Gas to Power Journal
Peakload Power and Energy Storage

Focus on cost of CCS vs clean fuels

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US awards nearly $900m for CCS retrofits of gas and coal power plants

The US Energy Department will award up to $890 million in funding to demonstrate the viability of post-combustion carbon capture (CCS) at gas- and coal-fired power plants in California, Texas and North Dakota. Project Tundra, projected to capture some 4 million tons of CO2 from Minnkota's lignite-fired Milton R. Young Station in North Dakota, already got $350 million.

Minnkota's Young Station, the site of Project Tundra

President Joe Biden deems CCS vital to mitigate climate change and the DOE said the selected projects could potentially prevent some 7.75 million metric tons a year of CO_2 of being released from combusting thermal coal and natural gas for power generation. Critics dismiss CCS retrofits as uneconomic and extending the reliance on fossil fuels.

FID on Project Tundra in mid-2024

Senator Kevin Cramer, a Republican, hailed Project Tundra as a "major feather in the cap for North Dakota's innovative energy system, keeping miners on the job while putting clean, reliable electricity on the grid." Developed on behalf of Minnkota Power Coop, the project is carried out by TC Energy, Mitsubishi Heavy Industries and Kiewit. Completion of engineering and design work on the carbon capture facility is scheduled for spring 2024, followed by a final decision on whether to move forward with the project in the middle of next year.

The CO_2 captured through Project Tundra from the Young Station will be permanently stored in saline geologic formations

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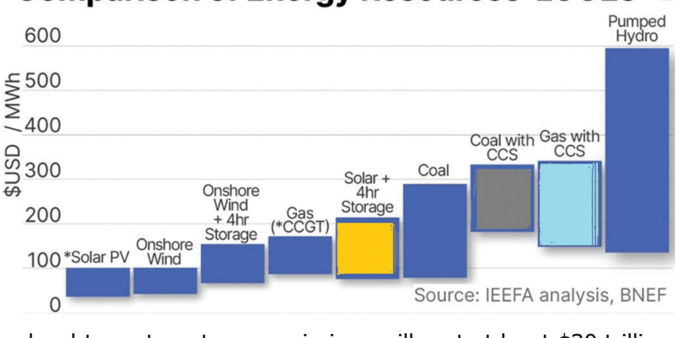
CCS technology found not yet market-ready, excessively expensive

Market readiness of carbon capture and storage (CCS) has been questioned by Oxford University's Smith School of Enterprise and the Environment as most facilities can remove only up to 50% of emissions. Moreover, a CCS-centric pathway to achieve net zero by 2050 could cost $1 trillion a year more than a route based on renewables, energy efficiency and electrification.

Comparison of Energy Resources' LCOEs



Entitled, 'Assessing the relative costs of high-CCS and low-CCS pathways to 1.5 degrees', the report looks at fossil power generation with carbon capture over the past 40 years. Though oil and gas producing countries put forwards projects to store carbon in depleted fields, researchers found that applying CCS throughout the economy – rather than in just a few hard-to-abate sectors, "makes little sense from a financial perspective."

From 2021 to 2050, taking a low-CCS pathway to net zero emissions will cost at least $30 trillion less than taking a high-CCS route – saving approximately a trillion dollars per year. Still, carbon capture is still necessary for essential use cases,

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AGENDA

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beneath and surrounding the power plant. Along with a second permitted storage facility near Center, North Dakota, the project has the ability to store up to 222 million metric tons of CO2 in North Dakota.

Other projects to receive Bipartisan Infrastructure Law funding include a CCS retrofit for the 896 MW gas-fired Baytown Energy Center in Texas. Adding post- combustion CCS equipment to this facility will reduce CO2 emissions intensity of two of its three combustion turbines at a design capture rate of 95%, resulting in low CO2 steam and electricity for chemicals manufacturing at the adjacent Covestro factory as well as power for the electric grid.

Another selected CCS project is the one at the550 MW gas-fired Sutter Energy Center gas plant in Yurba City, California. The 18-month pilot, scheduled to run through 2024, will inform the implementation of CCS at Sutter and provide a model for reducing carbon emissions at existing power plants by at least 95%, according to Calpine. ■

First CO2 tanker ordered by Schulte for Northern Lights

Hamburg-based shipowner Bernhard Schulte has ordered its first CO2 tanker from Dalian shipyard in China, planned for delivery in 2026 and committed to a long-term time charter with Norway's Northern Lights. Owned by Equinor, Shell and TotalEnergies, Northern Lights is developing the world's first open source infrastructure to transport CO2 from industrial emitters in Europe with operations scheduled to start in 2024.

