Narrabri Gas Project (SSD 6456)

Submission to IPC following public hearing

10 August 2020

Executive Summary

The Narrabri Gas Project is in the public interest, critical for energy security and reliability in New South Wales and would deliver significant economic benefits to NSW and the Narrabri region, including jobs, investment and regional development. At the same time, the Project is unlikely to result in any significant impacts on the local community or the environment. These are the findings of the Department of Planning, based on a rigorous, multi-year assessment process that relied on science and evidence, and independent expert opinion. Thank you for the opportunity to present to the Panel during the public hearing and to now provide a further submission on behalf of Santos.

Many of the key themes addressed in this submission have previously been raised through the extensive and comprehensive assessment process so far and were also covered in my presentation to the Panel.

Santos has relied upon the best available science, expert research and opinion in our application to develop the Narrabri Gas Project so that the community can be confident it will not harm people, water resources or the environment. As the Department of Planning found, it is "difficult to reconcile the significant community concerns about the Narrabri Gas Project with the technical advice from experts that the risk of any significant impacts occurring is generally low and can be controlled using standard engineering practice and imposing strict conditions on Santos".

While I outlined Santos' capability in my presentation to the Panel, one thing I would like to reiterate in this further submission is our strong track record of coexistence with farmers. We have worked in partnership for more than 65 years across the country and most recently as we have developed a coal seam gas industry in Queensland that is welcomed by farmers and rural and regional communities. Landholders have welcomed payments that help drought-proof their farms by providing a second source of income from hosting gas field infrastructure, allowing them to expand their business in other directions, purchase additional land and add value to their properties. Some have also gained a new, clean source of water supply, available only because of gas production.

Santos has more than 2000 land access agreements in place throughout the Bowen and Surat regions in Queensland and we have safely drilled and operated more than 2300 coal seam gas wells since 2006, without harm to water resources or the environment.

Many presenters and submitters were generally opposed to any new fossil fuel projects, including gas, pitting them against a renewable energy future.

However, the two must coexist to deliver the energy security and reliability that our society demands. The International Energy Agency says that natural gas will grow to supply a quarter of all global energy demand in 2040 in all its scenarios. On Australia's east coast, the Australian Energy Market Operator's Integrated System Plan has found that more gas supply needs to be developed each year from 2023-2024 to meet residential, commercial, industrial and power generation demand in southern Australia.

We have seen examples of large economies switching to gas from other fuels to reduce their emissions. In the United Kingdom coal-fired power generation has been phased out over the last two decades with gas now accounting for almost 40 per cent of total power generation. This has resulted in a reduction in CO_2 emissions of 38 per cent compared to 1990 levels. And, as our EIS outlines, the United States has also achieved large-scale emissions reductions from coal-to-gas switching, which the International Energy Agency says is critical to meet global climate goals. The Department of

Planning has also identified the role Narrabri gas could play in reducing emissions as aging coal-fired power stations close in eastern Australia over the coming decades.

Santos has set an aspiration of net zero emissions by 2050, we are driving change by deploying renewables, implementing energy efficiency projects, investing in technologies like carbon capture and storage and investigating the potential for hydrogen production. We are committed to a lower carbon future and taking practical measures to reduce our emissions, including at Narrabri where our appraisal gas is already being beneficially used for power generation at Wilga Park.

The economics of the Narrabri Gas Project stack up – Santos would not have already invested $1.5 billion in the Narrabri Gas Project if they didn't. Narrabri is an economically robust investment opportunity for Santos and one that will deliver numerous economic benefits for the community.

ACIL Allen has updated its assumptions on the Narrabri Gas Project to reflect current economic conditions.

In short, what the new analysis has found is that the impact for the local community and New South Wales more broadly has strengthened. It finds more jobs would be created. It confirms the Project would put downward pressure on gas prices and would create increased levels of regional development.

Simply, the Narrabri Gas Project will offer large volumes of gas to the domestic market on long-term contracts. This will support Australian industries like manufacturing to drive the economic recovery out of the COVID-19 pandemic.

The tightness in supply in the New South Wales gas market, where around 95 per cent of gas currently has to be imported from other states, has meant this has been difficult in recent years.

As our economy comes out of hibernation from the COVID-19 health crisis, every effort must be made to drive economic growth, investment and job creation, also mindful that such development must be ecologically sustainable.

Santos submits that the Narrabri Gas Project can be developed safely and sustainably, without harm to people, water resources or the environment. The Project will bring jobs and business opportunities to regional communities in New South Wales at a critical time.

Santos submits the following submission for consideration by the Panel.

K. T. Gallagher

Kevin Gallagher
Santos Managing Director and Chief Executive Officer

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1. Why the Project is needed

Some submitters questioned the strategic need for the Project in relation to gas market forecasts.

The NSW Government has recognised the need to secure future gas supplies through the development of an onshore gas industry in NSW. The *NSW Gas Plan* provides the framework for the regulation and management of the energy sector. The Narrabri Gas Project is identified as a Strategic Energy Project in the *NSW Gas Plan*.

The Project has the potential to supply up to 200 terajoules of natural gas per day, which is sufficient gas to meet up to half of NSW's natural gas demand. This is the natural gas that heats and powers more than one million family homes in NSW and fuels some 33,000 businesses. About 500 heavy industrial users consume approximately 75 per cent of the gas supplied to NSW and it is estimated that about 300,000 jobs rely on a safe and secure supply of natural gas. The gas would be made available for the NSW market to optimise the opportunities for the use of gas as a source of energy including via a high-pressure gas transmission pipeline.

The Australian Competition and Consumer Commission's inquiry into gas supply in Australia stated in its January 2020 interim report:

> *With declining production from established southern gas reserves, there is significant uncertainty about whether future supply from gas reserves and resources will be sufficient to meet overall demand on the east coast.*

A growing component of energy demand will need to be met by natural gas supply to complement renewables growth and battery storage in Australia as ageing coal-fired power plants close over coming decades.

<u>NSW Government's Net Zero Plan</u>

As stated on the NSW Government's website[1], *the Net Zero Plan Stage 1: 2020-2030, is the foundation for NSW's action on climate change and goal to reach net zero emissions by 2050. The plan aims to enhance the prosperity and quality of life of the people of NSW, while helping the state to deliver a 35 per cent cut in emissions by 2030 compared to 2005 levels. The plan will support a range of initiatives targeting electricity and energy efficiency, electric vehicles, hydrogen, primary industries, coal innovation, organic waste and carbon financing.*

Several proposed initiatives as outlined in the Memorandum of Understanding – NSW Energy Package executed by the NSW and Commonwealth Governments included:

- improving transmission interconnection and network access, including accelerating and delivering:
  - NSW's first Renewable Energy Zone; and
  - upgrades to the Queensland to NSW interconnector;
- setting a target to inject an additional 70 petajoules of gas per year into the NSW market, and agreeing to a gas market review if this target is not met by 2022;
- ensuring emissions reduction in the electricity sector stays on track;
- committing to invest $2 billion in reducing emissions in NSW; and
- supporting new generation investment in NSW.

In order to fulfil the Net Zero Plan objectives, the NSW and Commonwealth governments committed to jointly fund over $2 billion in energy and emissions reduction initiatives subject to the NSW Government's supply of an additional 70 petajoules per year (PJ/y) of natural gas into the east coast gas network.

1. https://www.environment.nsw.gov.au/topics/climate-change/net-zero-plan

Australian Energy Market Operator's (AEMO) Integrated System Plan

On 30 July 2020, AEMO released *its 2020 Integrated System Plan* (2020 ISP) for the National Electricity Market. The 2020 ISP sets out the optimal development path needed for Australia's energy system considering factors such as affordability, security, reliability and emissions outcome for consumers through the energy transition.

The 2020 ISP noted:

> *After gas fields cease production between mid-2023 and mid-2024, gas supply restrictions and curtailment of GPG (gas-powered generation) may be necessary, particularly during peak winter days.*
>
> *To avoid this, southern Australia will need to either develop new local sources (and pipeline infrastructure), progress liquefied natural gas (LNG) import terminals or address pipeline limitations from northern Australia. ISP modelling forecasts approximately 120 PJ to 285 PJ of additional gas will be needed each year between 2024-25 and 2036-37 to meet residential, commercial and industrial gas demand, gas for LNG export, and gas supply for GPG.*
>
> *GPG can provide the synchronous generation needed to balance variable renewable supply, and so is a potential complement to storage. The ultimate mix will depend upon the relative cost and availability of different storage technologies compared to future gas prices.*

Additional gas is required in the domestic gas market to meet residential, commercial and industrial gas demand.

AEMO's 2020 ISP suggests gas-fired power generation may have a more substantive role once coal generators are retired from 2030 onwards. The 2020 ISP identifies that 63 per cent of Australia's coal-fired generation will reach the end of its technical life by 2040. In NSW, this reduction in generation would include coal-fired generators at Liddell, Vales Point, Eraring and Baywater.

2. Downward pressure on NSW gas prices and more jobs

Some submitters queried whether the Project can put downward pressure on pricing and generate jobs in the Narrabri region. Comments were also made on projected future gas demand in NSW.

The 2016 economic analysis contained in the Narrabri Gas Project Environmental Impact Statement (NGP EIS) was recently updated by ACIL Allen to address issues raised during the IPC hearing.

The updated analysis reaffirms that the Project is vital for security of gas supply and job creation in NSW. The updated analysis also confirms that the Project will put downward pressure on NSW gas prices.

In summary the updated ACIL Allen analysis found that:

- Increasingly the southern states will require development of onshore resources as the existing developed and underdeveloped reserves are depleted. By the later 2020s and beyond, the Project will be among the lower cost resources.
- The Project can place downward pressure on gas prices in NSW, potentially by between 4 per cent and 12 per cent from 2025 onwards. Even if 40 TJ per day is provided to establish a local fertiliser plant, a 3 per cent to 9 per cent price reduction in Sydney is estimated.
- The Project will offer large volumes of gas on long term contracts. This has been difficult in recent times due to the tightness in supply and the lack of competition.
- Because of Santos' commitment that all the gas produced from the Project will be available for the domestic market, a new competitive source of supply close to Sydney is expected and this will lead to more competitive prices on long term gas contracts, particularly into the late 2020s and 2030s.
- This Project will create more jobs than previously estimated due to the economic restrictions placed on the previous model – the number of jobs created is 17 per cent higher (a total of 222 jobs) in the Moree-Narrabri region than in the NGP EIS and 78 per cent higher for NSW (a total of 912 jobs).
- The Project will significantly increase real economic output with the Gross Regional Product of the Moree-Narrabri region up by over $12.6 billion and NSW Gross State Product up by $14.7 billion compared to modelling without the Project. This is an increase of 14 per cent and 23 per cent respectively compared to the NGP EIS.

