PPO PROJECTS

PIPELINE, PLANT & OFFSHORE

DEC / JAN 2023

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Barossa drilling operations suspended following the Federal Court's decision

MAHALO GAS PROJECT ▲ LEIGH CREEK ENERGY PROJECT ▲ CLIFF HEAD OIL FIELD

APGA

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COMMITTEES

MOLLY HANCOCK

Natural gas more important than ever

It is hard to believe this is the last edition of *PPO Projects* for 2022. What a year it has been. From company mergers to key projects starting construction, the year has been nothing short of eventful.

However, since I last joined you, the International Energy Agency's report, *World Energy Outlook 2022*, has been released, highlighting the importance that gas holds in the energy market in the wake of Russia's war on Ukraine.

The IEA's report outlined the importance of gas in three potential global scenarios on the shift to low emissions. In summary, the report found that there are three scenarios - the Announced Pledges Scenario (APS), the Stated Policies Scenario (STEPS), and the Net Zero Emissions by 2050 Scenario (NZE).

APS reveals that global demand for natural gas will be lower in 2030 than 2021 but, in that time, increases in developing Asian markets (by 67 per cent) and in India (by 20 per cent).

The STEPS found that natural gas demand rises 0.4 per cent per year until 2030, reaching 4400 bcm and then stabilising until 2050. The Asia-Pacific region increases demand by 13 per cent by 2030, and 28 per cent by 2050.

NZE scenario shows demand is lower in 2030, and what demand there is, will be met by non-combustion natural gas or natural gas producers utilising carbon capture and utilisation technology.

Chief Executive of APPEA Samantha McCulloch said in a statement following the report that it is the versatility of natural gas that underlines its importance in the different scenarios laid out in the report.

"The *World Energy Outlook* highlights that, as the global energy market is being reshaped following the Russian invasion of Ukraine, the ongoing recovery from the COVID-19 global pandemic and to meet emissions reduction commitments, natural gas remains an important part of a cleaner energy future," McCulloch said.

"Demand for natural gas in the fast-growing developing Asian market continues to provide an economic opportunity for Australia. Ongoing investment, to maintain existing production and facilities, or to fund growth, is required under all scenarios."

While natural gas continues to show its important in Australia's net-zero journey, energy retailers in Western Australia will be required to buy a percentage of hydrogen-fuelled energy to support the growing industry.

Western Australia has opened an invitation to comment on a potential renewable hydrogen target for electricity generation for the state's main electricity grid in the southwest interconnected system.

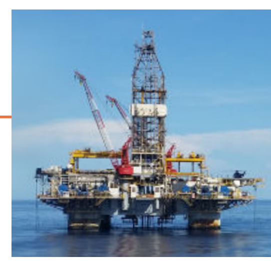
As it stands, the target will require energy retailers to procure a certain percentage of electricity fuelled by renewable hydrogen.

The requisite would create a stable local market for hydrogen and, in turn, provide support of emerging hydrogen projects and have some stabilising effect on the energy grid.

With 2022 coming to an end, the team here at *PPO Projects* wishes you all a happy and safe Christmas and New Year. We look forward to joining in 2023 with all the latest project updates happening around Australasia.

Happy Reading!

Molly Hancock, Managing Editor
molly.hancock@primecreative.com.au



FRONT COVER
Barossa Offshore Project
Image credit: Santos

PPOPROJECTS
PIPELINE, PLANT & OFFSHORE

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Black & Veatch joins the Australian Hydrogen Council

Black & Veatch is at the forefront when it comes to delivering on sustainable infrastructure projects. An employee-owned engineering, procurement, consulting and construction company, Black & Veatch has a legacy dating back over 100 years.

It's no secret that Australia has all the resources necessary to support its push towards becoming a key player on the world stage for hydrogen production. State governments, especially Western Australia, Queensland and South Australia, and the Northern Territory, have been actively pursuing opportunities to capitalise on the country's unique abundance of resources.

Black & Veatch recently joined the Australian Hydrogen Council (AHC), further cementing its commitment to sustainability projects in Australia as the country gears up to become a hydrogen powerhouse.

The company's vice president and director Australia Pacific Mick Scrivens says that joining the AHC opens opportunities to work with other innovators as Australia's aspirations shift.

"It lets us collaborate with engineering leaders, technology providers, equipment providers, and relevant state and federal government leaders as well," he says. "We're all looking for a common platform to develop the hydrogen industry in Australia. Black & Veatch is excited to help realise Australia's ambitions to supply green ammonia to the Asian, European and domestic markets as a replacement for fossil fuels in the years to come."

WHY HYDROGEN AND AMMONIA?

The ammonia industry has existed for many decades, producing for agriculture and domestic applications – but most often used for explosives in the mining industry.

The ammonia molecule is NH_3 – it requires three hydrogen atoms for each nitrogen atom. But the hydrogen has to be produced somewhere. Scrivens explains that, in the case of ammonia production, emissions are produced from the process being powered by fossil fuels, resulting in what's known as 'grey ammonia'. Hydrogen is produced by a process called steam methane reforming (SMR), which also uses natural gas – both processes involve high carbon dioxide (CO_2) emissions.

"To capture the ammonia export opportunity, Australia needs to focus on producing blue or green ammonia," says Scrivens. "Carbon capture can be integrated into existing processes to produce blue ammonia while electrolysis technology powered by renewable energy can split water to produce green hydrogen (and oxygen); and then the hydrogen can be converted into liquid ammonia for storage and shipment."

Emissions don't stop with the production of ammonia. The large amount of ammonia imported to the country also comes with its own emissions from the ships that carry it to Australia's shores.

Existing mechanisms are being used to inspire changes to this process. In the same way that liquefied natural gas (LNG) vessels are sometimes powered by the very products they transport, there are now developments with some providers to run fleets on the ammonia they carry.

"It's about reducing the CO_2 emissions from us, as humans on this planet that we're entrusted to take care of. Decarbonisation is the eventual elimination of the carbon that we emit through day-to-day life, and from the various industries that have made our country successful," Scrivens says.

However, decarbonisation challenges are complex. According to Black & Veatch's 2021 Corporate Sustainability Goal Setting and Measurement Report, more than 80 percent of large corporations (with revenues over US$250 million) had set greenhouse gas emissions targets. Yet, 25 percent of their CEOs admitted to not knowing how they would achieve these targets.

Scrivens advises mitigating risks by developing agile decarbonisation roadmaps that systematically assess existing and emerging technologies over multiple years.


Mick Scrivens, Black and Veatch's vice president and director Australia Pacific.

"Black & Veatch is technology agnostic and a leader in deploying many first-of-a-kind technology; this allows us to assemble the right solution for the client's challenge in hand and with hydrogen and ammonia, we are drawing on our wealth of experience in LNG and gas processes, carbon capture, renewable energy, water treatment and much more," says Scrivens.

COLLABORATION THROUGH THE AHC

The AHC brings industry leaders together to make a real impact. Long histories in the energy sector equip companies with a strong working knowledge of the procedures, specifications and standards required to make new processes work while new technologies are developed.

Scrivens says that the AHC is a powerful think tank for these projects.

"The gas industry and the oil industry have been around for hundreds of years with well-defined regulatory requirements,


Joining the AHC let's Black & Veatch collaborate with leaders in engineering, technology, equipment and government.

specifications, and standards. Now, we're doing something a little different with hydrogen, and those factors need to be validated, to be developed. Having the AHC and all its members working alongside government bodies to put the guidelines in place around the hydrogen industry is a great part of that thought leadership and thought sharing. It's fantastic!" Scrivens says.

THE PATH FORWARD

Australia is aiming to achieve a sevenfold increase in the production volume of ammonia within 14 years. Scrivens says the data shows that within 14 years, Australia will be the second largest exporter of green ammonia, to the world stage.

Key to this is the way projects are designed. Scrivens says there's no sense in creating the world's largest electrolyser if there isn't an immediate market for that kind of production. He says that instead it would be prudent to create scalable projects, that can meet current demands and expand as those demands increase.

What's required to make the transition successful, he says, is both the will and the desire to see the process through. While many of the projects currently underway require a large capital expenditure, the federal government has shown the desire to become a world leader in hydrogen production as well as green ammonia.

Significant investments will be required to build and convert infrastructure for the hydrogen and ammonia production processes as well as many necessary upstream renewables and related export facilities.

Narrowing down the export locations when thinking through development criteria and infrastructure constraints is one approach. For a start, map out existing energy infrastructure depending on the development requirements, including electric transmission lines or gas pipelines to transport the hydrogen.

Another approach is leveraging existing infrastructure, for instance, converting liquefied natural gas (LNG) infrastructure into hybrid ammonia and LNG infrastructure, to help reduce development cost.

Scrivens anticipates that the hydrogen industry will develop in a similar way the solar sector did over the last decade, with the cost of panels, infrastructure and equipment decreasing dramatically.

"I believe for the hydrogen industry, the same will happen. There are five or six global providers of key equipment. They're working hard with their research and development teams to scale up to meet the demands of what's forecasted for equipment supply to meet the aspirations of countries like Australia, which wants to be the world's leading hydrogen exporter," he says.

For more information, visit bv.com

AVEVA's technology fosters the green hydrogen future

AVEVA UOC for Sustainability.

Multinational industrial software company AVEVA uses highly developed and innovative software that empowers customers to design, optimise and operate across the entire project lifecycle.

AVEVA has been working with technology to support the energy industry for more than 50 years and, during this time, has supported some of the biggest and most complicated projects around the world. With the energy transition increasingly on the agenda, AVEVA is excited to be at the forefront of sustainable innovation, working with a number of partners in the green hydrogen sector – a sector that is predicted to supply up to 25 per cent of the world's energy needs by 2050.

AVEVA'S Senior Pre-sales Consultant Alain Braibant's job is to support customers with complicated projects across a variety of industries within the Pacific region.

"We see it as our mission to connect our customers with trusted information and insight, to help them to operate more efficiently as they accelerate their progress towards more sustainable operations," says Braibant.

As Australia pushes hard towards a hydrogen economy, AVEVA's software solutions are making sure that operators are empowered to make the best choices with the best outcomes. To that end, the group are working closely with vanguards of the green hydrogen industry, Fortescue Future Industries, which has selected a suite of AVEVA'S cloud-based tools to help standardise engineering for its local hydrogen plant in Queensland. Whilst helping streamline the design for its local facility, the platform will serve as a blueprint for operations globally. It also aligns with the company's ambition to double the world's green hydrogen-production ability by 2030, as well sourcing 15 million tonnes from the Asia Pacific region – 12 million tonnes from Australia alone.

Scott Robertson is the Business Development Manager for AVEVA's Engineering Portfolio in the Pacific region. He says that in addition to these exciting new partnerships, the company continues to support some of the largest energy companies that have been supplying energy to Australia for decades.

"These companies all have emerging energy divisions focused on reducing their carbon footprint and generating green energy. We're using our tools and expertise to help them design, execute and accelerate those plans, and with great success," he says. "One local example is AGL Energy, one of Australia's largest energy providers, that is using AVEVA's predictive analytics and information management solutions to help with its renewable energy adoption and growth plans, resulting in an $18.5 million saving in a one-year period – while avoiding a catastrophic shutdown that could have cost in the order of $50-70 million."

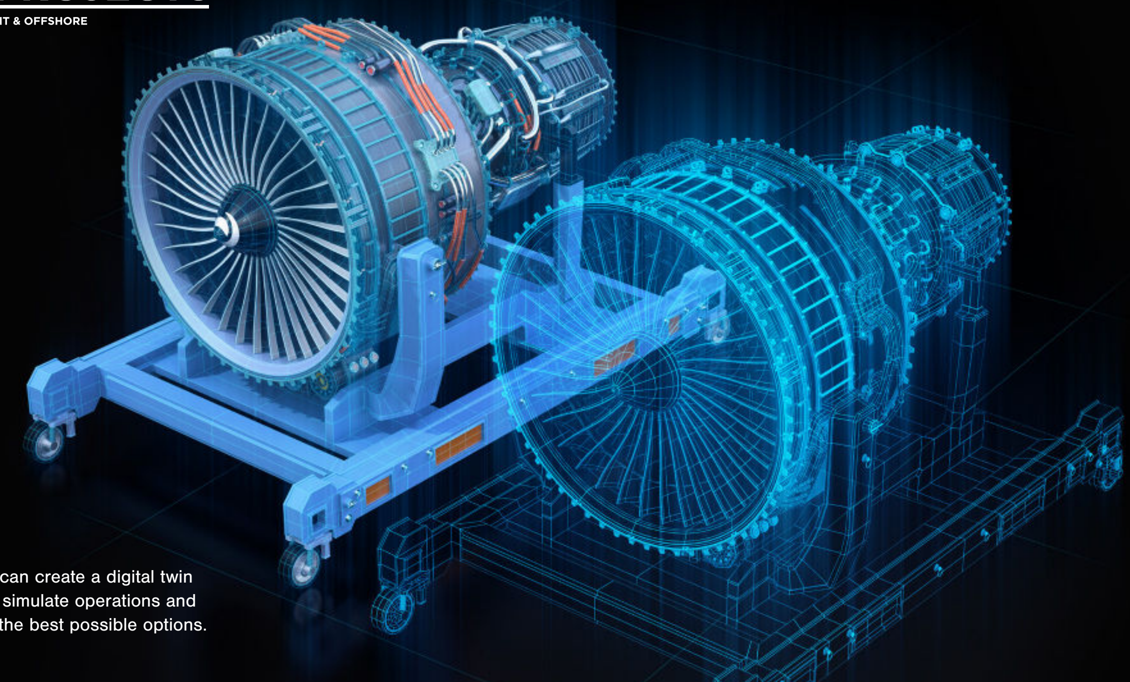
ONE TOOL WITH ALL THE ANSWERS

AVEVA's software is a suite of analytical tools that can be leveraged across the full lifecycle of a project. According to Robertson, there's a lot to be said for the benefits of quite basic analysis work.