The sequestrated and liquefied CO2 will be transported by ship to a receiving terminal at Øygarden, west of the Norwegian costal town Bergen, from where it will be transported by pipeline to a geological reservoir 2,600 meters under the seabed for permanent storage in.

The Northern Lights JV has already ordered three CO2 tanker, two already under construction at Dalian shipyard and another ordered in September this year. Schulte's first CO2 tanker will be the fourth in line as the company now enters the liquid carbon business.

All four ships are sister vessels, with the same design and a cargo capacity of 7,500 cubic meters. Custom-built for transportation of liquefied CO2, these ships will transport CO2 from Northern Lights' customers across northwest Europe to Øygarden for permanent geological storage. The primary fuel for these ships will be LNG.

"CCS is a safe and efficient way to handle emissions and it is critical to meet climate targets," said Børre Jacobsen, managing director of Northern Lights.

Onsite power plants at Øygarden are driven by GE gas turbines and the US manufacturer is working with Northern Lights on compatible CO2 transfer systems to reduce emissions from these power stations. In collaboration with Svante, GE is developing sorbents to capture carbon from gas-fuelled power generators through retrofits. ■

Construction of the CO2 tanker in China

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but not as a means to continue business-as-usual fossil fuel use, especially in the power generation sector.

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Cost of CCS unlikely to fall

Renewables are cheaper than unabated fossil fuels and technological advances will make wind and solar increase their cost advantages even further in the future. "Relying on high levels of CCS as a blanket solution to facilitate the ongoing use of fossil fuels would be hugely damaging," said Rupert Way, author of the study. "Any hopes that the cost of CCS will decline in a similar way to renewable technologies like solar and batteries appear misplaced."

Institute for Energy Economics and Financial Analysis (IEEFA) has similar concerns: Retrofitting thermal power plants with carbon capture and storage (CCS) inflates generating costs by at least 1.5 to 2 times above alternatives, analysts warn. Applying post-combustion CCS in Australia's National Electricity Market (NEM), where coal and gas makes up 70% of regional electricity output, would increase wholesale prices by over 95%.

The Australia case study tries to quantify the real cost of post-combustion CCS: Wholesale prices averaged between A$75 and A$95 per MWh in Australia's National Electricity Market (NEM) over the past decade, where coal and gas accounts for over two thirds of regional electricity output. If funded through electricity prices, applying CCS is expected to increase these prices by A$100 to A$130 per MWh, or 95% to 175%.

Of the two CCS retrofits projects implemented so far, the Petra Nova project in the US has since suspended operation and both projects had performed well below target capture rates of 90%. Moreover, no new fossil-fuelled power plant has been built with post-combustion CCS installed and operating at a commercial scale. Analysts hence suggest public funds should be used for "more technically sound options." ■

Carlton Power works towards FID on three H2 schemes in early 2024

UK energy infrastructure developer Carlton Power now aims to take a Financial Investment Decisions (FID) for its three green hydrogen projects early next year, as the ventures were selected for state support. Carlton secured contracts for each project – totalling 55 MW of capacity and an investment of about £100 million, each with planning consent.

All three – the 200 MW Trafford Green Hydrogen scheme, the 30 MW Barrow Green Hydrogen scheme and the 10 MW Langage Green Hydrogen hub – were awarded revenue support in the government's first hydrogen allocation round (HAR1). In total, 11 projects were selected which had agreed at a weighted average strike price of £241/MW, the government disclosed.

Carlton Power said its three hydrogen projects will replace about 215 GW of natural gas and should reduce carbon emissions by some 40,000 tonnes per annum from 2026.

Render of Barrow Green Hydrogen

The 30 MW venture in Cumbria will supply hydrogen to Kimberly-Clark's factory at Barrow-in-Furness and reduce the manufacturer's reliance on gas by up to 30%. The 200 MW project is situated within Carlton's Trafford Low Carbon Energy Park in greater Manchester, with the first phase consisting of 15 MW. Another 10 MW of green hydrogen production capacity will be developed together with Langage to the east of Plymouth.