Appendix A contains further information on the updated economic analysis.

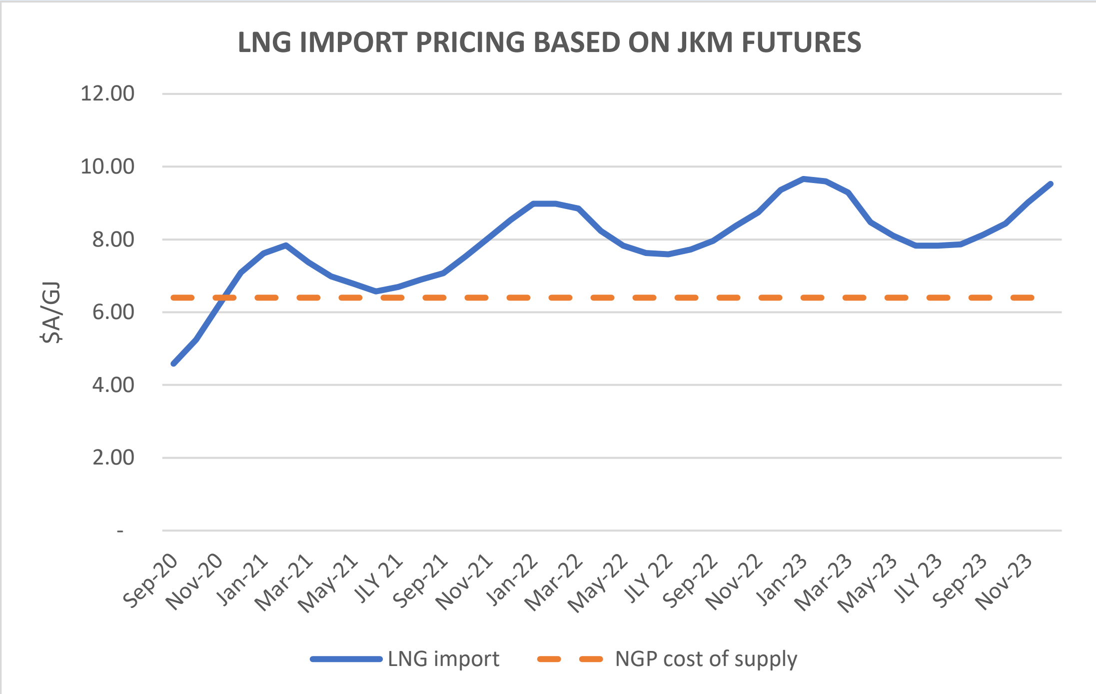
<u>LNG imports</u>

As some submitters identified, LNG imports may be an important addition to the east coast supply mix. However, these imports will not result in lower prices. LNG spot prices are at historically low levels brought about by the impact of COVID-19 on the world's economy. However, these LNG prices are forecast to return to normal levels according to the Japan Korea Marker (JKM) reference price which reflects the spot market value of LNG cargoes delivered into Japan and South Korea and was used in submissions as a relevant reference point for LNG import pricing. JKM also produces forward prices for the next 3 years which are pricing in a correction to these historic lows.

Charting these forward prices, converting them into Australian dollars per gigajoule and including shipping and re-gasification shows that LNG imports could be up to $3 higher than the cost of Narrabri gas in 2023-4 (see chart below).

Some submissions referred to the current low LNG prices that have been seen through the COVID-19 pandemic. These references apply only to spot prices. Spot prices vary significantly throughout the cycle, with LNG spot prices being as high US$14/GJ (~A$20/GJ) just a couple of years ago.

It should be noted that most LNG, including Santos' projects, is sold under long-term contract, to underpin the many tens of billions of dollars of investments in LNG supply. That's why, in the first half of this year, despite the oil price war between Saudi Arabia and Russia, and despite the demand side shock caused by a mild northern winter and the coronavirus pandemic, Santos has realised relatively strong LNG prices, averaging US$8.57/mmbtu, which is around A$12 per gigajoule, much higher than spot LNG prices and also higher than average realised domestic gas prices of around A$5.40 per gigajoule.



Note: Cost of shipping and gasification assumed to be AU$1.20 per GJ, AUD/USD 0.70, MMBTU/GJ 1.055

SOURCE: PLATTS JKM MARKER PRICE FOR LNG AS AT 22 JULY 2020

3. The role of natural gas in a low-carbon economy

Some submitters suggested that the Project should not be approved as it would contribute to an unacceptable increase in greenhouse gas emissions and that any forecast shortage in energy demand could be met by renewable sources of energy generation.

These submissions ignore the critical role of natural gas in the transition to a low-carbon economy, recognised by the International Energy Agency, or the relative contribution of the Project to Australia's overall greenhouse gas (GHG) emissions, which is not significant.

Natural gas can help meet growing global energy demand while reducing relative global GHG emissions. The International Energy Agency says that global emissions would have been 15 per cent higher in 2018 without coal-to-gas switching. If the natural gas produced by the Project was simply used to displace coal-fired power generation in the Australian energy market, it would be expected that this would also reduce CO_2 emissions.

Natural gas is the natural partner for renewable energy power generation as Australia and the world transitions towards a low-carbon economy. Gas is not considered a replacement for renewables but is required to complement renewables growth in solar and wind in Australia, which is intermittent. Similarly, battery storage is currently suitable for short term backup supply but cannot sustain the NSW electricity grid for extended durations.

Under the UNFCCC Paris Agreement, the Australian Government committed to a quantified economy-wide nationally determined contribution (NDC) to reduce national emissions by between 26 and 28 per cent on 2005 levels by 2030[1]. This Australian Government report went on to state the total net emissions were 12.9 per cent lower in 2018 than 2005 levels with a further reduction of between 13.1 per cent and 15.1 per cent required by 2030. Natural gas will perform an important role to achieve this commitment while ensuring reliable and secure energy supply, as recognised by the Australian Government.

Fuel switching to natural gas for electricity generation can deliver an improvement in emissions intensity of the electricity grid. As set out on page 20 of Appendix R of the NGP EIS, in the United States of America, fuel switching to natural gas enabled by the shale gas boom has resulted in an emissions reduction of 200 Mt CO_2-e per year. Similarly, in the United Kingdom, coal-fired power generation has been phased out over the last two decades, with gas now accounting for almost 40 per cent of total power generation. This has led to a reduction in CO_2 emissions of 38 per cent compared to 1990 levels. This gas-led reduction in emissions has allowed the United Kingdom to have one of the fastest declines in domestic emissions of the past 30 years[1].

Compared to coal and some existing sources of natural gas in the east coast gas market, Narrabri gas has a very low CO2 content, so would be displacing higher-emissions energy sources.

Santos supports limiting global temperature rise to less than 2°C in line with the Paris Agreement. The International Energy Agency's 2018 World Energy Outlook Report explored three pathways for energy sector development in 2040. Under an International Energy Agency scenario consistent with the 2°C target, global gas demand grows by 14 per cent by 2040 compared to 2016 and forms approximately a quarter of the global energy mix.

The International Energy Agency has subsequently released further reports including The Role of Gas in Today's Energy Transitions (July 2019) and Energy Technology Perspectives Report (July 2020), which found that:

> *While there is a wide variation across different sources of coal and gas, an estimated 98% of gas consumed today has a lower lifecycle emissions intensity than coal when used for power or heat. This analysis takes into account both CO_2 and methane emissions and*

> *shows that, on average, coal-to-gas switching reduces emissions by 50% when producing electricity and by 33% when providing heat.*

Similarly, AEMO's 2020 Integrated System Plan report forecasts a shortfall in natural gas supply and coal-fired power generation while also identifying a key role for gas in Australia's clean energy transition with the following statement.

> *After gas fields cease production between mid-2023 and mid-2024, gas supply restrictions and curtailment of GPG (gas-powered generation) may be necessary, particularly during peak winter days.*
>
> *To avoid this, southern Australia will need to either develop new local sources (and pipeline infrastructure), progress liquefied natural gas (LNG) import terminals or address pipeline limitations from northern Australia. ISP modelling forecasts approximately 120 PJ to 285 PJ of additional gas will be needed each year between 2024-25 and 2036-37 to meet residential, commercial and industrial gas demand, gas for LNG export, and gas supply for GPG.*

Gas power generation is expected to continue to provide a reliability and security role to complement renewable generation in the National Energy Market according to forecasts by the AEMO and State and Federal Government policy (AEMO 2020 ISP, AEMO 2020 Gas Statement of Opportunities).

The GHG emissions assessment for the Project was undertaken in accordance with the *National Greenhouse and Energy Reporting Act 2007* (NGER Act) and the National Greenhouse and Energy Reporting Regulations 2008. The NGER Act is a national system for reporting GHG emissions, energy production and consumption by corporations. The data gathered under the NGER Act assists with compiling Australia's national GHG inventory in order to meet Australia's reporting obligations under the United Nations Framework Convention on Climate Change.

Amendments to the NGER Act in late 2014 introduced a framework for a GHG Safeguard Mechanism which came into effect on 1 July 2016. The associated rules were tabled in Parliament in October 2015. The Safeguard Mechanism provides a framework for Australia's largest facilities to measure, report and manage their emissions.

The Safeguard Mechanism applies to facilities that emit more than a threshold of 100,000 tonnes of CO_2-e per year and requires facilities to pay a penalty if an "excess emissions situation" exists in relation to the facility. An excess emissions situation exists where the net emissions number for the facility is greater than its baseline emissions number. It is likely that in a typical operating year, the Project will trigger the 100,000 tonnes threshold and will therefore be subject to the Safeguard Mechanism.

Santos will report the Project's GHG, energy consumption and energy production in accordance with the NGER Act and manage any compliance obligations under the Safeguard Mechanism or any future carbon policy.

Annual direct GHG emissions for the Project in a typical operating year would be approximately 0.96 Mt CO_2-e with the on-site power generation facility, or 0.53 Mt CO_2-e with electricity sourced from the national grid. This is the equivalent of less than 0.2 per cent of current annual emissions in Australia and less than 0.002 per cent of current global emissions.

