by the end of 2026.

The orders include the equipment, construction of the plants as well as software solutions, maintenance and services for ten years. GE will lead a consortium for the projects, notably the EPC companies Bonatti and Sener. EnBW on Monday started construction at the Altbach site.

Each of the two 680 MW power plants will replace ageing coal-fired units and the

combined-cycle equipment will empower EnBW for up to 100% hydrogen combustion in the 2030s. Switching from coal to gas combustion alone can reduce carbon emissions by as much 60% and lower NOx and Sox emission substantially, however, the switch to full hydrogen combustion hinges on sufficient availability of the clean fuel at an affordable price.

The efficient CHPs at Heilbronn and Altbach/Deizisau are expected to deliver in total some 1,340 MW to the grid – the equivalent needed to power some 2.4 million German homes, – as well as steam for district heating for citizens, commerce and industry of Heilbronn and the larger Stuttgart area.

In terms of equipment, each cogeneration plant will be powered by a GE 9HA.01 gas turbine, an STF-D650 steam turbine, a W88 generator and a triple pressure with reheat HRSG. ■



Render of Altbach CHP for which ground was broken on Monday

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