From the front-end engineering design (FEED) stages through to construction and operations, AVEVA's software takes data from every single point along the production pathway.

The software works by creating what AVEVA calls a 'digital twin', which is a virtual representation of a real-world physical system that connects real-time data sources, models and analytics across the asset lifecycle in one single place. This allows organisations to more effectively visualise and predict project deployment, to ensure maximum efficiency and profitability throughout.

"For example, if you're looking at green hydrogen, there are so many choices to be made – energy generation, storage, the equipment being used to produce it," says Braibant.



Operators can create a digital twin in order to simulate operations and determine the best possible options.

More than that, the software even considers how operators will use the hydrogen, be it liquifying it, injecting it into a pipeline, using it to produce ammonia and then exporting it.

"Through our simulation we can take into consideration how a small change to the project design will impact the capital expenditure, operational expense, the impact on emissions, etc. That way, operators can make the optimum choice based on their objectives," Braibant says.

Robertson explains that the software also allows the user to self-select their level of engagement. There's a drop-and-drag function from the software's library which allows operators to place a specific electrolyser into the virtual project to determine how it will impact it overall, including required shutdown, energy offsets, predicted output, etc.

At a high level, the software provides a platform for information management, either for project data for engineers, or operational data from the plan.

INVALUABLE AT EVERY STAGE

One of the areas where AVEVA's software really shines in the pre-FEED stages, when operators are determining the parameters of a project – what it will look like, what is required, and how it will run.

By starting with the objectives for a project, the software allows the customer to determine exactly where capital is best placed for maximum effect.

Operators can determine, for example, how many wind turbines or solar panels are required to run a specific model of electrolyser, or how much power will needs to be bought, and how much generated and sold downstream to best offset that cost.

The software can also help when companies are striving to reduce emissions from existing projects in order to make them more sustainable.

"If you have an existing ammonia facility that is using methane steam reforming to generate hydrogen, and the objective is to start using green hydrogen, then you can actually have both operations running on the software for comparison," says Braibant. "It's about efficiency, but also about innovation, because we give customers the ability to quickly assess the changes they could make."

Roberston explains that companies can't just switch off all their diesel generators and be done with it.

"But if you take a brownfield project you can determine what its emissions are and work out how much renewable energy needs to be used to reduce that, step by step," he says.

It is often a number of small changes, made through informed decisions that are enabled by the software, that collectively can have a big impact on a project.

Users can use the software to 'walk around' a 3D model of the plant.

ENSURING THE INDUSTRY IS SAFE

Training new operators in the emerging hydrogen industry is also important. If Australia's hydrogen economy is going to be sustainable and safe, then it needs to be equipped with a skilled workforce.

AVEVA's software means the expense of expertise is significantly lessened. Industry and subject matter experts are able to interact with the digital models for an operation without having to be flown in. This expertise can be tapped into for training purposes.

In addition to the time, cost and sustainability benefits of avoiding such travel, the ability to safely run different scenarios through the system, without impacting the actual operations and equipment, is very valuable. The software can also generate 3D models of a plant, which lets users 'walk around' the 3D model of a plant to get an idea of what the space looks like and how it operates.

"By providing these virtual learning tools, you allow students and newer operators to get familiar with a specialised field before they even set foot in a plant. This is vital, particularly for our shifting workforce demography and digital natives entering the workforce," says Braibant. "In fact, AVEVA's virtual training solutions are being leveraged by the world's leading chemical company, BASF, which successfully trains over 600 operators each year in a fully immersive simulation environment".

CONTINUING TO EVOLVE

Proof of AVEVA's success in facilitating the capability of operators in the energy industry comes from its long history of doing just that.

The company is a constant innovator in the field of technical software. As technology continues to emerge, improve and evolve, AVEVA remains at the forefront of this transformation, ensuring their customers have the digital tools they need to thrive.

"We're starting to see people integrate other technologies together with our software," says Braibant. "Our digital twin is a combination of a projects data, model and visualisation, but we're seeing the digital twin being combined with things like Machine Learning to get the most out of the system."

As new technologies and innovations emerge in the green hydrogen industry, AVEVA's software can empower operators to maintain the leading edge and safeguard their transition into a low carbon future.

Learn more about how AVEVA is supporting the energy transition. Hydrogen | AVEVA https://www.aveva.com/en/industries/oil-gas/hydrogen/

AVEVA's software adds value along the entire project lifecycle.

AOG Energy is gearing up for its 2023 return

AOG Energy is Australia's premier oil, gas and energy trade event that is held annually in Perth – and it will be returning in 2023.

For over 40 years, AOG Energy – formally known as the Australasian Oil & Gas Exhibition and Conference – has brought the entire supply chain together in the oil and gas epicentre of Australia.

Returning to Perth with a renewed focus on the future, AOG Energy will showcase both local and international innovation and explore future opportunities within the industry. The last few years have given both AOG Energy and the industry as a whole time to take stock of what role can be played in the future energy economy.

AOG Energy Commercial Director Bill Hare has helped run the event since 2008 and says it's exciting to be returning in 2023 with a dedicated platform for the global energy community to reconnect and drive new energy opportunities.

"COVID-19 was a difficult time for all within our industry. Not being able to bring people together for almost two years, there's now an enormous pent-up demand for like-minded people to come back together and reconnect," he says.

"There's palpable excitement with what's to come; our committee is really reenergised and refreshed and quite a bit has happened within the industry itself since AOG Energy came together."

AOG Energy Exhibition.

A RENEWED FOCUS ON RENEWABLES

Since the last international show in 2020, the energy industry has continued to evolve. Hydrogen and offshore wind are coming to the forefront of Australia's energy industry and economy, drawing the interest of many international industry experts.

As a natural part of that transition, AOG Energy is touching on a collection of key themes designed to pinpoint and highlight the current state of oil, gas, and energy in Australia. These key themes will touch upon the energy transition including low emissions technology, decommissioning, offshore wind, decarbonisation including carbon capture and storage (CCS) and utilisation.

For the live exhibition, there will be a broader showcase of methodologies, strategies, and emerging technologies to navigate the energy transition and explore new low and zero carbon ways of providing energy.

SO MUCH TO SEE AT AOG ENERGY

Alongside the exhibition floor, AOG Energy will host a free industry-led conference program. Featuring three dedicated theatres - keynote speakers will address opportunities, trends, and challenges in the industry. The conference will see a significant focus on renewables and hydrogen from industry-leading players in the clean energy sector.

"The Centre of Decommissioning Australia (CODA), one of the event's major sponsors, will be building a decommissioning hub at the show to help inform and educate the industry and connecting and collaborating the industry about the opportunities decommissioning can yield," says Hare.

Similarly, National Energy Resources Australia (NERA), will have the NERA Technology Discovery Centre where attendees can discover how it is working to support Australia's energy transition. The NERA team will be joined by technology SME's from their programs and wider energy network, each with an innovative clean-tech solution to the challenges facing the energy sector.

To add to the excitement, NERA will be running a pitch-battle at the show which is sure to get many attendees involved.

"The program, LETs Pitch 2023, is looking for Australian low emissions SME's with technology solutions to help accelerate the nation's net-zero future. It's open for start-up or scale-up businesses with a technology that includes clean hydrogen, low emissions electricity, electrification and fuel switching, and CCS," says Hare.

From those applications, eight companies will be shortlisted to receive tailored pitch mentoring and coaching ahead of the live pitch event on day one of AOG Energy.

An incredible opportunity, the NERA LETs Pitch program, along with the CODA

AOG Energy Conference.

decommissioning hub, are two of the many events taking place at AOG Energy.

REFORGING CONNECTIONS

"It's an exciting opportunity to bring like-minded people together once again," says Hare.

"An event like AOG Energy has the formal side of it through which people get to deepen their knowledge and understanding of the industry. But where the magic really happens is when people come together; that serendipity of forming new connections with others and that human connection."

Such events featuring at AOG Energy include the Subsea Welcome Drinks. Kicking off the week before the doors of the convention officially open, the Subsea Welcome Drinks is the first of many networking events for the industry to reunite over a few drinks and canapes. The official opening party, held on day one of the exhibition is yet another chance for attendees to come together. There, leaders of the industry, colleagues and clients will gather in a relaxed garden party setting, featuring entertainment, food, and drinks.

While this is AOG Energy's largest networking event and certainly not one to be missed, it is not the only one; the annual Diversity and Inclusion Breakfast is a thought-provoking morning.

"The theme for the breakfast is driving change to create respectful workplaces," says Hare.

Diversity and inclusion leaders from across the oil, gas and energy industry come together at the breakfast not only to discuss and implement strategies to improve diversity, equity, and inclusion in the workplace – but also to get to know one another better.

"While ideas like this will definitely permeate the exhibition and conference as a whole, it's important to be able to establish an event like the Diversity and Inclusion Breakfast where we as an industry can come together," he says.

For the last four decades, AOG Energy has brought the entire supply chain together in the oil and gas epicentre in Australia – and 2023 is shaping up to be bigger and better than ever.

"AOG Energy will grant the chance for industry members to come together to establish connections with engineers, manufacturers, designers, contractors and other industry leaders," says Hare.

"We're looking forward to getting to reconnect with familiar faces – and get to know new ones across the three-day event."

AOG Energy will be the destination to reconnect, discover opportunity, and stimulate business growth in 2023.

AOG Energy Official Opening Party.

For more information or to register to attend AOG Energy 2023, visit www.aogexpo.com.au.

SOLE GAS PROJECT

ONSHORE AND OFFSHORE | PIPELINE | IN OPERATION | PROPONENT: COOPER ENERGY

Cooper Energy
Level 10
60 Waymouth Street
Adelaide SA 5000
P: (08) 8100 4900

PIPE STATS
Capacity: 68 TJ/day

OWNERSHIP
Cooper Energy 100%

PIPELINE CONTRACTORS
Diamond Offshore: Drilling contractor
Subsea 7: Subsea pipeline and installation

SCOPE

Previous operator Santos first proposed the development of the Sole gas field off the coast of Victoria. Santos sold the Sole project to Cooper Energy in 2016. A 40 km subsea pipeline connects the field to the Orbost gas plant on the Victorian coast, 10 km from Orbost. Operations at the Orbost gas processing plant involve separation, compression and dehydration of raw gas. Sales gas is then transported to the Eastern Gas Pipeline.

PREVIOUS HISTORY

August 2022: Cooper Energy has announced that the completion of its acquisition of the Orbost Gas Processing Plant from APA Group in early August 2022. APA Group will continue to operate the plant on behalf of Cooper Energy under a transactional services agreement until the plant's major hazard facilities license is transferred to Cooper Energy. The acquisition costs between $270 million and $330 million via four instalments. Additionally, Cooper Energy will undertake a fully underwritten $244 million equity offering comprising of an $84 million placement to institutional investors and a 2-for-5 accelerated, non-renounceable entitlement offer to raise a total of $160 million.

7 July 2022: Cooper Energy stated that the average processing rate for May was 55.7 terajoules per day (TJ/d) at the OGPP located in the Sole gas field. This rate is 36 per cent higher than the average April processing rate of 41 TJ/d. The OGPP performed at or about 60 TJ/d for 21 days during May, with a maximum rate of 66 TJ/d achieved. The OGPP processing rate was reduced to 36.4 TJ/d on average during absorber cleans for 8 days in May.

22 June 2022: Cooper Energy has entered into agreements with leading Australian energy infrastructure businesses APA Group to acquire the Orbost gas processing plant (OGPP). The acquisition will cost between $270 million and $330 million via four instalments. Additionally, Cooper Energy will also undertake a fully underwritten $244 million equity offering comprising of an $84 million placement to institutional investors and a 2-for-5 accelerated, non-renounceable entitlement offer to raise a total of $160 million.

20 April 2022: Cooper Energy and APA Group have extended the transaction agreement for the framework for commencing Sole gas sales agreements (GSAs) and commissioning the Orbost Gas Processing Plant (OGPP). As announced on 12 April 2021, Cooper Energy exercised its option to extend the transition agreement by 12 months to 1 May 2022.
Cooper Energy advises that APA and Cooper Energy have agreed to amend the agreement to further extend by a period of two months so that the agreement now expires on 30 June 2022. The two companies are working constructively together on mutually acceptable long-term arrangements.

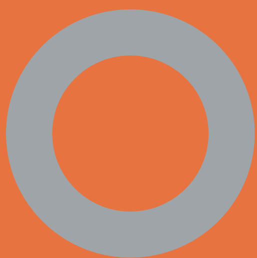
January 2022: Cooper Energy has reported that the average processing rate at the Orbost Gas Processing Plant (OGPP), owned by APA Group, reached 44.3 terajoules a day (TJ/d) in December. This indicated a 5 per cent rise compared to the month prior which recorded 42 TJ/d. The higher average processing rate in December reflects improvements due to continued optimisation of process parameters of the gas plant. Cooper Energy advised that operational improvements continued into January with a stable processing rate of 50 TJ/d to 12 January. The two sulphur absorbers operated on a planned 21-day cleaning cycle, with the ongoing optimisation and monitoring possibly resulting in an extension to the cleaning cycle. In addition, the Athena Gas Plant project reached a critical milestone during December, with first gas from the Casino, Henry and Netherby (CHN) fields introduced to the plant. This followed successful cutover of the pipeline from the Iona Gas Plant to Athena, which completed on schedule. Ramp-up of gas processing at Athena has occurred during January and processing rates of 28 TJ/d from the CHN has now been achieved.