The relatively small increase (less than 0.2 per cent) in Australia's annual GHG emissions should be considered in terms of the net environmental benefit of the natural gas generated by the Project. In the transition to a lower-carbon economy, natural gas offers a unique opportunity for Australia by providing a lower-carbon alternative to existing fossil fuel energy sources.

The GHG emissions assessment (Appendix R of the NGP EIS) identified a range of measures to mitigate and manage the GHG emissions of the Project. These mitigation measures are primarily designed to reduce the Project's Scope 1 and Scope 2 emissions, and would be secured by the GHG conditions of consent which the IPC is required to consider in accordance with clause 14 of the *State Environmental Planning Policy (Mining, Petroleum Production and Extractive Industries) 2007*.

Santos has a long-term aspiration of achieving net-zero emissions by 2050 and has introduced a number of projects focused on carbon emissions reduction and renewable energy projects across our assets including:

- Moomba Carbon Capture and Storage Project, which proposes to capture the 1.7 million tonnes of carbon dioxide currently separated from natural gas at the Moomba gas processing plant each year and to reinject it into the same geological formations that have safely and permanently held oil and gas in place for tens of millions of years;
- Beam Pump conversion from oil to solar and battery power;
- Solar power introduction into Santos' Port Bonython processing plant in South Australia through a 2.12MW ground-mounted solar photovoltaic system;
- Heat recovery project at Moomba to reduce emissions;
- Santos' Darwin LNG battery project which will reduce carbon emissions from power generation by 20 per cent, as well as cut fuel gas consumption and operating costs; and
- Santos' Devil Creek in Western Australia is replacing existing power generation turbines with more fuel-efficient ones reducing emissions by more than 25 per cent and generating Australian Carbon Credit Units as a registered project with the Emissions Reduction Fund.

Santos will continue to identify and pursue opportunities to offset GHG emissions and beneficially re-use CO_2 where relevant in further support of achievement of emissions reduction targets.

In relation to downstream (Scope 3) emissions, as gas produced by the Project would be exclusively available to the domestic market, all Scope 3 emissions would be converted into either Scope 1 or Scope 2 emissions of the end users and as previously stated would be displacing higher emitting energy sources. This means that these emissions would be reported, mitigated and managed in accordance with Australian best practice standards, guidelines and policies. Importantly, it also means that all emissions generated by or associated with the Project will be considered by the Commonwealth Government in the context of Australia's global commitment to reduce its GHG emissions by 26-28 per cent emissions below 2005 levels by 2030.

1. The Australian Government Submission to the United Nations Framework Convention on Climate Change, Australian National Greenhouse Accounts, 2020
2. Hausfather, 2019, Analysis: Why the UK's CO_2 emissions have fallen 38 per cent since 1990.

4. Consistency of the Project with the principles of ecologically sustainable development

Some submitters referred to the principles of ecologically sustainable development (ESD) and the proper application of those principles, in particular the precautionary principle in relation to groundwater impacts and ecological impacts and the principles of inter-generational equity in relation to climate change and social and economic impacts.

Attached as **Appendix B** is an Opinion of Richard Lancaster SC addressing the ESD issues mentioned above as well as:

- the contention advanced in the NWA Submission about the Minister's Statement of Expectations for the Independent Planning Commission and procedural fairness to the NWA;
- the operation of clause 14 of the Mining SEPP; and
- the submissions made during the public hearing to the effect that the Project should not be approved because it has no "social licence".

5. Greenhouse gas and climate change

5.1 Reservoir CO2 production

Some submitters stated gas produced by the Project would have CO_2 content of at least 25-30 per cent not 10 per cent as assessed.

The NGP EIS assessed a conservative average of 10 per cent CO_2 content across the Project area over the 25-year assessment period.

Santos has not misrepresented the CO_2 content of the coal seams in the Project site. The data available from appraisal well gas continues to show that the composition of gas produced by the Project over 25 years would be no more than the average of 10 per cent CO_2assessed.

Between 2014 and 2019, over 250 gas samples were taken from approximately 32 operating appraisal wells. The average CO_2 content of the gas in these samples is less than 5 per cent. This sampling data, which is Commercial in Confidence due to commercial considerations linking gas content, composition to resource and asset value was provided to the EPA. While produced gas CO_2 content is below 5 per cent in these areas, the average in-situ CO_2 content is around 15 per cent and up to 24 per cent in some locations.

The difference between in-situ and produced CO_2 content regrettably led to some confusion in the submissions during the public hearing. Multi-isotherm science, the physics of relative gas sorption affinities, observation data gathered from field appraisal pilots and Santos' Queensland CSG operating experience, shows that CO_2 is produced at a much lower level than the proportion in-situ. Dr Andrew Grogan said that based on his analysis of data on the Geological Survey of New South Wales' DIGS website, the average CO_2 content of the gas would be at least 25-30 per cent. The table below shows the difference between the observed CO_2 content of produced gas and that of in-situ gas which is reported on DIGS.

Table 1: CO_2 Production Versus In Situ Analysis

Well	Pilot Location	Avg. CO_2 produced	Produced CO_2 estimated by Dr Grogan
Dewhurst 26	Dewhurst South	8.6%	20.8%
Bibblewindi 13	Bibblewindi East	4.3%	13.9% / 74.0% *
Bibblewindi 22	Bibblewindi West	2.1%	75% **

* Bibblewindi 11C is a corehole located alongside Bibblewindi 13. Dr Grogan's submission refers to 13.9% CO_2 from the Maules Creek Formation and 74% CO_2 from the Hoskissons Formation for Bibblewindi 11C. Santos has only produced from the Maules Creek Formation selectively and exclusively.

** Bibblewindi West 1C is a corehole located alongside Bibblewindi 22. DR Grogan's submission refers to 75% CO_2 from the Hoskissons Formation for Bibblewindi West 1C. Santos has only produced from the Maules Creek Formation.

The NGP EIS described and assessed approximately 95 per cent of production from the Early Permian Maules Creek Formation. The Late Permian Hoskisson's coal seam within the Black Jack Formation is a chronologically and stratigraphically separate coal seam with distinctive and varied gas composition. The 25-30 per cent CO_2 content suggested by Dr Grogan incorrectly assumes significant production from the Late Permian. Santos can and will selectively and exclusively develop independent coal seams based on best available science gathered during Project development. Should the Project be approved, further appraisal is required in order to refine those areas that are most economic. Santos remains confident that over the 25-year Project the average CO_2 content of the gas will not exceed the 10 per cent assessed.

Finally, in a typical operating year the Project will trigger the 100,000 tonnes threshold in the NGER Act as set out above. Therefore, the Project will be subject to the Safeguard Mechanism which is one of the key elements of the Commonwealth Government's plan to meet Australia's Paris commitments.

5.2 Fugitive emissions

Some submitters stated that the Narrabri Gas Project EIS had underestimated the predicted fugitive methane emissions

Santos is aware that several submissions made during the public hearing suggested that fugitive methane emissions would be much higher than those assessed in the NGP EIS.

Santos maintains that its assessment of fugitive emissions in the NGP EIS is accurate, based on best available science and data, and was prepared in accordance with all relevant policies and guidelines.

Under clause 14(2) of the *State Environment Planning Policy (Mining, Petroleum Production and Extractive Industries) 2007*, the IPC is required to consider:

> *…an assessment of the greenhouse gas emissions (including downstream emissions) of the development, and must do so having regard to any applicable State or national policies, programs or guidelines concerning greenhouse gas emissions.*

The NGP EIS Greenhouse Gas Assessment (Chapter 24 and Appendix R) was prepared in accordance with the following standards, guidelines and legislation:

- The Greenhouse Gas Protocol, A Corporate Accounting and Reporting Standard, Revised Edition, developed by the World Resource Institute and the World Business Council for Sustainable Development (GHG Protocol);
- The NGER Act and associated legislative instruments;
- American Petroleum Institute, Compendium of greenhouse gas emissions methodologies for the oil and gas industry, August 2009 (API Compendium);
- The Commonwealth Department of the Environment National Greenhouse Accounts (NGA) Factors, August 2016 (DoE 2016); and
- The Commonwealth Department of the Environment and Energy National Inventory Report 2014 (Revised), August 2016 (DoEE 2016).

The above documents are considered to represent current best practice in Australian GHG accounting. Conservative estimates were used so that emissions are overestimated rather than underestimated. For example:

- It was assumed that the Project would produce 200 TJ per day (TJ/day) of sales gas for the full 25-year assessment period. This volume is the maximum quantity of gas that would be produced for availability to the market at any time during the assessment period. In reality, at commencement of the Project, the quantity of gas will be significantly less than 200 TJ/day given that the Project will still be under construction. Using 200 TJ/day for the life of the Project is therefore a conservative estimate of the amount of methane and carbon dioxide emitted during gas processing.
- Similarly, power and heat requirements for the Project were assumed to be those that would be required to produce 200 TJ/day of sales gas. Basing the power and heat

requirements on the maximum daily production will also result in a conservative estimate of the quantity of methane combusted and/or the quantity of electricity sourced from the grid in order to power Project operations.

By contrast, fugitive emissions estimating techniques adopted in the public submissions, including by Lock the Gate, Dr Grogan and Tim Forcey, are not appropriate reference points for the Australian Coal Seam Gas industry.

CSIRO has undertaken a number of studies attempting to directly measure (quantify) fugitive emissions and their results show that the emissions reported under the Commonwealth NGER framework are acceptable. As there is national emissions reporting legislation in place for all industries, it would be inconsistent to use any other emissions forecasting methodology to estimate emissions for the Project.

Direct comparisons to international examples are inherently flawed due to differences in geology, regulation and development standards. CSIRO ('What does science tell us about fugitive methane emissions from unconventional gas?', May 2017) has explained that:

> *Gas production in the US has many differences compared to Australia due to history of gas development, size of the industry, dominance by shale gas over CSG production, differences in environmental regulatory controls and laws governing landowner rights over resources.*

It is important to recognise that, in the absence of the Project, there is, and will remain for the foreseeable future, a demand for energy generation to meet the basic needs of the Australian population. That demand will remain irrespective of whether the Project is approved and, if the Project is refused, the demand will simply need to be met by other energy sources including but not limited to LNG import into NSW via approved and planned facilities. These alternative sources of gas could be expected to have higher emissions impacts due to transportation requirements including liquefaction, transportation, regasification and other sources of emissions.