To finance, build and operate the three projects, Carlton Power is working with the investment manager Schroder Greencoat. The joint venture, announced in May 2023, aims to build a hydrogen project portfolio in the UK of 500 MW by 2030. ■

NEWS NUDGES

JERA helps Persero enhance clean fuels, CCUS

Japan's largest LNG importer and power producer JERA has agreed to collaborate with PT Pertamina (Persero) to enhance the transport of LNG and hydrogen/ammonia in Indonesia, notably through decentralised receiving terminals. The two parties also consider creating new businesses related to CCUS for industry and power generators.

Saipem, Valmet to decarbonise industries

By combining Saipem's CO2 management technologies with Valmet's flue gas treatment units, the two companies seek to help decarbonise hard-to-abate industries and decentralised fossil power gen units. The Italian and Finish companies agreed to cooperate to bring flexible options for their customers' existing and new facilities.

TES launches $4bn hydrogen project

TES Canada has announced Project Maurice, a $4 billion project in Quebec, consisting of the construction of an electrolyser and renewable power assets. Upon its commissioning in 2028, the project will produce 70,000 tonnes of green hydrogen exclusively dedicated to Quebec end users.

Eleven winners of first UK hydrogen allocation round get over £2 billion

Eleven projects, totalling 125 MW capacity, were selected by the British government in the first hydrogen allocation round (HAR1) and will receive over £2 billion (around $2.5 billion) of revenue support. The successful projects were agreed at a weighted average strike price of £241/MW, though the subsidy will vary relative to changes in the reference (natural gas) price.

Of the 17 projects that entered final negotiations, two projects withdrew and 15 projects, totalling 243 MW of capacity, submitted Best and Final Offers. Of these, four were not successful, the government revealed.

First projects onstream from 2025

Funding from the HAR1 scheme will start to be paid once the 11 selected projects become operational, with the first ones anticipated from 2025. The government stress it had conducted a robust allocation process to ensure only deliverable projects that represent value for money are awarded contracts.

Apart from state support, the 11 projects will see £413 million of private capital being invested upfront between 2024 and 2026 which is hoped to create some 760 direct jobs during construction and operation. Further millions will have to be spnt by offtakers in the heavy industry and transport sectors to convert their operations to hydrogen.

Whitehall hopes HAR1 will help meet the 2025 goal of 1GW of electrolytic hydrogen production capacity. By 2030, the government aims for up to 10 GW of low carbon hydrogen production capacity, with at least half from electrolytic systems. "If realised, this could unlock up to £11 billion of private investment and support more than 12,000 jobs by 2030," government analysts noted.

To realise its ambitions, the government launched the second hydrogen allocation round (HAR2) with an aim to support up to 875MW capacity. ■

Sojitz and Kyushu Electric to supply Japan with green NH3 made in India

Sembcorp partners Sojitz and Kyushu Electric have agreed to pursue opportunities to produce green ammonia (NH3) in India for export to Japan. Under the government's 'Transition Roadmap for the Power Sector', Japan aims to import 3 million tons of ammonia as a clean-burning fuel by 2030, with demand forecast to soar to 30 million tonnes by 2050.

Subject to final supply arrangement, the parties will take FID on constructing green ammonia production sites in India, with Sembcorp as lead developer.

Importing green fuels

Japanese utilities are keen to import green fuels from far afield, including North America. Tokyo Gas, Osaka Gas and Toho Gas – and Mitsubishi are evaluating a project to produce 130,000 tonnes of e-methane in the United States per year and liquefy it at Sempra's Cameron LNG terminal in Louisiana for export to Japan. The plan is to produce or procure green H2 and synthesise it to e-methane – a clean fuel for power generation.

The proposed project would meet many objectives of a joint cooperation agreement between the U.S. Department of Energy (DoE) and Japan's Ministry of Economy, Trade and Industry (METI) in the field of carbon capture, utilization and storage, conversion and recycling, and CO2 removal. Developers are hence hoping for some state support, should the policy frameworks recognize e-methane as a carbon-neutral fuel.

To facilitate ammonia imports, the Japanese technology conglomerate IHI is looking into converting LNG receiving terminals near gas-fired power plants into ammonia-based facilities. First LNG terminals are meant to be modified in the second half of this decade, as JERA is striving to use ammonia as a carbon-neutral fuel for boilers and turbines at its fossil power stations. To that end, IHI agreed with GE to develop gas turbines running on ammonia.