February 2021: Cooper Energy has reported record production and sales volumes in the December 2020 half year as output has ramped up from the Sole gas field. Increased gas production from Sole underpinned an 82 per cent increase in total production to 1.20 million barrels of oil equivalent (MMboe).

WESTERN OUTER RING MAIN (WORM) PROJECT

ONSHORE | PIPELINE | UNDER CONSTRUCTION | PROPONENT: APA GROUP

Head Office
Level 25
580 George Street
Sydney NSW 2000



OWNERSHIP
APA Group: 100%

SCOPE

The Western Outer Ring Main project is a proposed high pressure, buried, gas transmission pipeline approximately 51 kilometres in length. It will address a key capacity constraint in the VTS by providing a new high-pressure connection between existing sources of natural gas supply in the north and east with those in the west of the state.

Addressing this missing link will deliver improved network reliability by increasing the amount of gas that can be stored for times of peak demand and ensuring sufficient volumes of gas can be moved where it is needed most.

The Western Outer Ring Main will help to deliver sufficient gas to Victorian homes for heating and cooking on very cold days, as well as supplying gas for power generation during times of peak electricity demand. The project also provides the opportunity for new growth suburbs on Melbourne's urban fringe to be supplied with gas as those areas are developed.

The Western Outer Ring Main project will ensure that all Victorians can continue to benefit from a reliable gas transmission system that meets the needs of the community both now and into the future.

PREVIOUS HISTORY

August 2022: Construction has begun on APA Group's Western Outer Ring Main (WORM) gas transmission project to enable larger volumes of gas to be transported to Victoria's Iona Underground Storage Facility for use during peak demand. APA Group's CEO and managing director Rob Wheals said that the WORM pipeline builds on the group's track record of investment to expand our east coast gas grid and will establish a vital new link in the Victorian Transmission System that bypasses the low-pressure network in Melbourne's CBD. This is set to increase critical gas storage at the Iona Underground Storage Facility for use during peak demand. "When completed, the WORM investment will also provide increased system capacity, reliability and security of supply to Victorian households for their heating, hot water and cooking, as well as for small and large businesses," said Wheals.

July 2022: Qube Energy has been working alongside BAO Australia to deliver over 51 km of pipes APA Group's Western Outer Ring Main (WORM) project. The project involves the delivery of 2883 lengths of line pipe, which is approximately 7168 tonnes of steel. This large stack of pipes is located at the Qube Energy site in Melbourne. The pipes will be delivered to APA Group's stockpile in Laverton and will take an estimated 300 truck loads to move in total.

2022: APA has now commenced negotiations with landholders to obtain easements to contain the pipeline. An easement is an agreement registered on the title of the land that sets out the rights of a pipeline owner to install and maintain the pipeline and also defines the restrictions on the landowner in the area of the easement. Compensation for the easement is payable to the landowner and APA will also pay landowner legal and valuation costs reasonably incurred in negotiating an easement agreement.

September 2021: The public exhibition period for the WORM EES took place from Wednesday 7 July until Tuesday 17 August 2021. Organisations, stakeholders and members of the community made submissions on the project during the exhibition period. The Minister for Planning has now appointed an Inquiry under the Environment Effects Act 1978 to review the public submissions, the EES and consider the environmental effects of the project.

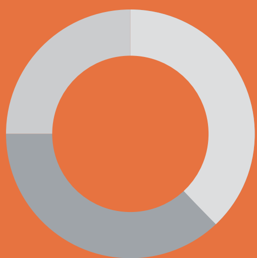
January 2021: The project hosted information sessions, face-to-face, in council areas around the proposed pipeline. In Mid-2021, the project is planning to exhibit its Environment Effects Statement (EES). This will provide an opportunity for the community to read our technical studies undertaken and the chance to leave submissions.

February 2020: DAWE determined that the Project is a 'controlled action', to be assessed under a bilateral agreement between the Commonwealth and Victorian governments. The EES for the Project has been finalised.

AUSTRALIA PACIFIC LNG (APLNG) PROJECT

GAS FIELDS | UPSTREAM EXPLORATION | PROPONENT: PRODUCTION AND PIPELINE

Proponent:
Origin Energy
GPO Box 148
Brisbane QLD 4001
P: 1800 526 369



PIPE STATS
Length: 450 km

OWNERSHIP
ConocoPhillips 37.5%
Origin Energy 37.5%
Sinopec 25%

SCOPE

APLNG is the largest producer of natural gas in eastern Australia, supplying Australian customers with natural gas and international customers with Liquefied natural gas (LNG). Each year APLNG supplies approximately 30 per cent of the Australian east coast domestic gas market. Origin Energy operates APLNG's gas fields, upstream exploration, production, and pipeline system, while ConocoPhillips operates the downstream LNG export facility and the LNG export sales business. The LNG export facility employs state-of-the-art engineering and environmental technology and, wherever possible, utilises local and regional resources. The facility has two processing trains, each with a nameplate production capacity of 4.5 mpta using the ConocoPhillips optimised Cascade Process.

PREVIOUS HISTORY

April 2022: Australia's Origin Energy has experienced a 78 per cent jump in third-quarter quarter revenue from its stake in the Australia Pacific LNG (APLNG) project due to higher spot liquefied natural gas prices and realised oil prices. Liquefied natural gas prices, high since 2021 were boosted due to the impacts of the conflict between Russia and Ukraine.

February 2022: APLNG is a joint venture between Origin Energy and ConocoPhillips, and includes a plan to develop a four-train coal seam gas (CSG) to LNG project utilising Origin's Queensland CSG reserves and resources. Origin will act as the upstream CSG operator and ConocoPhillips will be the downstream LNG operator, with the joint venture company to market the LNG. The four trains, to be constructed using Cascade technology, will have the capacity to produce up to 18 MMt/a of LNG. The project includes the construction of a 450 km gas transmission pipeline from the Surat and Bowen basins to a proposed LNG processing site located at Laird Point on Curtis Island, Gladstone. It will comprise two lateral pipelines, 44 km and 38 km in length, connecting the Condabri and Woleebee developments, respectively, with the main pipeline. Beginning east of Wandoan at the junction of the two lateral pipelines, the main pipeline extends 362 km to the north, veering east during the latter stages, with a marine crossing at The Narrows to arrive at the LNG facility. Existing easements will be used and the route deviated wherever possible to avoid impacts. The pipeline may be co-located with other CSG pipelines for more than half its length, including the section gazetted by the Queensland Government within the Callide Infrastructure Corridor State Development Area and the Gladstone State Development Area. A final investment decision for the project is expected by December 2010, with first gas expected by late 2014. Construction of the pipeline is expected to take approximately 18 months and is proposed to begin by mid-2012.

3 February 2022: Over the last quarter, Origin Energy reported a 2 per cent rise in Australia Pacific LNG (APLNG) production as its revenue rose 33 per cent. As of 31 December 2021, Origin received $555 million from the joint venture with ConocoPhillips and Sinopec. Three spot cargos captured record spot LNG prices and higher realised oil prices, contributing to APLNG's 91 per cent rise in year-to-date revenue from 2020's December quarter. While the quarter recorded higher realised oil and spot LNG prices, gas sales dropped 17 per cent on the prior comparable quarter. A drop in short-term contract volumes saw Origin's domestic revenue fall last quarter. Origin announced its acquisition of WINConnect during the last quarter for $42.2 million after tax, to add to the company's growing energy services.

Calabria said the acquisition is expected to deliver strong returns and add a significant number of embedded electric network and serviced hot water customers.

GLENARAS GAS PROJECT

ONSHORE | CSG | UNDER CONSTRUCTION | PROPONENT: GALILEE ENERGY

Galilee Energy
Level 26
71 Eagle Street
Brisbane QLD 4000
P: (07) 3177 9970

OWNERSHIP
Galilee Energy 100%

SCOPE

Galilee Energy's Glenaras gas project is located in the ATP 2019 (formerly ATP 529) tenement in the western section of the Galilee Basin. The project is designed to evaluate the quantity and quality of CSG in the Betts Creek and Aramac Coal Beds. In 2015, Galilee resumed full ownership of the project. In October 2017, Galilee announced the signing of a binding memorandum of understanding with Jemena to work together to deliver the Glenaras gas project to the domestic market.

UPDATE

October 2022: The Glenaras multi well pilot has been performing better than anticipated, according to Galilee Energy. There are currently 15 wells online, with one of the older wells awaiting a workover. Despite this, given the inherent pump redundancy that now exists across the pilot and from adjacent wells, water production is still around 30,000 BWPD with a gas rate around 90 Mscfd. Recently collected reservoir pressure date indicates that the pilot is currently performing better than ever in its history. The pressure sink is now growing faster than it has previously and the pilot is beginning to expand the volume of coal below the estimated desorption pressure. Glenaras 14, which is currently being used as an important observation well, has recorded its lowest pressure since commencement of the pilot. This confirms that the R3 seam, in the central region of the pilot, is within the critical desorption window.

PREVIOUS HISTORY

July 2022: Galilee Energy announced that its existing Glenaras pilot wells are back online as of mid-July 2022, despite an extended shutdown due to excessive rainfall in central Queensland. Water rates have since been approaching pre-drilling program rates – approximately 18,000 barrels of water per day (BWPD). As a result of recent rainfall events in the area, Galilee saw reservoir pressure increase across the Glenaras Pilot. However, the Pilot is seeing excellent reservoir connectivity and pressure drawdown across the current wells.

24 June 2022: Glenaras 29, the final well of Galilee Energy's 2022 drilling program at the multi-well pilot, has officially been completed. Glenaras 29 was the sixth and final well of the program and was drilled to a total depth of 1039 m, with all Betts Creek Beds coal seams intersected as prognosed. A total of 27 m of net coal has been confirmed with excellent gas showing.

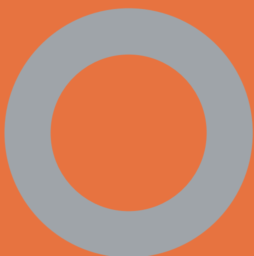
The Silver City Rig 23 was released on 22 June and is in the process of demobilising off the site. The addition of the sixth well was made possible in large part by the refund received recently and the experience gained from successfully drilling adjacent to and through the fault in the southern part of the pilot. The main challenge for the project were the risks associated with drilling in an area of maximum pressure depletion.

20 June 2022: Galilee Energy has announced that the Silver City Rig 23 has completed the fifth well of the 2022 drilling program at the multi-well pilot. Glenaras 26, the fifth well in the current program, was spudded over the June 11 and 12 weekend. The well is drilling ahead at 1011 m to a total depth of 1050 m. Moreover, Glenaras-26 was drilled to a total depth of 1,039 m with all Betts Creek Beds coal seams having been intersected as proposed. A total of 28 m of net coal has been confirmed with excellent gas shows. Since the completion of the drilling, the rig has since moved to Glenaras 29 which is the final well of the 2022 program. Moreover, Glenaras 29 has been spudded as of Friday 17 June and is drilling ahead at 850 m to a total distance of 1050 m. This well is in the centre of the existing lateral wells and will be a key well for the pilot as it will be in an area of maximum pressure depletion.

PROJECT ATLAS

ONSHORE | CSG | IN OPERATION | PROPONENT: SENEX ENERGY

Senex Energy
Level 14
144 Edward Street
Brisbane QLD 4000
P: (07) 3335 9000



OWNERSHIP
Senex Energy 100%

PIPELINE CONTRACTORS
Pipeline: Jemena
Compressions Station Construction: Valmec

SCOPE

Project Atlas involves the delivery of natural gas from coal seams on acreage located near Wandoan and Miles in Queensland's Surat Basin. The 56 km2 acreage is estimated to contain P50 recoverable gas volumes of 201 PJ, with investment of more than $200 million to drill around 100 wells and construct associated infrastructure. First gas was achieved at the project in November 2019.

PREVIOUS HISTORY

March 2022: Senex Energy has announced that the Federal Court of Australia has made orders approving the scheme of arrangement under which K-A Energy 1, subsidiary of POSCO International Corporation, will acquire 100 per cent of the shares in Senex. The company confirmed on Friday, 18 March that it had lodged with the Australian Securities and Investments Commission (ASIC) an office copy of the orders made by the Federal Court of Australia approving the scheme of arrangement.
The scheme is also contingent on the completion of the proposed acquisition of natural gas fields PL 209 and PL 445.
February 2022: Senex Energy has reported a "robust" half-year for the 2022 financial year, delivering a significant increase in production and strong sales revenue. The company revealed a natural gas production of 10.2 petajoules (PJ), up 29 per cent from the previous half-year, and a sales revenue of $74.1 million, up 65 per cent.
January 2022: Senex Energy has announced it has completed the acquisition of the undeveloped Australia Pacific LNG (APLNG) gas fields PL 209 and PL 445. The acquisition of the fields, adjacent to Senex's Atlas field, was completed on 17 January 2022 following the announcement of the intended acquisition on 8 November 2021. Completion of the acquisition of the fields is one of the conditions precedent to the scheme implementation agreement (SIA) announced to the ASX on 13 December 2021.
August 2021: Senex Energy has announced the final investment decision (FID) has been taken for the $40 million expansion of natural gas production at Atlas by 50 per cent to 18 petajoules (PJ/year). Managing director and CEO Ian Davies said the Atlas expansion project is yet another example of the low-risk, high-return organic growth opportunities available to Senex with its established hub-and-spoke infrastructure operating model.
February 2021: Senex Energy outlined in its quarterly report that daily production at Atlas reached 30 TJ/d subsequent to quarter end and continues to track towards initial nameplate capacity of 32 TJ/d. In addition, activities at Atlas are progressing, including work with Jemena on front-end engineering design (FEED) and long lead item planning for the gas processing facility expansion, and FID targeted for the second half of the 2021 financial year.
September 2020: Senex Energy has been awarded additional Atlas acreage as part of the Queensland Government's domestic gas acreage tender process. The Atlas acreage is immediately adjacent to its existing development in the Bowen Basin, and on trend with the Scotia and Meridian gas fields. As a result, this will enhance the company's exisiting development, with the contiguous block bounded by prolific has producing acreage, and resource quality and reservoir performance expected to be high-quality.
July 2020: Senex Energy has reported a 21 per cent increase in Surat Basin 2P gas reserves to 239 petajoules (PJ) following the execution of its natural gas developments in Queensland. In an independently assessed estimate of reserves and contingent resources, the company's appraisal and development drilling results at Atlas have driven a 62 per cent increase in 2P gas reserves, with a 90 PJ increase to 234 PJ.