Santos accepts that any consent for the Project should be issued subject to conditions aimed at ensuring that the development is undertaken in an environmentally responsible manner, including conditions to ensure that GHG emissions are minimised to the greatest extent practicable. This is consistent with the approach undertaken to regulate the industry through the use of the Leak Detection and Reporting program, which is an existing licence condition regulated by the NSW EPA, with results reported annually.

6. Public liability insurance for landholders

Some submitters stated that public liability insurance was no longer available for landholders that host gas infrastructure.

Public liability insurance policies remain available, from various insurers, to farmers who host natural gas activities.

The suggestion made and repeated by some submitters during the public hearing that farmers who host natural gas activities are not covered by public liability insurance is incorrect.

Santos understands that a single insurer has decided to no longer insure farmers with oil and gas infrastructure on their property.

Consequently, on 29 June 2020 the Insurance Council of Australia, the Australian Petroleum Production & Exploration Association, National Farmers Federation, Queensland Farmers' Federation, AgForce, and Cotton Australia issued a joint statement, to reaffirm that public liability insurance cover remains available for farmers who host natural gas activities.

Farmers who host natural gas activities continue to benefit from the combined effect of insurance, legislative protections, and indemnities provided by petroleum operators.

Santos indemnifies landholders that host Santos infrastructure for losses arising out of petroleum operations. This indemnity is provided in Santos' land access conduct and compensation agreement that is entered into with landholders prior to the commencement of activities.

7. Salt waste

Some submitters stated that the NSW EPA Waste Classification Guidelines are not 'fit for purpose' and were not intended to apply to the classification of salt. Submitters also stated that because of the leachate that would be generated salt should not be disposed of at general solid waste facilities. Additionally, submitters stated that the volume of salt waste cannot be readily accommodated by existing waste facilities.

There are a substantial number of waste facilities available, including government and privately owned facilities, that are licensed to receive general solid waste in the order of hundreds of thousands of tonnes per annum. Submitters incorrectly suggested that existing waste facilities do not have the capacity to take the salt waste, and that it is not feasible to dispose of the salt waste at existing waste facilities. The average volume of salt produced annually by the Project would be a very small proportion of the overall capacity of any one such facility.

Submitters incorrectly stated that the NSW EPAs 2014 *NSW Waste Classification Guidelines* do not apply to salt. The *NSW Waste Classification Guidelines* apply to the classification of all waste in NSW, including salt waste. Testing was undertaken in accordance with the *NSW* W*aste Classification Guidelines* based on the chemical composition of the produced water. The results are summarised in the NGP EIS and show the salt waste would classify as general solid waste and was significantly below relevant thresholds.

General solid wastes leach both organic and inorganic substances. Some submitters incorrectly suggested the general solid waste facilities could not or should not receive salt waste because of the leachate that would be generated. The design of landfills that would be suitable to receive the salt waste, in accordance with EPA guidelines, include barriers and leachate collection and extraction systems to perform in the long-term. Designs incorporate both natural and manufactured barriers, drainage layers and plant selection to prevent rainfall infiltration once a landfill is capped and rehabilitated. These types of controls require minimal maintenance in the long-term.

In accordance with the waste hierarchy, Santos will continue to explore all beneficial use opportunities. Beneficial re-use opportunities include but are not limited to:

- Natural Soda Bicarbonate production following the recent completion of the pre-feasibility study and subsequent MOU to progress the Concept Design and Engineering Study, and the Front End Engineering Design through 2021.
- Assisting to neutralise acid mine leachate in mine rehabilitation, following extensive laboratory trials and discussions with the EPA, Santos and a trial partner are planning field trials through a trail heap leach pad within an existing mine.

In accordance with the recommended conditions of consent, prior to Phase 2 of the Project Santos will provide a Produced Salt Beneficial Reuse and Disposal Study to Department of Planning, Industry and Environment (DPIE) for approval.

8. Incident notification protocol

Some submitters stated that in the event of a pollution incident notification response protocols were inadequate or did not exist. Others said that relevant state agencies and the community should be notified.

If there is an incident there is a statutory obligation under the NSW *Protection of the Environment Operations Act 1997* for Santos to notify the EPA immediately, and the recommended conditions of consent also require Santos to notify DPIE and other relevant agencies immediately.

If an incident were to occur, it would also be an offence for Santos not to notify the EPA and members of the community identified in a Pollution Incident Response Management Plan. A Pollution Incident Response Management Plan has been developed for the current exploration and appraisal activities in the Project area to manage potential environmental emergencies or incidents in accordance with the requirements of the NSW *Protection of the Environment Operations Act 1997*.

The Pollution Incident Response Management Plan details responsibilities for site staff managing environmental incidents, regulatory and community notification requirements and provides details of potential pollutants and safety equipment. If the Project is approved the Plan would be reviewed and updated to apply also to the Project.

Santos has a long history of working across multiple jurisdictions with vast experience of having response plans in place. Stringent internal governance and testing of processes along with regular response exercises ensure the performance and effectiveness of these plans to protect people and the environment.

9. Water

9.1 Water access licences

Some submitters stated that Santos must hold Water Access Licences, and that there may be insufficient market depth for Santos to acquire the Water Access Licences required by the recommended conditions of consent.

All water extraction for each water source will be under a Water Access Licence issued by DPIE in accordance with the *Water Management Act 2000*, as is the case for other water users in NSW including irrigators and industrial users. Santos has purchased entitlement for the Gunnedah Oxley Basin (GOB) groundwater source and holds in excess of 3.5 GL, an annual limit sufficient for full development of the Project.

Regarding the other groundwater sources trades in Water Access Licences over the past three years are summarised in the table below. These trades demonstrate sufficient market depth. The relatively small entitlements can be obtained through the open market in accordance with recommended conditions of consent without disadvantaging other licence holders.

Groundwater source	NGP EIS Base Case (37.5 GL) Peak flux change at source base		Average volume traded annually since 2017 ML/y
	ML/y	Time (years after start of FDP, to nearest model time step)	
Gunnedah-Oxley Basin	3,553	3	Required entitlement has been purchased
GAB Southern Recharge	57.3	190 - 200	1,900
GAB Surat	0.16	950 – 1,000	340
Lower Namoi Alluvium	4.19	250 – 300	6,600
Upper Namoi Alluvium	1.00	250 – 300	350

9.2 Groundwater

9.2.1 New studies said to prove faults connect target coal seams with shallow aquifers

Some submitters stated that scientific studies published recently provide new evidence of connectivity between target coal seams and shallow aquifers that was not considered by DPIE in its assessment of the Project. They state that the Project's groundwater model may significantly underestimate predicted groundwater impact on shallow aquifers. A recent scientific paper by Iverach et al (2020) was cited by a number of submissions as providing evidence of connectivity between Project target coal seams and shallow aquifers, such as the Pilliga Sandstone and the Lower Namoi Alluvium.

Contrary to statements made in a number of such submissions, Santos has previously acknowledged the detection of methane in shallow aquifers, and in particular in the shallow Namoi Alluvium (NGP EIS Response to Submissions 6-74).

In general, methane is observed at low and varying levels in all formations above the target coal seams, though most groundwater samples do not record methane above limits of reporting. Alluvium groundwater with elevated methane occur along the Namoi River, north-east of the Project. It is this dissolved methane which was the subject of analysis by the Iverach et al. (2020) paper.

Multiple lines of evidence indicate most known faulting within the Project area is of small scale and does not extend into the overlying formations. Potential impacts to groundwater flow due to faulting is highly unlikely at the local and regional scale. As referred to in the NGP EIS Response to Submissions (5-16, 6-90), Santos has undertaken an in-depth review of the existing data that supports its findings on fault characterisation. The inferred fault data presented by Iverach et al. (2020) is not new. Most faulting within the Project area is considered to be compressional and associated with closure of the Bowen-Gunnedah-Sydney basinal systems during the middle Triassic.

The connectivity between the Great Artesian Basin (GAB) and the overlying alluvial aquifers is well documented. While the evidence presented in the Iverach et al. (2020) paper is consistent with very small volumes of gas migrating over geological time scales into the Namoi Alluvium, other reasonable and competing hypotheses for the presence of methane are equally probable.

There are a number of issues with the analysis and conclusions presented in the Iverach et al. (2020) paper in regard to its relevance to the Project groundwater impact assessment.

1. The area of study is located outside the Project area. The paper considers evidence of connectivity in shallow aquifers located to the north of the Project, not within the Project footprint. Drawdown impacts in the target coal seams due to the Project are not expected to extend more than 5 km beyond the tenement. The area of relatively high fault density studied will not be affected by Project activities. The Project area avoids high density fault areas and also areas of locally intrusive volcanic rock.
2. The paper’s characterisation of faults relies on a qualitative assessment of lineaments and does not adequately describe or characterise faults with any rigour (e.g. fault length, depth, orientation, throw, stress regime, age, formation mechanism, etc.). Based on the information reported in the paper (e.g. a low-resolution and highly stylised geological cross section; uninterpreted seismic data and coarse-scale maps of ‘inferred’ fault locations), it is not clear whether an adequate and appropriate peer review could have been undertaken regarding geological structures. Cited references do not provide the detail nor supporting investigations to validate the inferences made in the paper regarding fault characterisation and their potential effect on hydrogeological connectivity.
3. The geochemistry data do not confirm that the low concentrations of dissolved methane observed in the Namoi Alluvium is sourced from the coal seams of the GOB. There are other reasonable and competing hypotheses not presented by the paper that may explain how the observed methane has migrated from other sources:
    a. No data are presented describing dissolved gas isotope signatures of the Pilliga Sandstone or any other aquifers or aquitards of the GAB which are alternative potential sources of methane in the region (e.g. Herzeg & Torgeson, 1991; DMR, 2002).
    b. There is an absence of supporting groundwater chemistry data to support the conclusion that faults are responsible for upward migration of dissolved methane from the GOB. For example, given there is a natural upward hydraulic gradient (i.e. deeper units are under greater pressure than shallower units), changes in

water quality such as increased chloride would be expected because the deeper aquifer units and coal seams of the GOB are far more saline than shallow aquifers.

c. The paper estimates that the concentration of methane in underlying formations that would be required to explain the changes in methane isotopic signatures in the alluvial sediments is 4,062ppm. Iverach, et al. report (in Table 1b) methane concentrations in the formations underlying the GAB are 800,000ppm and explain that this supports a hypothesis of upward gas migration. However, this appears erroneous, as the data presented appears to have been transcribed incorrectly and actual concentrations are up to 800ppm (i.e. 800,000 µg/L). Hence the reported evidence shows a decrease in methane concentration at depth, not the increase in concentration as described.
d. Irrigators on the Namoi Alluvium extract groundwater from the underlying Pilliga Sandstone to irrigate crops. Excess water infiltrates and adds to the alluvium groundwater, hence introducing water with a “GAB signature” into the local alluvial groundwater. This complicates the process of quantitatively assessing the natural flux between the GAB and the alluvium in this region based on water chemistry alone.
e. Gas isotopes presented for the alluvial groundwaters outline a distinct signature, separate from the Gunnedah Basin groundwaters (Figure 7a in Iverach, et al., 2020), with the former exhibiting a relatively heavier carbon signature in methane for a given carbon dioxide value, reflecting a methyl fermentation origin and not the methane oxidation origin proposed in the paper.