Small-volume ammonia co-firing is already underway at JERA's Hekinan thermal power Unit 5, where two of the 48 burners have been replaced with test burners to examine the effects of different materials on hydrogen combustion. JERA and IHI working to supply about 200 tons of ammonia to the test burners at Unit 5 from denitration tanks at the power plant site to underpin test runs. ■

Ammonia tanker berthing at a dedicated terminal

Gentari, IHI strive to deploy first ammonia-fuelled gas turbine by 2026

Petronas affiliate Gentari Hydrogen has teamed up with Japan's IHI Corp to progress commercialisation of IM270 – a fully ammonia-fuelled gas turbine developed by IHI. Commercial application of the IM270, scheduled for 2026, could be the world's first fully ammonia-powered gas turbine to be deployed as the end point of a green ammonia value chain in Asia Pacific.

The memorandum, signed by Gentari and IHI, stipulates the production, transportation, storage and utilisation of green ammonia (NH_3) – made from hydrogen and nitrogen – in Asia Pacific as well as other areas of mutual interest. Through their cooperation, Gentari and IHI want to create demand for the clean-burning fuel in Malaysia and the wider region, targeting the fertiliser industry and especially electric power generators.

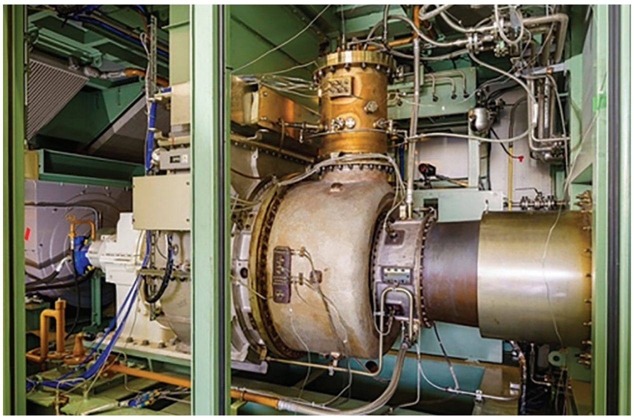
As NH3 does not obtain carbon (C), is emits no CO_2 when burnt, but the fuel as an inherently lower flammability which makes it harder to burn than natural gas. "Until now, when operating gas turbines at ammonia co-firing rate of over 70%, nitrous oxide (N_2O) which has a greenhouse warming effect around 300 times that of CO_2, was susceptible to formation, nullifying the effect of reducing CO_2emissions," IHI stated.

NH3-capable combustion

IHI is close to piloting its ammonia combustion technology in Japan. Tests at a new combustor on the 2,000-kilowatt-class gas turbine at IHI Yokohama Works, achieved a greenhouse gas reduction rate of over 99%, even when the ammonia fuel ratio is at 70~100%, and IHI verified the output of 2,000kW when mono-firing liquid ammonia.

Ammonia burners, developed by IHI; will be used for generating 20% of the heating value at Hekinan thermal power plant's Unit 4. Procurement of the ammonia will be handled by JERA, Japan's largest LNG importer and power generator.

Apart from burners, IHI Corp has teamed up with GE Gas Power to develop fullfledged gas turbines that can solely run on ammonia by 2030. "We want to satisfy demand for large-scale ammonia gas turbines (...) and expand the fuel ammonia value chain," said Hiroshi Ide, president of IHI whose hydrogen- and ammonia-utilization technologies are meant to be used for GE's 6F.03, 7F and 9F gas turbines. ■



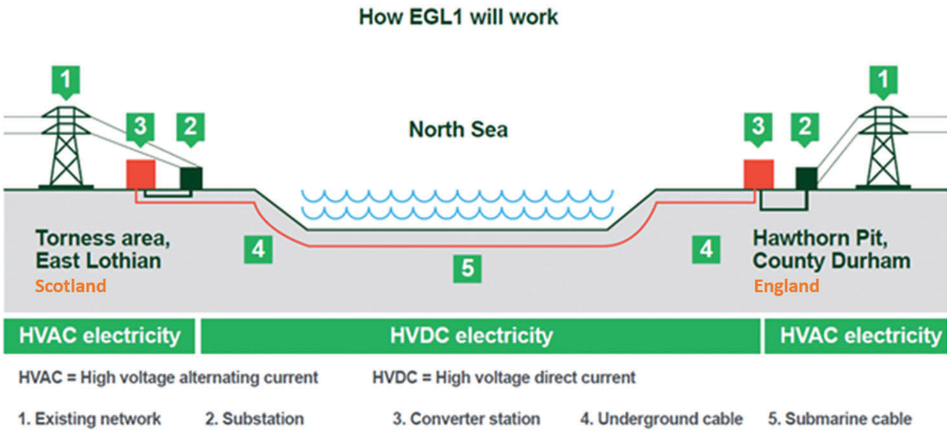
2,000 kW-class IM270 turbine at IHI Yokohama Works

National Grid awards £1bn contract for UK's first east coast subsea link

Eastern Green Link 1 (EGL1), a joint venture between National Grid and SP Transmission, has awarded a £1 billion contract to GE and Mytilineos to build the UK's first east coast subsea link. The 2 gigawatt (GW), 525 kilovolt (kV) cable will run from southeast Scotland to county Durham, England, with the design phase set to begin in January 2024.