MAHALO PROJECT

ONSHORE | CSG | UNDER CONSTRUCTION | PROPONENT: COMET RIDGE

Comet Ridge
GPO Box 798
Brisbane QLD 4001
P: (07) 3221 3661

OWNERSHIP
Comet Ridge 40%
Santos 30%
APLNG 30%

SCOPE

The Mahalo project is located in the ATP 337P permit in the Denison Trough. This area is prospective for coal seam gas in Permian aged coals that are draped over a large north-south trending structural high known as the Comet Ridge. These coals have proven to be productive at the Origin Energy Spring Gully coal seam gas development project 150 km to the south on the same structural high. The Mahalo project has a range of potential volumes of gas in place ranging from a minimum of 181 Bcf up to a maximum of 990 Bcf. The most likely volume is estimated to be in excess of 400 Bcf.

UPDATE

27 September 2022: Comet Ridge has received a notice from Santos to purchase the 12.86 per cent option interest in the Mahalo Gas Project from Comet Ridge. Santos has exercised this option prior to the option expiry date of 28 December 2022. The option is part of the loan-option arrangements put in place between Comet Ridge and Santos concurrent with Comet Ridge's purchase of APLNG's 30 per cent share of the Mahalo gas project, which was completed on 28 June 2022. The parties had two business weeks, as of the 26 September, to execute the Sale Agreement – which was prepared and agreed prior to execution of the loan-option agreements – to give effect to the transfer of the 12.86 per cent option interest. The effect of the option exercise on Comet Ridge includes the $13.15 million loan owing to Santos is reduced by $5.14 million to $8.01 million. Comet Ridge will subsequently repay the remaining $8.01 million to Santos. Additionally, no interest is payable by Comet Ridge to Santos on the $5.14 million portion of the loan. Santos has assumed liability for its pro-rata share of the $8 million deferred consideration payable to APLNG, being $3.43 million. The first $2 million tranche of deferred consideration is payable to APLNG on 28 June 2023 with Comet Ridge's share of that tranche now reduced to $1.4 million. Comet Ridge Managing Director Tor McCaul said that the company is pleased to see an early exercise of the new option to increase equity in the Mahalo gas project by Santos and to settle the loan agreements.

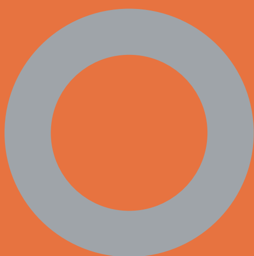
PREVIOUS HISTORY

29 August 2022: Comet Ridge has announced that gas production at Mahalo North 1 has exceeded 1.7 million cubic feet per day (MMcd). The measurement represents the highest recorded gas flow rate from a pilot well in the Mahalo Gas Hub area. The company is conducting ongoing work to develop an extensive geological model of the area. Currently Environmental field work and appraisal activities are ongoing to support the finalisation of a petroleum lease application by the end of the year. Production data from the site indicated a much larger area than originally mapped. Due to the size, future development wells could be further spaced, improving the economics of the project as it expands. Managing director for Comet Ridge Tor McCaul said that the impressive flow rates at Mahalo North is an outstanding result. "I can't remember the last time a single pilot production well in Queensland generated this sort of gas flow performance on its own," McCaul said. "We have also established a very large, sweet spot along the high productivity fairway, which also contains a third successful pilot well at Mahalo 7… our production wells will benefit from working in a group, rather than as a single pilot well which needs to drain a very large area," said McCaul.
15 August 2022: Comet Ridge announced that the Mahalo North 1 pilot well continues to record increases in gas production and is currently flowing at more than 1.25 MMcfd. This represents a 65 per cent improvement in flow rate over the past three weeks. The well's bottom hole pressure also continues to gradually decline each day whilst still being materially above the targeted level – which will replicate how the well would operate during long term production. This is a positive indicator for production wells in the area. Produced water is being maintained at approximately 1180 barrels of water per day of less. The data collected is providing firm technical information, enabling fine tuning and upgrading of development plans. "It's rewarding to see the well pass through the million cubic feet per day milestone and achieving additional gas on a daily basis. Apart from the flowrate, the ultimate volume of gas being accessed by this well is also a significant factor when considering development economics," McCaul said. "The large volume of water we have produced from this pilot suggests it is accessing a very large volume of gas."

NARRABRI GAS PROJECT

ONSHORE | IN PLANNING | PROPONENT: SANTOS

Santos
60 Flinders Street
Adelaide
South Australia 5000
P: (08) 8116 5000



OWNERSHIP
Santos 100%

SCOPE

The Narrabri gas project (PEL 238) hosts large resources of coal seam gas in two distinct and widespread coal measure sequences. A number of wells have been drilled and completed in the Bohena area, 25km southwest of Narrabri, with promising results. Early production results supported a production model interpretation of a major CSG province, with the potential for high (3-5 Bcf) recoverable reserves per well. ESG has signed a heads of agreement with APA Group regarding a new gas pipeline that could be built and connected to the Central West Pipeline for CSG delivery from the Narrabri area into the New South Wales gas market. Previously known as the Gunnedah Basin CSG project.

PREVIOUS HISTORY

August 2022: Santos has acquired the Hunter Gas Pipeline, which has planning approval for a pipeline from Wallumbilla in southern Queensland to Newcastle by way of Narrabri, in New South Wales. Construction of the pipeline is expected to commence in 2024.
May 2022: Santos managing director and CEO Kevin Gallagher delivered an address to the Australian Petroleum Production and Exploration Association (APPEA) annual conference in Brisbane, speaking on efforts to maintaining the momentum of the energy transition to decarbonisation without compromising energy security while working on the Narrabri Gas project. Gallagher also addressed the Global Energy Security Conference on natural gas in Seoul.
May 2022: A follow-up community consultive committee meeting was held on 17 May 2022 for the Narrabri project.
February 2022: A community consultive committee meeting was held on 15 February 2022 between Santos and GISERA to discuss the potential impacts of CSG depressurisation on GAB aquifers. Additionally, Santos provided a cooperate and developmental update on the progress of its permit approvals.
October 2021: The New South Wales Land and Environment Court has dismissed a legal challenge attempting to stop Santos from developing a $3.6 billion coal-seam gas project at Narrabri. The Mullaley Gas and Pipeline Accord launched an appeal against the Impending Planning Commission's decision last year Santos welcomes the new judicial review decision on the Narrabri Gas Project, saying it looks forward to getting on with work in regional New South Wales to drive investment and bring long-term energy security to the state.
November 2020: The Australian Government has approved Santos' proposal for the Narrabri gas project in New South Wales, with the company now set to embark on a 12-18 month appraisal program. Managing director and chief executive officer Kevin Gallagher said the conditions of the approval were consistent with those already set by the New South Wales Independent Planning Commission. Federal Environment Minister Sussan Ley said the announcement that the project had passed all environmental approvals meant that jobs and gas would soon start flowing.
September 2020: The New South Wales Independent Planning Commission (IPC) has approved Santos' Narrabri gas project due to its potential to improve Australia's east coast gas security and boost the state economy by delivering social benefits and ongoing employment opportunities. In making its determination, the IPC has relied on materials including a whole-of-government assessment conducted by the Department of Planning, Industry and Environment. However, the IPC has granted a phased approval that is subject to stringent conditions that Santos must meet before the project can progress to the next phase of development. The four phases include: phase one – appraisal; phase two – construction; phase three – production; phase four – rehabilitation.
July 2020: The Narrabri gas project has reached another milestone with the New South Wales Department of Planning, Industry and Environment endorsing the project and referring it to the Independent Planning Commission (IPC) for final approval. The Department of Planning, Industry and Environment concluded its assessment of the Narrabri gas project and referred the project to the IPC for public hearing and determination, recommending approval with strict conditions.

LEIGH CREEK ENERGY PROJECT

ONSHORE | GAS | UNDER CONSTRUCTION | PROPONENT: LEIGH CREEK ENERGY

NeuRizer
PO Box 12
Rundle Mall
Adelaide SA 5000
P: (08) 8132 9100

OWNERSHIP
Leigh Creek Energy 100%

SCOPE

The Leigh Creek Energy (LCK) project is located at Leigh Creek in central South Australia, 550 km north of Adelaide. It is proposed that commercial quantities of gas will be developed at the project for sale into the existing pipeline network. The project, which sits within the existing Leigh Creek coal mine area, will involve development of deep coal resources that are unable to be accessed by open-cut mining. Energy will be produced from coal using a process known as in-situ gasification (ISG). The process converts coal from its solid state into purely gaseous form, resulting in the production of methane or natural gas, along with other valuable gases such as hydrogen. Gas production from the project will be transported via a new pipeline, which will access the east coast gas network. Some gas produced will be used to create electricity on site for use within the project and for the town of Leigh Creek.

UPDATE

November 2022: NeuRizer has signed a binding take-or-pay offtake agreement with Korean company Daelim for the supply of 500,000 tonnes per year of urea. The estimated value of the contract is $1.5 billion. The SA government formalised the project's status as an impact assessed development (formerly known as major project status).

PREVIOUS HISTORY

24 March 2022: LCK appointed PricewaterhouseCoopers (PwC) as a strategic debt advisor. PwC was set to provide advice on securing further funding for the project, from the selection of an investment bank through to final statement. The company said it was in the process of producing an initial bankable feasibility study (BFS) for a carbon-neutral urea manufacturing facility at Leigh Creek. The completion of the initial BFS was due during the March 2022 quarter, with a final BFS due before the end of 2022.

22 March 2022: Preliminary site works for the Leigh Creek Urea Project (LCUP) has commenced, with geotechnical investigations for the construction of gasification wells and power generator areas already underway. In addition, as part of the federal government's Climate Active StandardIn March 2022, the company was certified carbon-neutral in March 2022. This award shows that they have achieved net zero carbon emissions across all business operations.

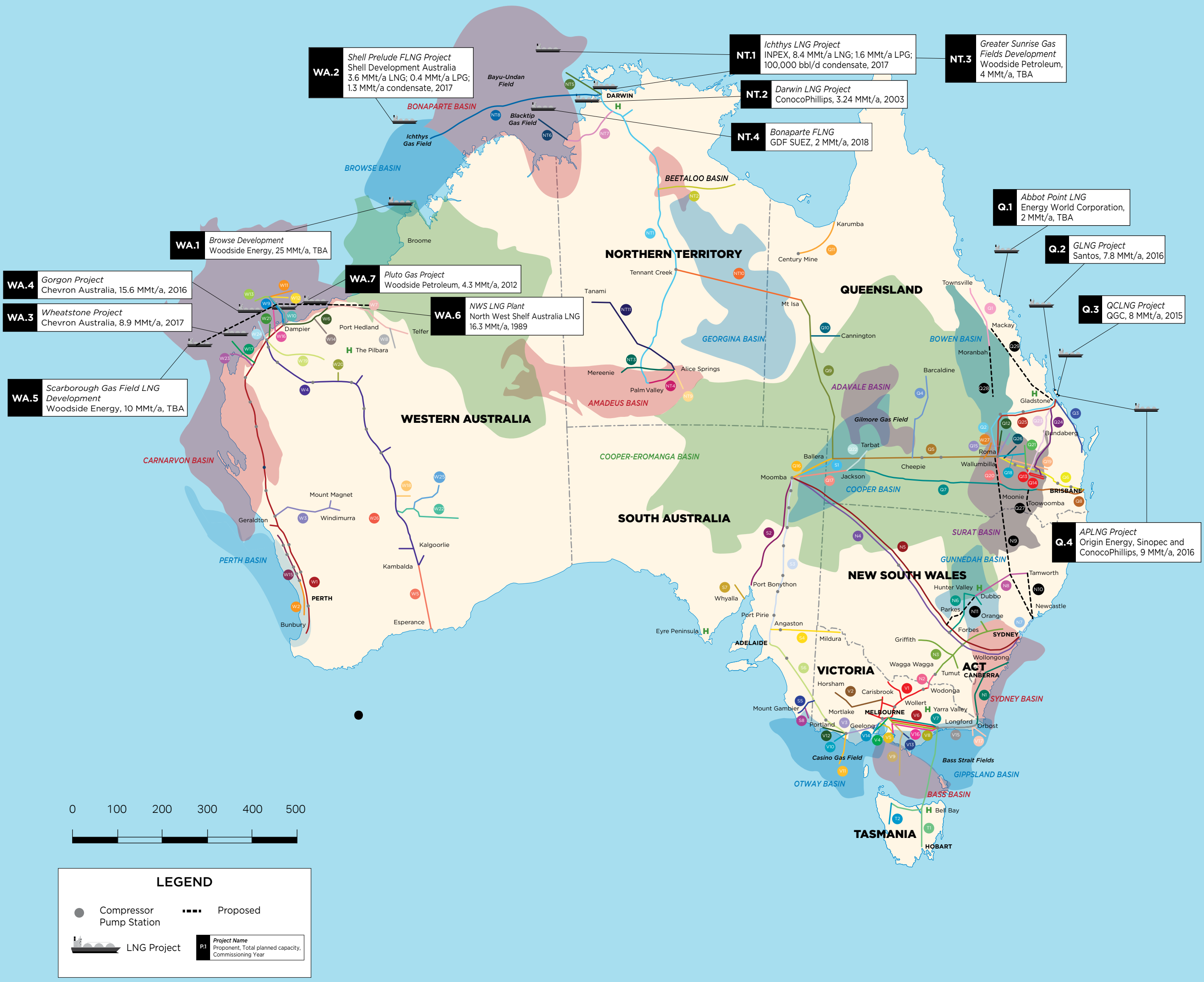
15 March 2022: NeuRizer (formally Leigh Creek Energy) has received formal activity notification from the South Australian Regulator, the Department for Energy and Mining (DEM), for the next stage of construction activity for the LCUP.