Based on the evidence presented, conclusions that can be drawn from the paper are:

1. There is likely connectivity between the Namoi Alluvium groundwaters and the underlying groundwaters of the Great Artesian Basin.
2. Biogenic methane in deeper layers of the alluvium likely undergoes oxidation as it rises to the surface.
3. Where there is elevated sulphate and/or oxygen, methanogenesis is inhibited.
4. Gas may be migrating over geological time scales from deep coal seams, but there is no evidence to support significant connectivity through faults.

9.2.2 Assessment of impacts to water bores of the Gunnedah Oxley Basin

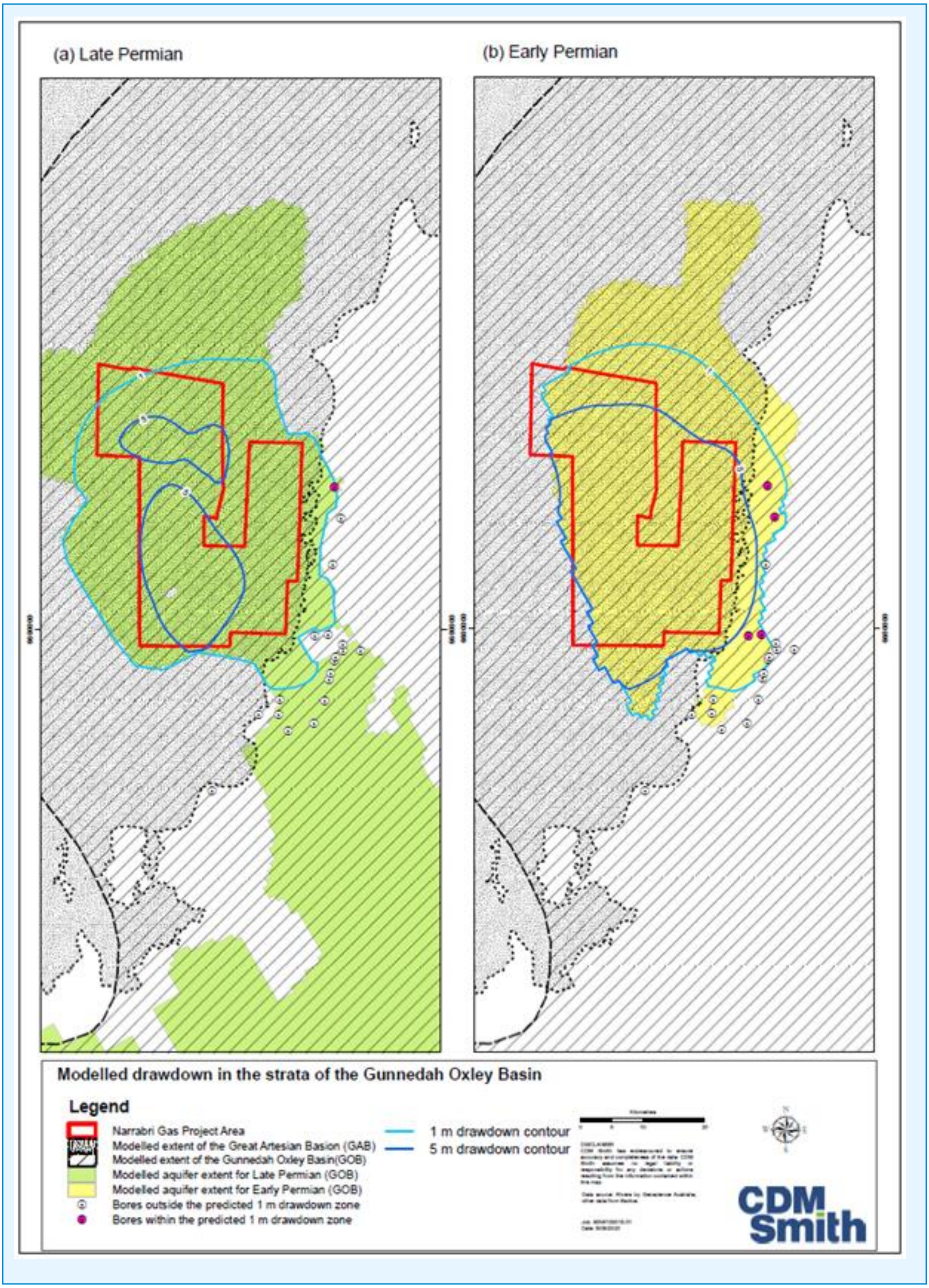
Some submitters stated that there is potential for significant impact to landholder bores that source water from aquifers of the GOB based on the NGP EIS, but this was not subsequently assessed by DPIE.

This scale of potential impact to water bores can be adequately managed through monitoring and adaptive management as prescribed in the recommended conditions of consent which allow for early detection of drawdown effects in the Gunnedah Basin.

The NGP EIS (GIA, Section 4.8.1) identifies that approximately nineteen bores within 30km of the Project area are identified as accessing deeper groundwater sources of the GOB. These bores are located east of the Project area and within the outcrop area of the GOB, which is situated between the southern recharge beds of the Pilliga Sandstone and the Namoi Alluvium.

The potential risk of impact to these bores greater than the minimal impact criteria of two metres drawdown is considered negligible. Even if it is assumed that these bores extract water from the same coal seams targeted by the Project (i.e. Early Permian formations of the GOB), groundwater modelling shows only four of these bores are located close enough to be potentially affected (see figure below).

The monitoring network would identify any issues many years (likely decades) in advance of any effect and if required make good provisions would be straightforward and effective. This is consistent with the Department's Assessment Report, and advice to the Department from the Water Expert Panel, that the risk to stock and domestic bores is low.


(a) Late Permian
(b) Early Permian
Modelled drawdown in the strata of the Gunnedah Oxley Basin
Legend
Narrabri Gas Project Area
Modelled extent of the Great Artesian Basion (GAB)
Modelled extent of the Gunnedah Oxley Basin(GOB)
Modelled aquifer extent for Late Permian (GOB)
Modelled aquifer extent for Early Permian (GOB)
Bores outside the predicted 1 m drawdown zone
Bores within the predicted 1 m drawdown zone
1 m drawdown contour
5 m drawdown contour
CDM Smith

9.2.3 Assertions that aquitards in the groundwater model were not adequately characterised or conceptualised

Some submitters had concerns about the way in which the Project groundwater model characterised aquitards. Firstly, it was suggested that the vertical permeability values were not conservative, and that higher permeability values could reasonably be expected. Secondly, some submissions further suggested that the aquitards may not be laterally continuous as assumed by the model, and so this would also underestimate vertical permeability.

The adequacy of the vertical permeability values derived for aquitard layers has been addressed in the NGP EIS Response to Submissions on pages 6-73 to 6-74 and 6-77 to 6-78.

Within the NGP EIS, Table 5-2 in the groundwater Impact Assessment (NGP EIS Appendix F) describes a limited number of very localised measurements of hydraulic conductivity in Great Artesian Basin and Gunnedah Basin strata. These, however, are local-scale point measurements that do not directly scale to model cells, which represent a minimum area of one square kilometre in the NGP EIS groundwater model.

CSIRO (p 40 – 41,Turnadge et al. 2018) derived a single equivalent vertical permeability value for each of four aquitard units, their interburden units, and the combined aquitard-interburden unit utilising information from exploration well geophysical wireline logs, and porosity and permeability measurements of core samples from key aquitard formations. The permeability values used in the NGP EIS groundwater model can be compared to the median values derived by CSIRO. The values are similar for the Watermark and Porcupine formations, less for the permeability of the Purlawaugh Formation by one order of magnitude, and greater for the Napperby Formation by a factor of approximately 50. This results in a model that is conservative in terms of potential drawdown as compared to the CSIRO model. That is, the NGP groundwater model is more likely to over-estimate drawdown in shallower aquifers.

On the suggestion that aquitards may not be laterally continuous, an independent review of all permeability data by CSIRO found no evidence that regional aquitards were discontinuous. In a study on multiscale aquitard hydraulic conductivity characterisation applicable to the Gunnedah Basin, New South Wales (p 39 – 42, Turnadge et al. 2018) CSIRO concluded:

- For the Purlawaugh and Napperby aquitards that "Based on the distribution of permeability data displayed in Figure 28, with median values of the "Combined" results consistently estimated at approximately 3.2×10-3 mD (equivalent to a hydraulic conductivity of 2.4×10-6 m/d), there is no evidence of discontinuity in the sealing capacity of the aquitard formations. Furthermore, an overall maximum hydraulic conductivity of 10-5 m/d (based on a maximum permeability of approximately 10-2 mD) is not indicative of a loss of sealing capacity."
- For the combined lower (Permian age) aquitard sequence, "Based on the distribution of permeability data displayed in Figure 29, with median values of the "Combined" results consistently estimated at 3.2×10-2 to 10-2 mD (or hydraulic conductivity around 2.4×10-5 to 7.6×10-6 m/d), there is no evidence of discontinuity in the sealing capacity of the aquitard formations. Although the overall maximum hydraulic conductivity of 0.7 mD is about two orders of magnitude larger than the median (Table 8), this is not indicative of a loss of sealing capacity."

Furthermore, the regional geological model was not based solely on interpolated borehole data (as suggested by submissions), but also many thousands of kilometres of 2D seismic data that gives confidence in the extent and continuity of strata across the model domain. This is especially of relevance when it comes to the continuity of aquitards deposited in a marine or large lacustrine depositional environment which are typically laterally continuous.