Construction is scheduled to start in 2025. The EGL 1 project is part of the UK's energy grid transformation – a large overhaul to help transmit green energy from where it is generated to where it is need. This require multi-billion investments in new electricity transmission projects across the country.

The east coast subsea link will run from Torness in East Lothian, Scotland to Hawthorn Pit in county Durham, England. National Grid hailed the project as a "major economic win for the UK" given that significant works will be carried out by UK-based companies. Stafford-based GE Grid Solutions will be providing HVDC valves and control systems, as well as HVDC transformers together with Mytilineos. ■



Construction of 2 GW SuedOstLink starts in Bavaria

Grid operator TenneT has begun construction of a 540-kilometre power transmission line with a capacity of 2 gigawatt (GW), designated to bring offshore wind energy to southern Germany. Work just started at SuedOstLink's converter station Isar near Landshut just started – with several years of delay – while the northern converter near Magdeburg is in the making since March.

Most of Germany's renewable energy is produced on land and at sea by large wind power plants in the north, though demand is centred in the industrialised Ruhr region and particularly in the South of the country. The two TSO TenneT and 50Herz are hence building the SuedOstLink – set to run from Wolmirstedt in Saxony-Anhalt to near Landshut in Bavaria – capable to transmit enough electricity for four million households.

In the event of excess wind energy, the northern unit will convert the alternating current into direct current, for the electricity to be transported southbound via underground cables with a voltage of 525 kilovolts. The Isar unit in Bavaria then converts the incoming direct current back into alternating current and feeds it into the distribution grid. The voltage-sourced converters, supplied by Siemens, control the flow of electricity also with regard to reactive power and can blackstart the grid.

Over the coming twenty years, Germany needs thousands of kilometres of new power transmission lines to realise the goal of climate neutrality in the power generation sector. "These lines have to be planned, licensed and built quickly," the government's maritime economy coordinator Dieter Janecek said. About 13,700 kilometres of new power lines spread over almost 120 individual projects are currently being planned or constructed in Germany, figures by the energy ministry show. But the grid expansion has ground to a halt for several years amid fierce resistance from local residents, notably in Bavaria. ■

Route of new German power transmission links

TAQA eyes taking stake in Greece-Cyprus HVDC power link

Abu Dhabi National Energy Company (TAQA) is considering joining a project to develop a 900-km high-voltage direct current (HVDC) electricity interconnection between Greece and Cyprus. TAQA prepares to join Greece's TSO and the Cyprus government as shareholders in a project whose construction is expected to cost approximately €1.9 billion and would end Cyprus' energy isolation.

If realised the Greece-Cyprus power cable would encourage the development and export of clean energy to both Cyprus, Greece and the rest of the European Union. Cyprus and Greece have some of the highest potential in Europe for both solar and onshore and offshore wind power generation, hence the interconnector could reduce the cost of electricity in the region, especially if it will be extended to Israel (see map). As an EU Project of Common Interest, the envisaged interconnector has already been approved for a €657 million grant from the "Connecting Europe Facility."

Manos Manousakis, CEO of the Independent Power Transmission Operation of Greece (IPTO) said "the interconnection between Greece and Cyprus, which is the most mature segment, is [soon] entering construction phase, beginning from the subsea cable which will be built by Nexans." In July 2023, NEXANS was awarded a €1.43 billion contract for the HVDC cables contract while Siemens AG was chosen as the preferred bidder for the contract to build two VSC HVDC converter stations. ■

First fire at Tallawara B successful, heralds commissioning in early 2024

EnergyAustralia has successfully completed the first test fire at its 318 MW Tallawarra B gas power station with a view to commissioning the $300 million peaking plant in early 2024. Situated on the shores of Lake Illawarra in New South Wales, the plant complements the existing Tallawarra A unit (435 MW) and facilitates the region's renewables build-out.