LCK managing director Phil Staveley said in accordance with the South Australian legislation the company has to seek approval from DEM prior to commencing work on site. "That approval was granted by the receipt of the activity notification. We now look forward to commencing the activities onsite. We expect preliminary, preparatory work to commence next week," he said.

The activity notification relates to shallow investigation drilling which will provide geological, geotechnical and environmental information for Stage 1 and Stage 2 design. As part of the work, it includes review of published geotechnical and geological information relevant to the site; shallow test pits, cone penetration testing, and shallow borehole drilling; and coordination of drilling contractors. In addition, environmental and geotechnical laboratory testing will also be undertaken, and assessments of all field and laboratory data and production of a conceptual geological and geotechnical ground model for the site.

February 2022: Leigh Creek Energy has completed its feasibility study for the LCUP potential for carbon capture and storage (CCS). Completed by engineering group inGauge, the study covered both engineering and geological sphered and confirmed that the LCUP has all the critical elements for large scale retention of CO_2 within an underground facility. This included reservoir presence and sufficient capacity, seal presence, seal thickness, seal integrity, injectivity, and sufficient depth. As a result, this proved that LCK has solved the CCS issue, with the next step for Daelim to incorporate the CCS plans into the front-end engineering and design (FEED) process.

PETROLEUM INFRASTRUCTURE OF AUSTRALIA



	NAME	OWNER	PRODUCT	LENGTH (km)
NT1	Amadeus Gas Pipeline	APA Group	Gas	1,658 km
NT2	Daly Waters - McArthur River Mine Gas Pipeline	Power and Water Corporation	Gas	330 km
NT3	Mereenie - Alice Springs Oil Pipeline (decommissioned)	Santos	Oil	270 km
NT4	Palm Valley - Alice Springs Pipeline	Australian Gas Networks	Gas	140 km
NT5	Bayu-Undan - Darwin Gas Pipeline	ConocoPhillips	Gas	502 km
NT6	Blacktip Gas Field Development	Eni Australia B.V.	Gas and Condensate	110 km
NT7	Bonaparte Gas Pipeline	Energy Infrastructure Investments	Gas	286 km
NT8	Ichthys Gas Export Pipeline	INPEX	Gas	890 km
NT9	Dingo Gas Field Pipeline	Central Petroleum	Gas	50 km
NT10	Northern Gas Pipeline	Jemena	Gas	622 km
NT11	Tanami Gas Pipeline	Australian Gas Infrastructure Group	Gas	440 km
N1	Eastern Gas Pipeline	Jemena	Gas	797 km
N2	Interconnect Pipeline Culcairn - Wodonga	APA Group	Gas	57 km
N3	Interconnect Pipeline Wagga Wagga - Culcairn	APA Group	Gas	88 km
N4	Moomba - Sydney Pipeline	APA Group	Gas	2,081 km
N5	Moomba - Sydney Ethane Pipeline	Ethane Pipeline Income Fund	Ethane	1,375 km
N6	Central West Pipeline	APA Group	Gas	255 km
N7	Sydney - Newcastle Liquids Pipeline	Caltex	Liquids	211 km
N8	Central Ranges Gas Pipeline	APA Group	Gas	294 km
N9	Queensland Hunter Gas Pipeline (P)	QHGP Pty Ltd	Gas	831km
N10	Liddell Gas Pipeline (P)	AGL Energy	Gas	76km
N11	Western Slopes Pipeline (P)	APA Group	Gas	450km
Q1	North Queensland Gas Pipeline	Palisade	Gas	391 km
Q2	Queensland Gas Pipeline	Jemena	Gas	629 km
Q3	Wide Bay Pipeline	Australian Gas Networks	Gas	274 km
Q4	Cheepie - Barcaldine Gas Pipeline	Ergon Energy	Gas	404 km
Q5	South West Queensland Pipeline	APA Group	Gas	937 km
Q6	Roma - Brisbane Pipeline	APA Group	Gas	438 km
Q7	Jackson - Moonie Pipeline (no longer in service)	Santos	Oil	797 km
Q8	Moonie - Brisbane Pipeline (no longer in service)	Santos	Oil	307 km
Q9	Carpentaria Gas Pipeline	APA Group	Gas	840 km
Q10	Cannington Lateral	APA Group	Gas	96 km
Q11	Century - Karumba Slurry Pipeline	MMG Century	Zinc and lead slurry	304 km
Q12	Comet Ridge - Wallumbilla Pipeline	Santos	Gas	127 km
Q13	Braemar 1 Pipeline	Alinta Energy Group	Gas	115 km
Q14	Braemar 2 Pipeline	ERM Power and Arrow Energy	Gas	110 km
Q15	Spring Gully - Wallumbilla Gas Pipeline	Jemena	Gas	87 km
Q16	QSN Link	APA Group	Gas	182 km
Q17	Jackson - Moomba Pipeline	Santos	Oil	273 km
Q18	Berwyndale to Wallumbilla Pipeline	APA Group	Gas	112 km
Q19	Darling Downs Pipeline	Jemena	Gas	292 km
Q20	Silver Springs to Wallumbilla Pipeline	AGL	Gas	101 km
Q21	Peat Lateral	APA Group	Gas	121 km
Q22	Tarbat - Jackson Pipeline	Santos	Oil	130 km
Q23	Australia Pacific LNG (APLNG) Pipeline	Origin Energy	Gas	530 km
Q24	Wallumbilla to Gladstone Pipeline (WGP) (formerly QCLNG) Pipeline	APA Group	Gas	540 km
Q25	GLNG Pipeline	Santos	Gas	435 km
Q26	Atlas Gas Pipeline	Jemena	Gas	60 km
Q27	Kenya to Goondiwindi Pipeline (P)	ERM Power	Gas	204km
Q28	Bowen Gas Pipeline (P)	Arrow Energy	Gas	200km
Q29	Arrow Bowen Pipeline (P)	Arrow Energy	Gas	430km
S1	Ballera - Moomba Pipeline	Santos	Raw Gas/Liquids	180 km

	NAME	OWNER	PRODUCT	LENGTH (km)
S2	Moomba - Port Bonython Pipeline	Santos	Oil/Condensate	659 km
S3	Moomba - Adelaide Pipeline System	QIC Global Infrastructure	Gas	1,184 km
S4	Angaston - Mildura Pipeline	Australian Gas Networks	Gas	379 km
S5	SESA Pipeline	APA Group	Gas	45 km
S6	SEA Gas Pipeline	APA Group (50%)/SEA Gas (50%)	Gas	680 km
S7	Whyalla Slurry Pipeline	OneSteel	Slurry	62 km
S8	South East Pipeline System	QIC Global Infrastructure	Gas	82 km
T1	Tasmania Gas Pipeline	Palisade Investment Partners	Gas	734 km
T2	Tasmanian Savage River Magnetite Slurry Line	Grange Resources Limited	Slurry	83 km
V1	Victorian Transmission System	APA Group	Gas	1,993 km
V2	Carisbrook - Horsham Pipeline	Gas Pipelines Victoria	Gas	183 km
V3	South West Pipeline	APA Group	Gas	144 km
V4	WAG Pipeline	Viva Energy Australia	Liquids	136 km
V5	Long Island - Altona Ethane Pipeline	Esso/BHP Billiton	Ethane	78 km
V6	Longford - Dandenong Pipeline	APA Group	Gas	174 km
V7	Longford - Long Island LPG Pipeline	Esso/BHP Billiton	LPG	188.3 km
V8	Longford - Long Island Point Oil Pipeline	Esso/BHP Billiton	Oil	185 km
V9	BassGas Pipeline	Origin Energy	Gas	215 km
V10	Casino Gas Pipeline	Santos	Gas	32 km
V11	Otway Gas Pipeline	Origin Energy	Gas	33 km
V12	Mortlake Gas Pipeline	SEA Gas (Mortlake)	Gas	83 km
V13	South Gippsland Natural Gas Pipeline	Duet Group	Gas	65.5 km
V14	Brooklyn to Corio Pipeline	APA Group	Gas	50.7 km
V15	Kipper Tuna Turrum Project	Esso Australia/BHP Billiton	Gas	34.8 km
V16	Longford Gas Conditioning Plant to Long Island Point Plant Replacement Pipeline	Esso/BHP Billiton	Oil	188.3 km
V17	Sole Gas Project	Cooper Energy	Gas	65 km
W1	Dampier - Bunbury Natural Gas Pipeline (DBNGP)	DBP	Gas	1,489 km
W2	Parmelia Gas Pipeline	APA Group	Gas	416 km
W3	Midwest Pipeline	APA Group/Horizon Power	Gas	364 km
W4	Goldfields Gas Pipeline	APA Group	Gas	1,378 km
W5	Kambalda - Esperance Gas Pipeline	Esperance Pipeline Company	Gas	342 km
W6	Pilbara Pipeline System	APA Group	Gas	219 km
W7	Port Hedland - Telfer Pipeline	Energy Infrastructure Investments	Gas	442 km
W8	Nifty Pipeline	Energy Infrastructure Investments	Gas	45 km
W9	North West Shelf Trunkline 1	North West Shelf Joint Venture	Gas and Condensate	134 km
W10	North West Shelf Trunkline 2	North West Shelf Joint Venture	Gas and Condensate	135 km
W11	Angel Export Pipeline (to North Rankin A)	North West Shelf Joint Venture	Gas and Condensate	49 km
W12	Wanaea/Cossack export line	CWLH Joint Venture	Oil	33 km
W13	Pluto Trunkline	Woodside Petroleum	Gas and Condensate	180 km
W14	Wodgina Lateral	APA Group	Gas	85 km
W15	Neerabup Pipeline	ERM Power and Energy Infrastructure Trust	Gas	30 km
W16	Reindeer Raw Gas Pipeline	Apache Energy	Gas	102 km
W17	Griffin/Tubridgi Pipeline (no longer in service)	Australian Gas Infrastructure Group	Gas	88 km
W18	Jaguar Lateral	Jabiru	Gas	33 km
W19	Fortescue River Gas Pipeline	DBP Development Group and TEC Pilbara	Gas	207 km
W20	West Angelas Pipeline	Rio Tinto	Gas	85 km
W21	Cape Preston Slurry Pipeline	CITIC Pacific	Slurry	25 km
W22	Eastern Goldfields Gas Pipeline	APA Group	Gas	293 km
W23	Macedon Gas Pipeline	BHP Billiton	Gas	67 km
W24	Wheatstone to Ashburton West Pipeline	Australian Gas Infrastructure Group	Gas	109 km
W25	Yamarna Gas Pipeline	APA Group	Gas	198 km

SHELL PRELUDE FLNG PROJECT

OFFSHORE | LNG | IN OPERATION | PROPONENT: SHELL AUSTRALIA

Shell Australia
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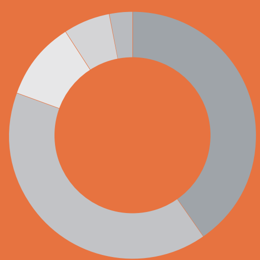
Perth WA 6000
P: (08) 9338 6600



FLNG STATS
Capacity: 3.6 MMt/a of LNG;
0.4 MM t/a of LPG;
1.3 MM t/a of gas condensate

OWNERSHIP
Shell 67.5%
INPEX 17.5%
KOGAS 10%
CPC 5%

SCOPE

Shell is developing the Prelude, Concerto and Crux gas fields, located in permits WA-44L and AC/L9 in Western Australia's offshore Browse Basin, using floating LNG (FLNG) technology. The Prelude FLNG facility is in the Browse Basin, approximately 475 km north-northeast of Broome and more than 200km from the nearest point on the coast of the Kimberley region in Western Australia. The hull of the facility was floated in late 2012, and is intended to remain over the Prelude field for 25 years, with the project designed to annually produce at least 3.6 MMt of LNG, 0.4 MMt of LPG and 1.3 MMt of gas condensate during that time. The FLNG facility is 488m long and 74 m wide, and when fully loaded weighs approximately 600,000 tonnes. Approximately 260,000 tonnes of that weight consists of steel. The facility includes six LNG storage tanks with a total capacity of 222,000 m3. Upstream facilities include seven wells, four flowlines approximately 3 km in length, umbilicals and flexible risers. The facility will be moored for the duration of operations by four groups of mooring chains in 250 m deep water.