The WEP states (p 28) that "In the NGP EIS, the Project has used standard depositional models for the Gunnedah and Surat sedimentary systems and in the hydrogeological models, which is a realistic approach given the level of data availability" and further "The NGP EIS approach of bounding the problem based on extrapolation of existing data is seen as plausible. This suggests that even with higher assumed permeability, drawdown can be predicted with a reasonable level of confidence".

References:

Turnadge C, Esteban L, Emelyanova I, Nguyen D, Pervukhina M, Han T and Mallants D (2018) Multiscale aquitard hydraulic conductivity characterisation and inclusion in groundwater flow models: Application to the Gunnedah Basin, New South Wales, prepared by the Commonwealth Scientific and Industrial Research Organisation (CSIRO), Canberra.

NSW Department of Planning, Industry and Environment (2020) Groundwater Resource Description - NSW Great Artesian Basin, PUB20/74, February 2020.

9.2.4 The timing of updates to the groundwater model

Some submitters stated that the recommended conditions of consent require a Class 2 or Class 3 model when it was "practical and feasible", and that this is not acceptable given the lack of certainty that is inferred from results of a Class 1 groundwater model.

Santos is committed to periodically reviewing the Project groundwater model using the best available data, and as described in the NGP EIS and in accordance with the recommended conditions of consent.

A detailed response to the requirement of updating the NGP EIS groundwater model to confidence level Class 2 and 3 has been given on pages 2-7 and 2-8 of the NGP EIS Supplementary Response to Submissions.

One of the requirements for achieving a groundwater model with a Class 2 or Class 3 confidence level is a "transient calibration". This means the model must be calibrated to aquifer monitoring data that shows a clear drawdown response in aquifers over time due to Project activities.

A meaningful transient calibration for impact to a shallow aquifer due to Project activities will not be possible if there is no measurable effect to that aquifer. It is important to acknowledge that the change in groundwater pressure in shallow aquifers due to Project activities is expected to be negligible and may not therefore be practically measurable.

Furthermore, the maximum drawdown influence is not expected to peak for many decades. In Queensland, the Office of Groundwater Impact Assessment have not yet undertaken meaningful transient calibration of its groundwater model for impact to aquifers due to CSG activities in the Surat and Bowen Basins, an area with up to 8,000 active CSG wells and more than 20 years of CSG production. This is principally because the observed changes in groundwater pressure are limited to the coal seams and have not propagated into aquifers to any meaningful extent that could be used to calibrate groundwater impact model predictions.

Model calibration to satisfy requirements of a Class 2 or Class 3 confidence level may, at best, take many decades to achieve. Furthermore, it may not be possible to achieve unless drawdown effects in an aquifer are practically measurable. In this context, a condition of consent that requires a groundwater model with a Class 2 or Class 3 confidence level only when "practical and feasible" is appropriate.

9.2.5 Assertions that temperature dependency of groundwater pressure has not been modelled

Some submitters expressed concerns that the groundwater model was not designed to account for temperature dependency of modelled groundwater pressures. This was inferred to demonstrate that the findings of the groundwater model were not reliable.

> Temperature effects on predictive estimates of groundwater head distribution in the Pilliga Sandstone aquifer was raised by the WEP as a potential source of error. Temperature data for the Pilliga Sandstone does not suggest this discrepancy will materially affect the findings of the groundwater impact assessment because the effect of temperature dependent groundwater density on pressure heads will be negligible.
>
> The Pilliga Sandstone range in depth between 50 m and 400 m, and temperature between 24°C to 29°C where potential water take may be induced due to the Project.
>
> Hydraulic conductivity changes due to changes in dynamic viscosity with temperature are very small for a temperature range between 24°C to 29°C (approximately 10 per cent change in hydraulic conductivity) when compared to the range of hydraulic conductivity due to variability in the lithofacies across the Pilliga Sandstone (i.e. variability across several orders of magnitude).

9.2.6 Assertions that groundwater model uncertainty analysis demonstrates the potential groundwater impacts are unacceptable

Some submitters stated that the NGP EIS did not present adequate uncertainty analysis and that the findings of the uncertainty analysis undertaken by the CSIRO demonstrated that the risk of groundwater impact was unacceptable.

> Contrary to suggestions made by several submissions, Santos undertook uncertainty analysis of groundwater model predictions for the Project. This is addressed in NGP EIS Response to Submissions p. 5-17 to 5-18. The Santos and GISERA analyses informed the WEP's finding (as reported in the DPIE's assessment report, p 58) that the risk of unintended groundwater movement due to the Project is small.
>
> Uncertainty analysis has been undertaken by GISERA (Sreekanth et al. 2017a), addressed in NGP EIS Response to Submissions p 6-76. GISERA's groundwater modelling considered probabilistic results based on 500 realisations of various model parameters, generating a range of water production volumes between 4.4 gigalitres and 107 gigalitres. This is compared to the NGP EIS maximum extraction of 37.5 gigalitres over the life of the Project.
>
> GISERA reports the 5th, 50th (median) and 95th percentile maximum flux between the Pilliga Sandstone and deeper with a high level of confidence using a parsimoniously parameterised model. Using this model, the 95th percentile predicted induced water-take from the Pilliga Sandstone was 2,299 ML/year. Estimated flux impacts peak after approximately 30 years of CSG production and decline to below 220 ML/year after 80 years.
>
> It is important to acknowledge that GISERA's upper estimates of flux from the Pilliga Sandstone, besides being based on a very wide range of modelled connectivity parameters, makes some deliberately conservative assumptions about the Project's extraction from the coal seams. GISERA's model assumes that half of the CSG wells abstract water from the shallower Hoskissons coal seam. However, around 95 per cent of total Project production will come from the deeper

Maules Creek coal seam. The Hoskissons coal seams are stratigraphically much closer to the Pilliga Sandstone than the deeper coal seams of the Maules Creek Formation.

The GISERA model estimates an extraction rate of up to 107 GL of water extracted from the coal seams over the life of the Project. However, the proposed conditions of consent limit extraction to 37.5 gigalitres over the life of the project. There is no uncertainty in the estimate of water production. The maximum extraction volume which approval is sought is 37.5 gigalitres over 25 years without contingency on the performance of the field.

In this context, the CSIROs upper estimate of 2,299 megalitres of year peak induced flux from the Pilliga Sandstone does not inform an assessment of the possible impacts of the Project, particularly since 95% of production will come from the deeper Maules Creek Formation and Santos will not be permitted to extract more than 37.5 gigalitres over the life of the project.

In any case, and to put a highly conservative estimate into perspective, an induced flux of 2,299 ML/year from the Pilliga Sandstone is similar in scale to the average volume traded annually since 2017 in the GAB southern recharge groundwater source (i.e. 1,900 ML/year).The approach for improving model confidence is addressed in the NGP EIS, Appendix G3 and the NGP EIS Response to Submissions p 5-13 to 5-14, 5-36, p 5-41 to 5-42 and p 5-58. The recommended conditions of consent require Santos to prepare a Groundwater Management Plan including a groundwater management and monitoring system. The key principal of the groundwater management and monitoring system is that monitoring activities are designed to improve model certainty over time, as well as inform whether the Project is contributing to changes in water quantity or quality within water assets, particularly the high valued groundwater sources in the Great Artesian Basin and Namoi alluvial aquifers.

9.2.7 Assertions that the Project groundwater model cannot adequately predict impact to Namoi Alluvium

Some submitters asserted that the groundwater model could not accurately predict impact to the Namoi Alluvium since the Project groundwater model does not accurately model connectivity between the GAB and the Namoi Alluvium as compared to other groundwater models of the same system.

The WEP report highlights differences between the Project groundwater model and a groundwater model designed to inform water management policy for the Namoi Alluvium, reviewed by Noel Merrick in 2001 (the NA Model).

The discrepancy between the NA Model and the Project model relates to the modelled net flux (i.e. discharge) from the GAB to the Lower Namoi Alluvium *in absence of any potential CSG effects*. These fluxes are very small compared to the annual water usage from the Namoi water source (as acknowledged by the WEP report, p 50).

A detailed discussion on the spatial variability of the Namoi Alluvium and natural leakage (i.e. the flux) between the alluvium and the underlying Great Artesian Basin has been provided in the NGP EIS Response to Submissions, p 6-79 to 6-88.

The discrepancy between the Namoi Alluvium model and Project model does not affect the findings of the Project groundwater impact assessment. The discrepancy of modelled fluxes is insignificant when considered at the spatial scale of the different models and the scale of abstraction from the water resource itself.

The Project groundwater model is well-suited to assess the potential effect of coal seam water extraction on overlying aquifers of the Great Artesian Basin and the Namoi Alluvium. This is supported by numerous independent reviews, including by the CSIRO in 2015 and NSW DPI in 2017. The overarching conclusion from the WEP report is that the Project groundwater model is "fit for purpose and the predicted impacts minor".

9.2.8 Risk to aquifers from loss of containment

Some submitters stated that the likely and scale of spills of CSG water throughout the life of the Project would pose an unacceptable risk to groundwater receptors, such as aquifers of the GAB.

Submissions referred to case-study data from the US to infer particularly high spill rates for CSG operators in Australia. Such submissions failed to recognise the successful operation of CSG in Queensland, which is a better analogue of the regulatory and operational regime under which the Project will operate than case-studies from the US. For example, in Queensland, no regulatory enforcement action has been required in a period where up to 8,000 CSG wells have been operating and all spills greater than $5m^3$ in volume must be reported to the regulator.

The Project will operate under all applicable Australian Standards and an EPA approved Pollution Incident Response Management Plan will be in place that includes provision for management of spills and notification of the EPA and landholders. Potential impacts from spills and responses have been considered in the NGP EIS (Chapters 11, 12, 14 and 25), the NGP EIS Response to Submissions (sections 5.4, 5.7, 6.6, 6.7, 6.12 and 6.14) and Question 19 from the WEP.

Given the proposed risk controls that will be in place, the likelihood of a significant spill going undetected and unmanaged is very small. The likelihood of small spills causing significant impact on groundwater receptors is extremely small since the spill would be limited to a small area (less than a few hectares) and CSG water is generally free from potentially harmful contaminants.

9.2.9 Assertions that the Project is located in a major recharge zone for the GAB

Some submitters stated that the Project is located in a major recharge area of the GAB, contrary to claims made in the NGP EIS, and that this poses an unacceptable risk to aquifers of the GAB.