The fast-ramp unit will be operational just in time to meet peaking power demand in the southern hemisphere summer season. Tallawarra B Project Director Ian Black underlined the "importance of completing this project to help provide energy security for homes and businesses in New South Wales with what is predicted to be a hot and dry El Niño summer."

Hydrogen-ready

Powered by GE turbines, Tallawarra B will be Australia's first peaking plant capable to run on a blend of natural gas and hydrogen. The operator said it plans to co-fire 200,000 kilograms of green hydrogen annually from 2025.

Federal energy minister Angus Taylor said Tallawarra B is "the first dispatchable energy generation project built in NSW in over a decade," in contrast to the otherwise dominant renewable build-out. The flexible plant can hence help balance a looming capacity deficit as AGL retires its large Liddell coal power unit over the coming months. Prior to the Liddell closure, the NSW government wants to secure at least 1,000 MW of new flexible, fast-ramp capacity to avert to risk of price spikes and power shortages. ■

Tallawarra A and B on the western shores of Lake Illawarra

Ansaldo equipment to power Almaty CHP-3

Ansaldo Energia has agreed to supply two AE94.2 gas turbines, two generators and auxiliary components for the reconstruction of the Almaty combined heat and power plant (CHP-3) in Kazakhstan. A reservation agreement signed with KBI Energy Group, the EPC contractor for the project, stipulates an early start of components production.

The reservation agreement makes the customer pre-empt his production lines against payment of an advance on the contract's total amount, Ansaldo specified, adding the actual contact will be signed in the next months. The deal allows for a swift start of production, the Italian manufacturer said, vowing to deliver the ordered turbines and generators in an "extremely rapid" manner.

The overall Almaty Electric Station's project portfolio includes the construction of a combined-cycle gas plant with a capacity of 545 MW at the Almaty CHP-3, the modernisation of Almaty CHP-2 and the reconstruction of the ageing Almaty CHP-1 into a 250 MW combined-cycle plant. ■

Invictus and Mbuyu Energy sign gas sales MoU for 1 GW power project

Australia's Invictus Energy has signed an updated memorandum with Mbyuy Energy to supply natural gas for their 500 MW power project in Zimbabwe whose capacity could be doubled to 1,000 MW. Fuel for the power station will originate from Invictus' 80%-owned and operated Cabora Bassa field, with the MoU being a precursor to a full long-term gas sale agreement.

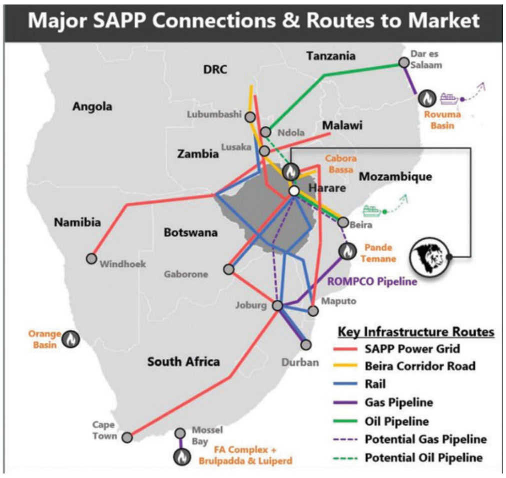
If expanded to 1 GW, the power plant's fuel needs is forecasted to equate about 1.4 trillion cubic feet of natural gas over 20 years. Both MoU parties will now asses assess the feasibility of developing the project utilising gas produced from the Mukuyu field or any adjacent discovery.

Invictus managing director Scott Macmillan called the MoU to develop the combined-cycle gas power plant a "step forward in our early commercialisation strategy" given that the potential offtake "will underpin the commercialisation of the Mukuyu gas field."

Development of the combined-cycle gas power project will be synchronized with the broader development of the Mukuyu field and the Cabora Bassa project. This includes gas production, transportation and the processing infrastructure required to provide natural gas feedstock to the power plant, developers specified. In terms of site, preliminary feasibility studies have identified a number of suitable locations that would allow feeding electricity into the local grid as well as potentially exporting some volumes to Southern Africa Power Pool (SAPP).

The MoU stipulates that Mbuyu Energy will be provided with an initial twelve-month exclusivity period and preferred partner status for the Power Project from the completion of the Mukuyu-2 well drilling activity. A feasibility study will determine market clearing price for electricity produced (i.e. a gas price that can support investment in the upstream project, and related infrastructure necessary for the power project. ■

Rig at Invictus' Mukuyu drill site in Zimbabwe



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