PREVIOUS HISTORY

August 2022: Shell has reached an in-principal enterprise agreement with the Offshore Alliance around the industrial action on the floating liquified natural gas (FLNG) vessel, Prelude. As part of the agreement, changes are being made to workers' pay and rostering arrangements, improved job security and provisions for career progression. Shell has also agreed that the number of employees covered by the agreement will not be reduced by any increase of contractor or labour hire workers.

July 2022: Shell's FLNG vessel, Prelude has halted production due to work bans. While staff who are essential for maintaining the safety-critical functions are still aboard Prelude, all other workers will be demobilised while the ban is in effect. The industrial action has been undertaken in response to a proposed pay rise which was rejected by the workers after it was voted down by union members.

June 2022: Workers on Shell's Prelude floating liquefied natural gas (FLNG) facility began 12 days of industrial action over a pay fight in early June. The action came two months after Prelude resumed shipping LNG following a four-month long shut down due to major power failure. The purpose of the industrial action was to encourage Shell to prioritise hiring full-time Shell employees over contract workers.

January 2022: Shell's 'Prelude' floating LNG (FLNG) plant suffered a serious setback last month after it was ordered to halt production by the environmental regulator following a fire onboard. The facility was directed to stay offline until Shell can demonstrate adequate safety measures, which may require the removal of 1.5 million tonnes of production off the market through 2022. Shell must now prove to NOPSEMA that Prelude can safely recover from such power losses in the future before it can resume gas production. The company will develop a detailed plan and schedule to implement corrective actions and present them to the regulator.

December 2021: In early December 2021, a fire was reported onboard causing a complete power outage on the facility, which was hosting around 200 personnel. The incident prompted an onboard inspection and investigation by the National Offshore Petroleum Safety and Environmental Management Authority (NOPSEMA), which ordered the supermajority not to resume production. NOPSEMA has suggested a significant delay in the resumption of the plant in order to review the risks that could lead to a similar repeat incident.

March 2021: The production of Australian liquified natural gas (LNG) is expected to continue rising this year because of increased contributions from Prelude offshore Western Australia and east coast LNG producers. According to EnergyQuest's Energy Quarterly report 2021, LNG production will improve slightly this year to 80 million tonnes (Mt). The report outlined that Australia exported a record 78.2 Mt of LNG in 2020, up from 77.5 Mt in 2019. "This was a good result given the disruptions to Gorgon, the fact Prelude hadn't produced since early February, issues seen at Wheatstone with reduced production, and the COVID-19 destruction of LNG demand, particularly early in the year," the report highlighted.

SCARBOROUGH GAS FIELD

OFFSHORE | IN PLANNING | PROPONENT: WOODSIDE

Woodside Energy
11 Mount Street
Perth WA 6000
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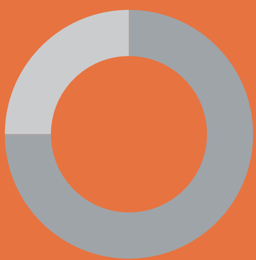


OWNERSHIP
Woodside 75%
BHP 25%

SCOPE

The Scarborough field is approximately 285 km offshore from the Pilbara town of Onslow in 900 m of water and is estimated to contain around 8–10 Tcf of gas. Woodside holds a 75 per cent interest in WA-1-5, and a 50 per cent interest in WA-62-R, WA-63-R and WA-61-R, covering the Scarborough, North Scarborough, Thebe and Jupiter gas fields respectively.
Woodside, as operator of the Scarborough joint venture with BHP (25 per cent), is proposing to develop the Scarborough gas resource through new offshore facilities connected by an 345 km pipeline to a proposed expansion of the existing Pluto LNG onshore facility (Pluto Train 2).
The proposal is to initially develop the Scarborough gas field with up to seven subsea, high-rate gas wells, tied back to a semi-submersible floating production unit (FPU) moored in 950 m of water close to the Scarborough field.

UPDATE

November 2022: Woodside has signed a memorandum of understanding (MoU) with the Japan Bank for International Cooperation (JBIC). The MoU focuses on identifying potential new energy products and lower-carbon, and LNG supply – including from Scarborough.

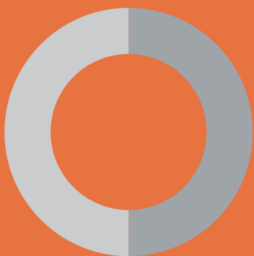
PREVIOUS HISTORY

August 2022: Woodside Energy has procured all major equipment for the Scarborough project. Development of the field will include 13 wells over its lifetime. Woodside is targeting the first LNG cargo in 2026.
June 2022: The Australian Conservation Foundation Incorporated (ACF) has commenced proceedings in the Federal Court of Australia in relation to the environmental assessment of Woodside's Scarborough Project. The ACF is seeking an injunction to restrain offshore project activities. However, the Scarborough Project has been the subject of rigorous environmental assessments by a range of regulators including the National Offshore Petroleum Safety and Environmental Management Authority, the Commonwealth Department of Agriculture, Water and the Environment and the Western Australian Environmental Protection Authority. Woodside CEO Meg O'Neill said the Scarborough Project is underway and proceeding to schedule after receiving all primary environmental approvals. "The project will deliver significant local and national benefits in the form of employment, tax revenue and reliable gas supply in the energy transition for decades to come," she said. "Woodside will vigorously defend its position in these proceedings."
April 2022: Woodside received key approvals for the execution of the Scarborough project. The Scarborough JV has received an offer for the pipeline licence to construct and operate the Scarborough pipeline in Commonwealth waters. Approval has also been granted for the Scarborough Field Development Plan (FDP), enabling Woodside to begin petroleum recovery operations from petroleum production licences WA-61-L and WA-62-L.
11 January 2022: Saipem has received the notice to proceed from Woodside to complete the export trunkline coating and installation of the pipeline that will connect the Scarborough gas field with the onshore plant. The company was awarded the contract to operate on behalf of the Scarborough joint venture (JV) to develop new offshore facilities connected by a 430 km export trunkline. With a 36-inch/32-inch diameter, the pipe will connect to a second LNG train (Pluto Train 2) at the existing Pluto LNG onshore facility. According to Saipem, the development will be among the lowest carbon intensity sources of LNG globally. The first cargo from Scarborough is expected to be delivered in 2026.

WEST ERREGULLA (EP 469)

OFFSHORE | IN DEVELOPMENT | PROPONENT: STRIKE ENERGY

Strike Energy
1/31-35 George Street
Thebarton SA 5031
P: (08) 7099 7464



OWNERSHIP
Strike Energy 50%
Warrego Energy 50%

SCOPE

Located in the EP 469 licence area, the West Erregulla prospect has a best total prospective resource estimate of 32.8 billion m3 of gas. Strike (operator) and Warrego both hold a 50 per cent interest in the acreage and are advancing the prospect in order to produce a new source of gas for Australia's gas market.

PREVIOUS HISTORY

29 August 2022: Strike has completed testing activities at West Erregulla-3 and the results are favourable. The well was stable for the duration of the five-hour high-rate test which was constrained by well testing equipment. It was recorded at 83 mmscf/d with a flowing well head pressure of 3474 psi on a 68/64-inch choke. Well head pressure at West Erregulla-3 returned to virgin levels after just three hours. The gas was observed to be of low impurity dry gas, in line with other gas compositions from the field and the region at large.
23 August 2022: Strike has been testing the producibility from the 40 m of perforations across the Kingia Sandstone reservoir from the 4733 m measured depth in the West Erregulla-3 well. Testing to date has produced a choke coefficient peak rate of 90 mmscfd, at a flowing well head pressure of 3020 psi on a 76/64 choke. No sand or formation water has been observed during the test so far, and the gas stream produced from the Kingia Sandstone is a low impurity dry gas.
July 2022: Strike Energy's West Erregulla gas field has completed its independent reserves and resources review post the drilling at West Erregulla-3. This review has yielded a substantial 41 per cent increase in the quantity of gross 2p sales gas estimated for the field of 422 PJ and a gross 2C contingent resource of 30 PJ. This considerable low-cost energy and endowment will be used in part to support the company's move to vertically integrate into fertiliser manufacturing.
5 July 2022: Strike Energy has commenced drilling a 6-inch hole at its West Erregulla-3 and has subsequently drilled through the Irwin River Coal Measures, then through the primary objective in the Kingia Sandstone. The latter was observed at a total of 4737 m measured depth. As seen throughout the field, the Kingia Sandstone was observed to be made up of packages of blocky, clean sands which indicate conventional reservoir potential on the logging while drilling (LWD) tools. Elevated mud gas readings were also observed as the section was drilled which has also been interpreted on the LWD data. Strike has subsequently drilled into the Bit Basher Shale to a depth of 4806 m MD before pulling out of the hole to perform a drill bit change. Strike is running back in with a new drilling assembly to drill the well to final depth. Moving forward, Strike will drill the well to a final depth which is anticipated to pass through the secondary objective in the High Cliff Sandstones. Strike will then condition the hole before running a wireline campaign to confirm the results of the various objectives and collect any samples and pressure data. Strike intends to provide an update on the results of the well once the data acquisition campaign is complete.
20 June 2022: Strike Energy has drilled through the existing cement plugs and through the Carynginia Shale and into the Irwin River Coal Measures at the West Erregulla-3 (WE-3) appraisal well. As seen in late 2020, the Carynginia Shale was heavily over-pressure and caused the initial WE-3 well to be suspended in January 2021. The WE-3 well was redesigned to better cope with the mud weight and gas pressure issues at greater depths.
8 June 2022: The West Erregulla-3 (WE-3) appraisal well was successfully re-entered on 2 June 2022 using the Ensign 970 drilling rig. The initial WE-3 well was suspended in January 2021 after encountering abnormally overpressure gas in the Carynginia Formation. The WE-3 well has since been redesigned to better cope with mud weight and gas pressures at greater depths. The Ensign 970 drilling rig has been fitted with a Weatherford Managed Pressure Drilling (MPD) system to ensure well pressure remains within operational limits.

GORGON PROJECT

ONSHORE | LNG | IN OPERATION | PROPONENT: CHEVRON

Chevron
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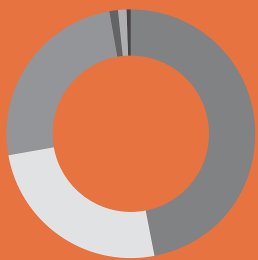

OWNERSHIP
Chevron 47.3%
ExxonMobil 25%
Shell 25%
Osaka Gas 1.25%
Tokyo Gas 1%
JERA 0.417%

SCOPE

The Greater Gorgon development plan is based on the installation of a subsea gathering system and pipelines from the Gorgon and Jansz fields to Barrow Island. Three 5 MMt/a LNG trains are located on the central-east coast of Barrow Island. Reservoir carbon dioxide will be removed and reinjected into deep saline reservoirs beneath the island. LNG is shipped to international markets, while compressed domestic gas is delivered via a 90 km subsea pipeline to the Western Australian mainland, interconnecting with the Dampier to Bunbury Natural Gas Pipeline.

PREVIOUS HISTORY

July 2022: Gorgon stage 2 is expected to deliver gas in September. Chevron continues to focus on incremental capacity increases at Gorgon to eventually increase nameplate capacity. The Gorgon CCS project has successfully stored about 6.6 million tonnes of CO_2. Gorgon and Wheatstone shipped 87 LNG cargoes this year.
June 2022: Chevron has granted Worley a 10-year global master services agreement to provide services to Chevron's upstream, midstream and downstream assets including project development for onshore and offshore assets. Under the agreement, Worley will provide engineering and project related services. This includes working alongside Chevron's digital enablement specialists in a bid to optimise ways of working and improve overall efficiencies within the company.
April 2022: Chevron Australia's environment plan for the activities associated with the commissioning, start-up and operation of the Gorgon and Jansz feed gas pipeline and wells offshore WA has been approved. Outlined in its environment plan to NOPSEMA, the Jansz–Io gas fields are located within production licenses WA36L, WA39L and WA40L 200 km off the north-west coast of Western Australia in water depths of 1350 m. The pipelines are located in Commonwealth Waters within pipeline licences WA19PL and WA20PL. The initial field development comprised of wells and subsea infrastructure, including the feed gas pipeline, associated with the Gorgon Foundation Project, which was commissioned in 2015. This field development is being supplemented by Gorgon Stage 2 (GS2), which comprises additional wells and subsea infrastructure within the Gorgon and Jansz-Io gas fields. Operations of the Gorgon Gas Development is expected to continue for the nominal operational design life of 50 years.
February 2022: EnerMech has secured $USD100 million ($139 million) of pre-commissioning and new pipeline contract awards, following a $USD30 million equipment investment program across its global locations to support its growth in the resources industry. As part of the new contracts is a five-year project with Chevron Australia to deliver its integrated services to the operator's western oil and gas assets which started in 2021. The work scope includes specialised cleaning, nitrogen purging and process plant drying, integrity leak and pressure testing, hydraulic hose integrity management and specialist hydraulic services.
August 2021: The national petroleum regulator is assessing Chevron Australia's environment plan for the activities associated with the commissioning, start-up and operation of the Gorgon and Jansz feed gas pipeline and wells offshore WA. Chevron reported that the wells associated with the plan are located in WA36L, WA37L, WA38L and WA39L.
The pipelines are located in Commonwealth Waters within pipeline licences WA19PL and WA20PL. The initial field development comprised of wells and subsea infrastructure, including the feed gas pipeline, associated with the Gorgon Foundation Project, which was commissioned in 2015. This field development is being supplemented by Gorgon Stage 2 (GS2), which comprises additional wells and subsea infrastructure within the Gorgon and Jansz-Io gas fields.