This issue was addressed in the NGP EIS Response to Submissions (Section 6.11.1, pages 6-68 to 6-70). The Project is not located in a significant recharge zone of the GAB in NSW.

Water Expert Panel's Key Observation 1 "The volume of water that provides the recharge in the Project area to be developed by Santos is relatively small compared to that of the dominant area of recharge in NSW to the south along the eastern flank of the Coonamble Embayment of the GAB." (Report of the Water Expert Panel, Review of the Narrabri Gas Project, page 23, February 2020).

DPIE's most up-to-date assessment of recharge rates (published Feb 2020) confirms that the Project location does not overlie a major recharge zone for the GAB. (Full reference: Southern and Eastern Recharge Groundwater Sources: Literature Review and Recommended Recharge

Rates, final report prepared for NSW Department of Planning, Industry and Environment, D10200A04 (KCB, 2020)).

The simple fact is that Project activities pose very little risk to regional-scale groundwater recharge processes whether or not the Project is located in an area of significant recharge zone of the GAB. The likelihood that a significant surface spill that could affect a regional aquifer is negligible and, regardless of the magnitude, aquifer drawdown effects do not influence aquifer recharge rates.

10. Aboriginal cultural heritage

10.1 Compliance with consultation guidelines

Some submitters stated that consultation was not undertaken in accordance with the government policy, *Aboriginal cultural heritage consultation requirements for proponents* (NSW Government 2010).

A number of submissions on the NGP EIS stated that the consultation with Aboriginal communities had not been undertaken in accordance with the relevant guidelines. The same claim was repeated in submissions to the IPC. This issue was addressed in the NGP EIS Response to Submissions.

Consultation was undertaken in accordance with the Secretary's environmental assessment requirements and *Aboriginal cultural heritage consultation requirements for proponents* (NSW Government 2010). The process captured responses from a very large geographical catchment, as is made clear in the Aboriginal Cultural Heritage Assessment Report in Appendix N1 of the NGP EIS. There were over 550 Registered Aboriginal Parties from a wide geographic area, all of whom were provided with hard copies of the draft Aboriginal Cultural Heritage Assessment Report and draft Cultural Heritage Management Plan, and all of whom were given the opportunity to make a submission.

The DPIE Assessment Report and the independent expert engaged by the department found that consultation had been undertaken in accordance with the relevant guidelines. The Assessment Report states that:

> *Santos has complied with the Aboriginal cultural heritage consultation requirements and should be able to avoid most of heritage items in the project area.*

Engagement with the Aboriginal community was not confined to the specific requirements of the Secretary's environmental assessment requirements. Discussions were held at approximately 10 towns / localities across the Gomeroi Nation, often at the invitation of the local Aboriginal community including Toomelah in the north, Coonabarabran and Gunnedah in the south, and Walgett in the west. At some of these locations discussions were held on several occasions. Field tours or field inspections were also offered, including providing transport to Narrabri.

10.2 Cultural values of Aboriginal people

Some submitters stated that the Aboriginal Cultural Heritage Assessment Report was not thorough or adequate when considering cultural values of Aboriginal people. Submitters asserted the assessment did not meet the relevant assessment requirements and government policies in that regard.

During the consultation process all Registered Aboriginal Parties were expressly provided the opportunity to provide information regarding Aboriginal cultural values. Santos committed to undertake an Additional Research Program to address this issue the details of which are described in the Aboriginal Cultural Heritage Assessment Report in Appendix N1 of the NGP EIS, and in the draft Cultural Heritage Management Plan.

In addition to the Secretary's environmental assessment requirements, additional measures were taken to provide an opportunity for elders to participate in information sessions and field tours, including examination of elements of the Project and to provide input. Elders from the region participated in field tours and information sessions.

The assessment concluded that by application of the avoidance principle there would be no impact on cultural heritage sites that have been assessed of high significance. The assessment also concluded that in relation to cultural values the impact of the Project would either be non-existent for some, minimal for others, and operate in the short to medium term to the extent that there is an impact for others.

The avoidance principle and precautionary principle will be implemented through the Cultural Heritage Management Plan (CHMP), Appendix J of the NGP EIS Response to Submissions. In accordance with the recommended conditions of consent the CHMP must be finalised in consultation with the Aboriginal community. Under the terms of the CHMP all currently known sites and the most sensitive site types will be completely avoided by the Project.

Aboriginal people are responsible for the management of their heritage. The CHMP establishes an Aboriginal Cultural Heritage Working Group that will select the appropriate Cultural Heritage Officers to walk country, and select the Cultural Heritage Coordinator. The CHMP outlines the process for pre-clearance surveys and for the management and protection of new finds discovered during carrying out of Project activities.

11. Ecology

11.1 Offset land availability

Some submitters stated that there is insufficient offset land available to meet the requirements of the Project. Submissions also stated that Santos would not be able to secure adequate offsets due to the uniqueness of the Pilliga

The Project requires approximately 6,400 hectares of 'like for like' native vegetation to offset impacts to biodiversity. The recommended conditions of consent require 70 per cent of the total offset liability to be retired before the commencement of Phase 2 (construction). With the proposed mitigations and the processes set out on the Field Development Protocol for the siting of infrastructure, it is unlikely offsets in addition to 70 per cent will be required.

An analysis of freehold land in the region was undertaken and reported in the NGP EIS Response to Submissions. The analysis showed there is over 280,000 hectares of suitable 'like for like' native vegetation available in the region. This analysis was supported by a real estate search in December 2017 which focussed on large rural properties. While over 6,700 hectares of suitable 'like for like' native vegetation was available for purchase at that time establishing offset sites is not confined to land for sale at any particular time.

In addition to land available for purchase, Santos currently has more than 5,000 hectares of suitable native vegetation available for offsetting identified by private landholders through an expression of interest undertaken in accordance with the *NSW Biodiversity Offset Policy for Major Projects.*

11.2 Suitability of offsets

Some submitters raised issues regarding the suitability of biodiversity offsets to account for the impacts of the Project suggesting the proposed offsets do not conform to relevant guidelines.

The Biodiversity Offset Strategy included in the NGP EIS is consistent with the *Framework for Biodiversity Assessment* and *NSW Biodiversity Offsets Policy for Major Projects*. Offsets requirements for the Project were calculated in accordance with the *Framework for Biodiversity Assessment* for all residual impacts on biodiversity values (ecosystem and species credits).

The offsets package includes a range of measures, including land-based offsets, supplementary measures, complementary measures (such as Koala research) and the use of the Biodiversity Conservation Fund to acquit remaining offset liability. These measures are mandated by policy.

11.3 Indirect impacts

Some submitters claimed that indirect impacts as a result of the Project had not been adequately assessed in the NGP EIS. Written submissions stated that indirect impacts had been grossly underestimated and that a number of species are disproportionally affected by indirect impacts.

Indirect impacts have been quantified and assessed in detail in the NGP EIS. This includes detailed consideration of site impacts such as fragmentation, noise, traffic, feral animals, fencing, downstream impacts such as sedimentation, hydrological change and accidental spills, and facilitated impacts such as hunting. The magnitude and extent of indirect impacts were quantified and assessed for each infrastructure type. While the effect of fencing was assessed, the contribution to the indirect impact of the Project was minimal because the gathering system will not be fenced.

For the purposes of offsetting only and despite not being required by policy, Santos has committed to offset the 180 hectare indirect impact of the Project as if that area was fully cleared. Indirect impacts are approximately 0.18 per cent of the 95,000 hectare Project area.

11.4 Fragmentation

Some submitters stated that fragmentation as a result of the Project has not been assessed, others said that fragmentation has not been adequately assessed.

The part of the Pilliga in which the Project is located has been variously disturbed by a long history of forestry activities including the establishment of more than 1,000 km of roads and trails in the Project area.

The fragmentation impacts of the Project have been assessed in detail in the NGP EIS including evaluation of the impacts based on the scale of fragmentation, width of open spaces, dispersal potential and home ranges of threatened species.

Linear clearing would be an average of 10 metres wide during construction (up to 12 metres wide in some cases) and rehabilitated to approximately 5 metres wide during operation. Infrastructure will be co-located with existing access roads, tracks or other existing linear features wherever possible. Wells will be at least 750 metres apart.

Assessment of the significance of impacts was undertaken for each threatened species. The assessment found that due to the progressive development of the Project, the narrow width of linear infrastructure and progressive rehabilitation proposed to be undertaken immediately following construction, the fragmentation associated with the Project is not considered likely to inhibit dispersal of any species, including Pilliga Mouse.

11.5 Feral animals

Some submitters stated that the Project will result in an increased impact from feral animals in the Pilliga.

Impacts of feral animals on threatened species have been assessed in detail in the NGP EIS. This includes consideration of feral animal populations currently present, existing disturbances including over 1,000 km of roads and trails, and impacts such as predation, competition and habitat modification.

It is widely accepted feral animals are widespread and abundant in the Pilliga and that current levels of feral animals are likely to be the single largest threat to biodiversity in the Pilliga. Predators such as foxes, dogs and cats are known to use roads as movement corridors through the landscape. In the Pilliga and due to its largely open nature feral animals are not confined to roads.

Feral animal control activities are planned to occur within the Project area. Strategies for management of feral animals will be implemented during all phases of the Project including construction, operation and rehabilitation. The relevant measures of the Biodiversity Management Plan will ensure that feral fauna present within operational areas are managed effectively to avoid additional impacts from feral animals.

11.6 Approach to impact assessment / uncertain forward footprint

Some submitters raised concerns that the approach to the impact assessment and the uncertain forward footprint make it difficult to assess the impacts of the Project. In particular concerns were expressed that the scale of direct impacts are not certain and are likely to be underestimates as they do not include access tracks.

The assessment of biodiversity impacts of the Project is robust and was undertaken in accordance with the *Framework for Biodiversity Assessment*.

Unlike more traditional resource projects, the precise location of surface infrastructure is unknown and is guided by progressive exploration, appraisal and development. Santos engaged a specialist consultant to develop upper disturbance limits based on a rule set and range of development scenarios. The upper disturbance limits include all Project infrastructure. The direct and indirect impacts of the project equate to the removal of about 1.5 per cent of the native vegetation in the project area, with impacts to threatened fauna species accounting for less than 2 per cent of the total habitat available in the study area, and less than 1.6 per cent of the total abundance of any threatened flora species.