DORADO OIL FIELD PIPELINE

OFFSHORE | OIL | FEED | PROPONENT: SANTOS

Santos
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Adelaide
South Australia 5000
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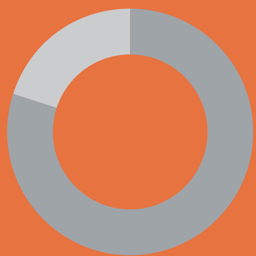

OWNERSHIP
Santos 80%
Carnarvon Petroleum 20%

SCOPE

The Dorado oil field is in the Bedout Basin, approximately 150 km north of Port Hedland in Petroleum permit WA-437-P. The project will be developed jointly in line with the equity split between Santos (80 per cent) and Carnarvon Petroleum (20 per cent). The offshore resource is expected to be developed with up to 16 platform wells drilled by a jack-up drilling rig. These would be connected back to an adjacent floating production, storage and offloading facility (FPSO) moored in 95 m of water above the Dorado field. The proposed FPSO unit will have processing facilities to stabilise and store the oil and compress and re-inject gas to the reservoir. Santos anticipates that the development will have an estimated 10-15 years oil life. A front-end engineering design (FEED) decision is targeted for 2020, followed by a final investment decision (FID) in 2021 and production ready for start up (RFSU) some four years later.

PREVIOUS HISTORY

August 2022: Carnarvon Petroleum managing director and CEO Adrian Cook has announced that the FEED process for the Dorado development is substantially complete. While the development is close to being financial investment decision (FID) ready, it still requires the finalisation of the engineering procurement and construction (EPC) contract for the floating production storage and offloading (FPSO) vessel. Procurement of the contract has been impeded by an unstable cost environment and it requires more certainty around the capacity of the supply chain for the development. "The Dorado development is occurring within production license WA-64-L…That said, given the current regional inflationary pressures and supply chain challenges, the risk of cost escalation is unacceptable high and requires fiscal discipline until this environment shows signs of stabilising," said Cook. The engineering work for the well head platform and FPSO is essentially complete.
May 2022: The large quantity of light oil at the Pavo-1 well will be a key factor in mobilising the Dorado project, Carnarvon Energy announced. An estimated 43 million barrels (gross) of oil are present at Pavo-1, with the another 55 million barrels in prospective resources. This represents a promising step toward the development of the Dorado facilities, which will be located approximately 46 kilometres west of the Pavo structure. The Dorado production facilities will be designed to handle rates of up to 100,000 barrels of oil per day. These rates are expected to decline after a one-to-two-year plateau, allowing for back-fill from new fields such as Pavo. Delivering resources from the Pavo field will increase the efficiency of the Dorado facility and extend the period of time the project can produce at capacity.
April 2022: The National Offshore Petroleum Titles Administrator (NOPTA) has agreed to grant the joint venture a life-of-field production licence (PL) for the four blocks containing the Dorado field. The joint venture, consisting of Carnarvon Energy and Santos, has accepted the PL offer, with a PL to be granted by NOPTA shortly. Once granted, the PL enables the joint venture to produce petroleum from the licence area, as well as continue to explore and appraise any additional petroleum within the WA-437-P exploration permit.
March 2022: Carnarvon Energy has reported that design and engineering work for the production facilities for the Dorado Phase 1 liquids development continues to progress as expected. Engineering and subsurface studies have confirmed the project will initially produce between 75,000 and 100,000 barrels of oil per day (bopd). Studies have also confirmed that associated gas can effectively be re-injected into the Dorado reservoirs to maintain pressure, thereby maintaining strong production rates. Final capital cost definition is being undertaken as pard of the FEED process and will be finalised ahead of a FID. It is anticipated the Dorado project will be FID-ready by mid-2022.
September 2021: Sembcorp Marine Rigs & Floaters has also secured a contract from Altera Infrastructure to undertake the FEED work for the FPSO facility at Dorado. Santos also awarded Atteris the subsea FEED contract for the project.

CLIFF HEAD OIL FIELD

OFFSHORE | OIL | IN OPERATION | PROPONENT: TRIANGLE ENERGY

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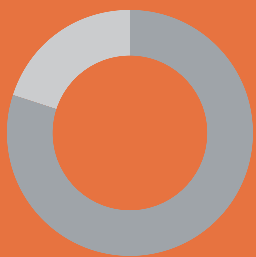

OWNERSHIP
Triangle Energy 78.75%
Royal Energy 21.25%

SCOPE

Cliff Head was the first commercial oil discovery developed in the offshore Perth Basin.
The development cost of the field was $327 million with first oil production commencing in May 2006. Triangle Energy now holds 78.75 per cent interest in Cliff Head and is the operator, with Royal Energy holding an interest of 21.25 per cent.

UPDATES

October 2022: Pilot Energy and Triangle Energy have formalised the restructure of the Cliff Head Joint Venture. Under the agreement, Pilot will have a 60 per cent interest in the Cliff Head oilfield and the future planned Cliff Head CCS project, with Triangle retaining the remaining 40 per cent.
August 2022: With the trucking of 26,500 barrels of oil to complete a 51,000-barrel cargo aimed for Thailand, the Cliff Head Joint Venture have demonstrated a viable export route for the Cliff Head oilfield and the rest of the Perth Basin.

PREVIOUS HISTORY

July 2022: Triangle Energy and Pilot Energy have announced the establishment of a new tanker export route as part of the Cliff Head Joint Venture (CHJV). The new Geralton-Singapore tanker export route is a major milestone for Cliff Head oil export. The CHJV has completed its first load-out of 24,500 barrels of oil onto a chartered tanker, the AB Paloma, between the 8 and 11 July 2022. While the initial load-out came from the recently expanded Arrowsmith Stabilisation Plant (ASP), the AB Paloma will remain on standby to be loaded with a further 25,000 - 30,000 barrels to be produced and stored by CHJV. The cargo will then be sent to Singapore to be sold.
June 2022: The Cliff Head joint venture (JV) has announced that the final lifting of oil from the Kwinana Oil Terminal to BP Singapore was undertaken on 8 May 2022.
The final lifting comprised of 139,992 barrels sold at $US105.2 ($146) and the tank bottoms of 88287 barrels sold at October's price of $US75.70 ($105).
The Cliff Head JV will receive a total income of just under $US15.5 million. The income will be effectively allocated to the JV partners with Triangle Energy set to receive approximately $16.8 million of the revenue and Pilot Energy to receive around $4.5 million.
Presently, the Cliff Head oil field is continuing production with the oil being stored in the newly refurbished tanks at the Arrowsmith facilities. Once the tanks are full, the oil will be trucked to the Port of Geraldton for loading into a tanker chartered by the Cliff Head JV.
"I am pleased to report to shareholders that The Cliff Head Joint Venture has completed a significant value oil sale, taking full advantage of the current high oil prices. This will allow the Cliff Head Joint Venture to progress our exploration and production activities at Cliff Head, including the upcoming workover of the CH 10 well," Managing director of Triangle, Conrad Todd said.
April 2022: Pilot Energy and Triangle Energy reached an agreement on the key principles to restructure the existing joint venture ownership arrangements for the Cliff Head joint venture (CHJV) and the proposed Cliff Head carbon capture and storage (CCS) project. At the end of March Pilot announced it had been undertaking feasibility studies into the potential for carbon capture and storage and blue hydrogen production focussed on the Cliff Head oil field, which has confirmed a significant CCS resource in WA-31-L. The binding Cliff Head re-alignment term sheet paves the way for Pilot and Triangle to progress an application to the National Offshore Petroleum Titles Administrator (NOPTA) to have the Cliff Head Oil Field reservoir declared a Greenhouse Gas Storage formation and to pursue the Cliff Head CCS project once economic oil production has finished. Following a declaration, the CHJV anticipates making an application to NOPTA for the grant of a Greenhouse Gas Injection Licence for the injection and permanent sequestration of a minimum of 500,000 tonnes of CO_2 per annum into the Cliff Head Oil Field reservoir. Receipt of this Injection Licence will enable the CHJV to commence the implementation of the Cliff Head CCS project with the project anticipated to be operational by 2025.

ICHTHYS LNG PROJECT

OFFSHORE | LNG | IN OPERATION | PROPONENT: INPEX

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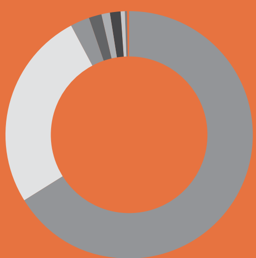

OWNERSHIP
INPEX 66.245%, operator
Total 26%
CPC Corporation Taiwan 2.625%
Tokyo Gas 1.575%
Osaka Gas 1.2%
Kansai Electric Power 1.2%
JERA 0.735%
Too Gas 0.42%

SCOPE

The Ichthys Gas Field is in permit WA-285-P in the Browse Basin, approximately 200 km offshore northwest Australia. Reserves for the project stand at 12.8 Tcf of gas and 527 MMbbl of condensate. The project is initially expected to produce 8.4 MMt/a of LNG, 1.6 MMt/a of LPG and 100,000 bbl/d of condensate. INPEX's proposed development includes offshore processing facilities and condensate storage, and an 885 km pipeline from the field to the onshore processing facility at Blaydin Point on the Middle Arm Peninsula, Darwin.

UPDATE

October 2022: Hard work at the INPEX-operated project has paid off with the departure of Ichthys LNG's 750th export cargo. Ichthys LNG is a joint venture (JV) between INPEX group companies – operator for the project – as well as major partner TotalEnergies and the Australian subsidiaries of CPC Corporation which include Tokyo Gas, Osaka Gas, Kansai Electric Power, JERA and Toho Gas. In a LinkedIn post announcing the achievement, INPEX cited the milestone as being testament to the hard work and tenacity of its teams, as well as a commitment to safe and stable production. The cargo was exported from the onshore facility at Bladin Point, near Darwin, where gas from the Ichthys field is cooled and transformed into liquid.

PREVIOUS HISTORY

June 2022: The National Offshore Petroleum Safety and Environmental Management Authority (NOPSEMA) has approved operations for INPEX's Ichthys project. Commonwealth approval to develop the Ichthys Field in the Browse Basin was acquired in 2011. This development included the installation and operation of the offshore infrastructure for the 40-year field life. INPEX'S environmental plan (EP) for the project, submitted by INPEX in August 2021, is the first five-year revision of project's the operation. Now that it has been approved by NOPSEMA, it will cover the next five years of the expected 40-year life of the Ichthys field. It will also allow periodic shutdowns to occur so that new equipment and infrastructure can be installed.

May 2022: The National Offshore Petroleum Safety and Environmental Management Authority (NOPSEMA) has approved INPEX's environmental plan (EP) for the Ichthys project, allowing the offshore facility to continue its operations and conduct maintenance activities. The EP, which was submitted by INPEX in August 2021, is the first five-year revision of project's the operation. Now that it has been approved by NOPSEMA, it will cover the next five years of the expected 40-year life of the Ichthys field. It will also allow periodic shutdowns to occur so that new equipment and infrastructure can be installed. Maintenance is currently scheduled for the 2022-23 period and will include the insertion of an inline pigging tool to assess the internal wall of the GEP. These works are expected to last for at least seven days.

February 2022: Altrad has been awarded a contract from INPEX to perform coating and insulation work at Ichthys LNG onshore processing facilities at Bladin Point in Darwin. The scope of services under the contract includes work pack preparation, planning, coordination, supervision, provision of access and execution of coating and insulation works. The contract is for four years and provides the opportunity for local employment for more than 150 persons. "Altrad Services is proud to have supported Ichthys LNG since 2019 and this contract award reinforces its strong relationship with INPEX and testament to Altrad's high quality, safety and execution capabilities," a spokesperson for Altrad said.

September 2021: The national petroleum offshore regulator is assessing INPEX's environment plan (EP) for Ichthys Field development in WA-50-L, offshore Western Australia, for plans to insert an inline piping tool to assess the internal walls of the gas export pipeline (GEP). As part of planned maintenance and coinciding with a major shutdown, INPEX plans to insert an inline pigging tool to assess the internal wall of the GEP. This activity will involve the use of a vessel to lower a pig launcher receiver (PLR) which will be attached at the gas export riser base (GERB) located in WA-50-L. Once installed, the PLR pushes the pig from offshore along the length of the GEP to the Ichthys LNG onshore plant and is currently scheduled for the 2022-23 period and is expected to last for at least seven days. The PLR will remain in-situ and be recovered from the GERB during the scheduled 2024 shutdown.

PLUTO GAS PROJECT

ONSHORE & OFFSHORE | PIPELINE | IN OPERATION | PROPONENT: WOODISDE

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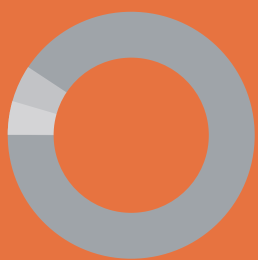
WA 6000
P: (08) 9348 4000



OWNERSHIP
Woodside: 90%
Kansai Electric: 5%
Tokyo Gas: 5%

SCOPE

The Pluto and Xena gas fields, located approximately 190 km northwest of Karratha in Western Australia, together hold an estimated 5 Tcf of dry recoverable gas. The initial project phase includes a single LNG production train at the Burrup LNG Park with forecast production of 4.3 MMt/a of LNG. The train will be connected via a 180 km, 914 mm offshore pipeline to a platform in 85 m of water, which in turn will be connected to five subsea big bore wells on the Pluto field. The LNG train is being built in modular form in Thailand and shipped to the site as 264 modules. A second and third LNG train are expected to be added, in addition to a domestic gas facility for the Western Australian market. Final investment decisions on the two additional trains are targeted by end 2010 and end 2011 respectively. First gas from the field is expected in late 2010 and first LNG in early 2011. The project is underpinned by 15-year sales agreements with Kansai Electric and Tokyo Gas for up to 3.75 MMt/a of LNG. Both companies became project participants in January 2008, each acquiring a 5 per cent interest in the foundation project. With the construction of the foundation project progressing, Woodside has commenced front-end engineering and design (FEED) for the second and third LNG trains.

UPDATES

October 2022: Woodside has announced that the Scarborough and Pluto Train 2 projects are on schedule to have first LNG cargo in 2026. Construction of the village in Karratha – built to accommodate working crews for the construction of the Pluto Train 2 project – has been completed. Additionally, fabrication of the subsea flowlines for the development of Scarborough commenced in August. "Overall, the Scarborough and Pluto Train 2 projects combined were 21 per cent complete at the end of the quarter and remain on track for targeted first LNG cargo in 2026," said CEO Meg O'Neill. Woodside said that the combined Scarborough and Pluto 2 projects are 21 per cent complete.

27 September 2022: The Pluto Train 2 project will have its medical needs met by Australian company Aspen Medical. Construction of a second LNG train for the project will occur at the Pluto LNG onshore facility – operated by Woodside Energy – in Karratha, WA. Aspen Medical was chosen after a highly competitive tender process. The company's international business development manager Greg Levin said that the company specialises in the provision of healthcare in challenging environments. "We would like to thank Bechtel for entrusting our team with the provision of medical services for the Pluto Train 2 Project… we are looking forward to supporting the health and wellbeing of those involved in this project," Levin said. The job requires Aspen to manage two medical clinics for the project, one located at the construction site and the other at the camp/village site. The sites will be fully staffed with a mix of doctors, registered nurses and nurse practitioners, paramedics, physiotherapists and administration support.

PREVIOUS HISTORY

September 2022: Bechtel has started construction on Woodside Energy's second LNG train, Pluto Train 2, at the Pluto liquefied natural gas (LNG) onshore facility on the Burrup Peninsula, near Karratha, in WA. Estimated to cost $5.6 billion, the Pluto Train 2 project will be equipped to process gas from the Scarborough development in WA. Bechtel is serving as the engineering, procurement, and construction contractor for the Pluto Train 2 project, which will have an LNG capacity of approximately five Mtpa. Woodside Energy's CEO Meg O'Neill said that the company is increasing its activities at the Pluto Train 2 project in WA. "With all major equipment items procured, fabrication of the floating production unit topsides and Pluto Train 2 construction works underway, the subsea trees for the initial development phase complete and pipeline manufacturing progressing,' said O'Neill.

BAROSSA OFFSHORE PROJECT

OFFSHORE | GAS LNG | IN PLANNING | PROPONENT: SANTOS

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60 Flinders Street
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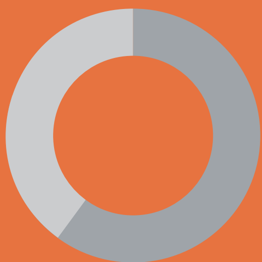

OWNERSHIP
Santos 62%
SK E&S 37.5%

SCOPE

The Barossa Joint Venture, comprised of Santos as operator and SK E&S Australia, is progressing the Barossa offshore gas and light condensate project. A final investment decision to go-ahead with the project has now been made. The project will provide a new source of gas to the existing Darwin LNG facility, subject to suitable commercial arrangements being put in place. It will backfill the facility once the existing offshore gas supply from the Bayu-Undan offshore field has been exhausted. Development of the large, discovered Barossa resource will extend the operating life of DLNG for an additional 15-20 years. The Barossa field sits within Santos' northern Australia portfolio, one of the company's core long-life, natural gas asset regions, and encompasses petroleum permit NT/RL5 located in Commonwealth waters, 300 kilometres north of Darwin, offshore Northern Territory. The project comprises a Floating Production Storage and Offloading (FPSO) facility, subsea production system, supporting in-field subsea infrastructure and a gas export pipeline.

UPDATE

October 2022: Barossa drilling operations suspended following the Federal Court's decision to set aside the acceptance by the regulator of the drilling and completion activities environmental plan. Santos is appealing the decision with a hearing on the appeal expected to be held in mid-November.

PREVIOUS HISTORY

August 2022: As operator of the Barossa joint venture, Santos has announced that the final investment decision (FID) has been made to undertake the Darwin pipeline duplication project. The project will see the Barossa gas export pipeline to Santos' Darwin liquified natural gas (LNG) facility extended. It will also allow the existing Bayu-Undan to Darwin pipeline used to facilitate future carbon capture and storage (CCS) options. This development comes after Santos proposed a revision to the environment plan for the Darwin export gas pipeline.

May 2022: JERA, a subsidiary of Tokyo Electric Power Group and Chubu Electric Power Group, has secured the 12.5 per cent sale in the Barossa project from Santos. The sale saw Santos receive $US327 million (over $462 million) in cash proceeds. The project's participants now include Santos (50 per cent), SK E&S (37.5 per cent) and JERA (12.5 per cent). The Barossa project was around 33 per cent complete at the time of sale and remains on schedule for production to commence in 2025.

March 2022: The national petroleum regulator has approved Santos' Barossa Development for its plans to commence a drilling and well campaign in the second quarter of 2022.
The company advised that, as part of the approved development, it wants to begin the petroleum activity in production licence NT/L1. Outlined in the company's environment plan, six subsea production wells are planned to be drilled and completed around the future locations of three subsea production manifolds, with two wellheads adjacent to each manifold. If required, up to two contingency production wells could be drilled and completed at any manifold (eight wells in total).

21 December 2021: The national petroleum regulator has approved Santos' Barossa Development for its plans to commence a drilling and well campaign in the second quarter of 2022. The company advised that, as part of the approved development, it wants to begin the petroleum activity in production licence NT/L1. Outlined in the company's environment plan, six subsea production wells are planned to be drilled and completed around the future locations of three subsea production manifolds, with two wellheads adjacent to each manifold. If required, up to two contingency production wells could be drilled and completed at any manifold (eight wells in total).

9 December 2021: Santos has agreed to the sale of 12.5 per cent interest to JERA in the Barossa project, to be complete in the first half of 2022. When the sale is complete, JERA will reimburse Santos for its share of capital expenditure on the project from the start date to finish. The total consideration due to Santos at completion is expected to be around US$300 million ($AUD418.91 million). When completed, the participants in the Barossa project will be Santos with 50 per cent, SK E&S with 37.5 per cent and JERA with 12.5 per cent.

ENFIELD OIL FIELD DEVELOPMENT

OFFSHORE | FPSO | IN PRODUCTION | PROPONENT: WOODSIDE

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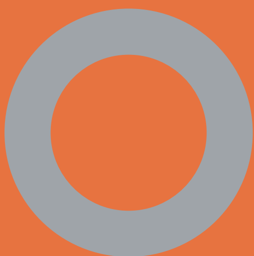

OWNERSHIP
Woodside Energy: 100%

SCOPE

The Enfield project is located in permit WA-271-P, about 40 km northwest of the North West Shelf in Western Australia. Enfield has reserves of more than 125 MMbbl of oil. The development includes five production wells and six water injection wells for reservoir pressure support, with flowlines to a disconnectable floating production, storage and offloading (FPSO) vessel moored over the field in approximately 400 ms of water. The FPSO vessel is a double-hull Suezmax-type trading tanker with topsides of 8,000 tonnes. The vessel has a dead weight of about 150,000 tonnes and will be about 270 m long, with a storage capacity of 900,000 bbl.

PREVIOUS HISTORY

March 2022: Woodside Energy has awarded DOF Subsea Australia an offshore support services contract for the Enfield XT Retrieval. The campaign execution will involve the recovery of 18 Subsea XTrees, 18 Flowbases and associated spool sections, one wellhead severance and recovery of up to 18 temporary guide bases at the Enfield Field, Australia. The contract includes project management, engineering, fabrication, and decommissioning services and is expected to be undertaken in the third quarter and fourth quarter 2022, using DOF Subsea's MPSV Skandi Hercules.

June 2021: Woodside's proposal to permanently plug and abandon 18 wells, within permit area WA-28-L in Western Australia, is being assessed by the national offshore petroleum regulator. The petroleum activates outlined in its environment plan (EP) include production, water injection and gas injection wells, and remove well infrastructure above mudline (Xmas trees, flowline support bases, wellheads, temporary guide bases, ancillary equipment).

The proposed petroleum activities program is scheduled to occur between the first quarter of 2020 and the fourth quarter of 2024.

Woodside advised that once accepted, this EP will cover ongoing management of the Enfield wells until permanent plugging and abandonment activities are complete, including inspection, monitoring, maintenance and repair (IMMR) activities.

These activities were previously covered under the Nganhurra operations cessation environment plan, accepted by NOPSEMA on February 5, 2021.

The company outlined that if this EP is accepted by NOPSEMA while an IMMR campaign is in progress, the activity will continue to be covered under the previous Nganhurra operations cessation environment plan until completion.

August 2019: The oil was produced through the Ngujima-Yin floating production storage and offloading vessel (FPSO), which is located over the Vincent field. CEO Peter Coleman said getting the project, which was approved in 2016, to this point on schedule and under budget was a significant achievement. "A highlight included performing over five million work hours in the shipyard without a recordable safety incident," he said. "The technical and project leadership capabilities applied on the Greater Enfield Project will be carried forward as we progress our plans to develop the Scarborough and Browse offshore gas resources through the proposed Burrup Hub."

PAPUA LNG PROJECT

ONSHORE | LNG | IN PLANNING | PROPONENT: TOTAL S.A.

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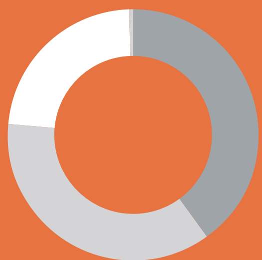

OWNERSHIP
Total 40%
ExxonMobil 36.5%
Oil Search 22.8%
Minorities 0.5%

SCOPE

The Papua LNG project will encompass two LNG trains of 2.7 Mt/a each and will be developed in synergy with the existing PNG LNG project facilities. Under the initial concept, one of the processing trains would be supplied partly by gas from Exxon-operated assets that feed the existing PNG LNG project. Two additional trains would be fed from the Elk-Antelope gas fields, which are part of the separate Total-led project called Papua LNG. According to Total, production should begin by 2024.

UPDATE

October 2022: Strong production at PNG LNG was maintained during the third quarter with the plant operating at an annualised rate of 8.6 mtpa. The project shipped 29 cargoes in the quarter, including one (JKM-priced) spot cargo. Record gas export rates were achieved from the Santos-operated Gobe and Kutubu fields. The coiled tubing campaign at Agogo was completed with the successful installation of a gas lift system in the Agogo 7ST1 well. In September, Santos received a binding conditional offer from Kumul Petroleum Holdings Limited to acquire a five per cent project interest in PNG LNG for an asset value US$1.4 billion, including a proportionate share of project finance debt of approximately US$0.3 billion. For further information, refer to Santos' ASX release of 27 September 2022. The Papua LNG project pre-FEED activities continued to progress well through the quarter and remain on track to support a FEED-entry decision on the integrated project which is targeted by the end of 2022.

PREVIOUS HISTORY

August 2022: Clough, in consortium with Technip Energies, has been selected to perform the front-end engineering design (FEED) for TotalEnergies' Papua LNG project's upstream production facilities in Papua New Guinea. The upstream production facilities will cover the development of the Elk and Antelope onshore gas fields; this includes both the well pads and the central processing facility. Likewise, the upstream production facilities will also incorporate a carbon capture and sequestration (CCS) scheme to remove the fields' native CO_2 supply and re-inject it into existing reservoirs.

May 2021: A meeting took place on 3 May 2021 between Patrick Pouyanné, Chairman and CEO of Total, and a Delegation of Papua New Guinea (PNG) led by the Deputy Prime Minister Samuel Basil, with the objective to review together the next steps for the development of the Papua LNG project. Total and PNG Authorities will work together to foster significant in-country value and to implement the Papua LNG project in an exemplary manner. Additionally, Total and PNG intend to take the biodiversity and environmental stakes as well as the local communities' rights into the highest consideration.

February 2021: Papua LNG project partners Total (operator), ExxonMobil and Oil Search have signed an agreement with the Papua New Guinean Government that is expected to guarantee the fiscal stability of the proposed development. The agreement, the final step envisioned under the Papua LNG gas agreement, follows the amendments to acts passed by the PNG Parliament in November 2020. Oil Search managing director Keiran Wulff said the milestone highlighted the commitment from the PNG Government towards Papua LNG and is a signifi-cant step in derisking the project.

January 2021: Oil Search delivered record annual LNG production from its Papua New Guinean operations in 2020. The company's production rate for 2020 from the PNG LNG project was 8.8 million tonnes (mtpa), the highest ever annual rate for the project. However, total production for the quarter from the PNG LNG project was down from 8.9 mtpa in the third quarter to 8.7 mtpa. Looking ahead, production for 2021 is expected to be lower than 2020 due to scheduled service programs for the PNG LNG plant for trains one and two.

October 2020: Oil Search has reported that the ExxonMobil-operated PNG LNG project continues to perform ahead of expectations. The operation produced at record levels over the first nine months of 2020, reaching a rate of 8.8 mtpa. The output included 6.55 million barrels of oil equivalent (mmboe) from the PNG LNG project.