The avoidance of significant ecological values has been prioritised in every stage of the assessment, including the upper disturbance limits. The NGP EIS has assumed worst case and that all limits for every ecological feature including vegetation, habitat and individuals will be cleared (despite this not occurring). This is the impact which has been assessed. The project will not have a significant impact on threatened species and ecological communities as the magnitude of direct, indirect and cumulative impacts are considered unlikely to effect the long-term survival of the species or ecological communities in the project area. This is due to the small proportion of habitat being removed relative to that retained in the study area; the removal of habitat not being at a scale likely to result in the isolation or fragmentation of populations; that the project is unlikely to result in invasive species or diseases becoming established; and that progressive rehabilitation of disturbed areas will be implemented as part of the project.

11.7 Survey effort

Some submitters raised concerns regarding the level of survey effort undertaken for the NGP EIS. In particular, submissions were made that the survey effort is insufficient for some key threatened species including Koala, Pilliga Mouse, Eastern Pygmy-possum and the Five-clawed Worm-skink and that important areas of habitat were not identified.

The biodiversity assessment undertaken for the NGP EIS draws upon more than 13,000 hours of field survey effort, which is the most comprehensive assessment undertaken for a development Project in NSW.

The surveys undertaken as part of the NGP EIS have been undertaken in accordance with the methodology, habitat stratification and replication as outlined in State and Commonwealth Survey Guidelines, with specific consideration of the scale and distribution of threatened species habitat across the landscape and the amount of habitat likely to be directly impacted by the Project.

Ten threatened flora species were identified through comprehensive threatened flora survey, only two of which were known to occur in the area prior to surveys. Fauna survey, including targeted survey for a range of key species including Koala, Pilliga Mouse and the Spotted-tailed Quoll, identified a large diversity of threatened fauna species including 18 threatened birds, 11 threatened mammals and one threatened reptile. The most detailed fine-scale vegetation map in the Pilliga was also prepared for the NGP EIS. These surveys informed the impact assessment, and with the proposed mitigations risks can be managed and the impacts are not significant.

11.8 Koala

Some submitters raised concerns regarding the status of Koala, with a few submitters also stating that the Koala is 'functionally extinct' in the Pilliga.

The Koala and potential habitat were assessed and described in detail in the NGP EIS. The NGP EIS included surveys for the Koala and identified the likely presence of the Koala, based on potential habitat. Surveys for the Koala and habitat mapping were conducted as required by the *Framework for Biodiversity Assessment*, State and Commonwealth legislation and impacts were assessed in accordance with relevant legislation.

Historically, the Pilliga forests have had a koala population of variable density. Population trends appear to have fluctuated from common in the late 1800's to sparse after 1930, then increasing from the early 1980s until the late 1990s (van Kempen 1997, Kavanagh and Barrott 2001). However, it was not until recent decades that repeatable research methods provided a strong measure of koala abundance.

The north-east Pilliga (including the Project area) has been surveyed for Koalas at various times, including during periods when the Koala populations in the Pilliga were considered to have been at historical peaks. Very few koalas have ever been found in the north-east Pilliga. The vast majority of Koala records are in the central and western Pilliga, areas supported by more productive soils, fewer fires, and greater access to permanent water along major drainage lines.

The combination of low soil fertility, associated nutrient-poor vegetation, periodic fires and fewer major watercourses with permanent water are considered likely to be the key reasons why Koala populations have always been low in the Project area, and there has been a low correlation between mapped habitat and the presence of Koala.

A regional Koala survey, including significant areas of the Pilliga outside of the Project area was undertaken by Koala experts and these results informed the assessment. The aims of this study were to identify and locate the key habitat and/or climate refuge areas where koalas were able to persist and from which population recovery may occur. This information is regarded as of great significance to conservation and forest managers.

All surveys of the Koala in recent times (for the Pilliga) have highlighted that population has been declining and this is acknowledged in the NGP EIS. The declining population and low correlation between mapped Koala habitat and the presence of Koalas are the primary reasons why the regional Koala survey was commissioned.

The NGP EIS concluded that the impacts of the Project on the current Koala population will not lead to a long-term extinction of a viable local population.

Offsets have been proposed for the Koala in the Biodiversity Offset Strategy. In addition to the offsetting requirements, the NGP EIS has provided a commitment to undertake a Koala research project to identify where the remnant populations of Koala are in the Pilliga in order to effectively target resources for the maintenance and improvement in the health of the population.

11.9 The avoid, mitigate and offset hierarchy

Some submitters raised concerns that the avoid, mitigate and offset hierarchy had not been followed. Others stated that offsets were too heavily relied on and that avoidance and mitigation were not sufficient.

Offsets requirements for the Project were calculated in accordance with the *Framework for Biodiversity Assessment* for all residual impacts on biodiversity values (ecosystem and species credits), following avoid, minimise and mitigate principles as outlined in the NGP EIS.

Measures to avoid and minimise impacts are embedded and at the heart of the NGP EIS and proposed conditions of consent and include design alterations and stage by stage infrastructure siting plans to maximise use of areas within or adjacent to existing disturbance or with lower sensitivity. This strategy will continue to reduce the overall extent of clearing required and will minimise additional fragmentation and additional edge effects within the landscape. The strategy includes:

- Implementation of the Field Development Protocol and the Ecological Scouting Framework;
- Placement of seismic infrastructure in previously cleared areas where practicable to avoid vegetation clearing;
- Placement of central water and gas processing facilities at the Leewood site outside of the Pilliga Forest to minimise vegetation clearing;
- Co-location of linear infrastructure with existing roads, access tracks and disturbance corridors wherever possible;
- Minimising widths of linear infrastructure corridors to 10 metres wide on average (up to a maximum of 12 metres); and
- Utilisation of the 'plough-in' technique where possible to reduce linear corridor widths and minimise disruption to topsoil.

A suite of mitigation measures including the development and implementation of a Biodiversity Management Plan, Rehabilitation Strategy, clearing procedure and Pest Plant and Animal Management Plan as well as specific measures such as implementation of speed limits and minimisation of night driving, lighting controls, dust suppression, sediment and erosion control have been proposed in the NGP EIS and will be implemented subject to Project approval.

The Biodiversity Offset Strategy is the mechanism to provide the offsets and has been presented in the NGP EIS as a commitment to deliver the Biodiversity Offset Package. The Offset Strategy is consistent with the principles of the Framework for Biodiversity Assessment and NSW Biodiversity Offset Policy for Major Projects.

11.10 Groundwater dependent ecosystems and stygofauna

Some submitters stated that impacts on stygofauna has not been assessed, and that impacts to stygofauna may be significant.

Information previously provided by Dr Serov was considered by Santos, and a response provided in the NGP EIS Response to Submissions. The stygofauna confirmed by Dr Serov were collected in the Namoi Alluvium. The diverse stygofauna of the Namoi Alluvium were acknowledged by Santos in the NGP EIS Response to Submissions. Santos also assessed that stygofauna may be present in the Bohena Creek alluvium, noting that if taxa are present in Bohena Creek they are also highly likely to be present in the Namoi Alluvium.

There is an insignificant risk of impact to alluvial groundwater dependent ecosystems due to the large degree of physical separation, both vertically in the sub-surface and horizontally at the surface, and therefore lack of connectivity between the target coal seams and groundwater dependent ecosystems.

The effect of the Project on the Namoi alluvium is predicted to be 0.003 per cent of the water currently allocated under licences to landholders. Project impacts on groundwater dependent ecosystems and their respective communities including stygofauna will be negligible.

The effect of the Project on the GAB is predicted to be 0.23 per cent of the water currently allocated under licences to landholders. Project impacts on groundwater dependent ecosystems and their respective communities including stygofauna, if present, will be negligible.

The Project assessment also examined groundwater dependent ecosystems to the east of the Project, including three sites that the Government identified as high priority Groundwater Dependent Ecosystems (GDEs). These three sites Eather Spring, Hardy Spring and Mayfield Spring are currently farm dams. Given proximity to the interface between the Pilliga Sandstone and the Purlawaugh Formation these farms dams are fed by water table springs (contact springs). As operational farm dams all three sites are highly modified through excavation and damming of drainage lines upstream, land use and through stock access. None of the sites retain ecological values and processes associated with groundwater and are therefore no longer GDEs.

12. Assessment of light from the Project

Some submitters stated that the light assessment was not accurate, measurements taken of flares with shields were not representative and cumulative impacts with other light sources were not assessed.

A Gas Flare Light Assessment was undertaken and provided as Appendix K to the NGP EIS Response to Submissions. It found that operation of the flares would result in limited light impacts well below the threshold in the *Dark Sky Planning Guideline* (Department of Planning and Environment 2016). The assessment considered the cumulative effect of the Project with existing background light sources including the towns of Narrabri, Baradine, Coonabarabran, Boggabri and mines in the region. Measurements were taken from existing flares, none of which are shielded.

Light spills from other Project sources would be limited through compliance with Australian Standard *AS/NZS 4282 – 1997 Control of the obtrusive effects of outdoor lighting*. This may include the use of narrow beam floodlights with spill light limited either through appropriate luminaire selection or through the use of “barn door” or similar shading devices fitted to the light fittings. To minimise skyglow, the standards require no light output above the horizontal plane.

Santos will continue to liaise with the Siding Spring Observatory during construction and operation of the Project. In accordance with the request from the Observatory, Santos has agreed that routine maintenance requiring use of the safety flares will be scheduled during periods when the moon is more than 50 per cent illuminated.

13. Social impact

Some submitters claimed that Santos did not have adequate mitigation strategies in place to manage the social impacts of the Narrabri Gas Project.

Consistent with Santos' core value of "Building a better future", Santos will continue to work in partnership with local communities and invest in social infrastructure and economic development opportunities that address impacts created by the Project and/or to leave a positive legacy for future generations. These benefits will be applied across the local community in the areas of health, education, environment, economic development, heritage, sport, arts and culture.

If approved, the Project will contribute up to $120 million to a Community Benefit Fund (CBF). Some submissions raised concerns with the current CBF framework which is currently under review by the NSW State Government. Santos will continue to engage with Narrabri Council and the NSW Government to finalise the CBF framework including governance, long-term community benefit and the process for identifying projects.

In accordance with the NSW State Significant Project's approval process, Santos has committed to preparing a detailed Social Impact Management Plan (SIMP), for approval by the Secretary of the DPIE, following determination and prior to commencement of construction. Following determination, the SIMP will be prepared in consultation with relevant stakeholders in the region and will address Project approval conditions. The SIMP will include detailed action plans including impacts, corresponding mitigation/management strategies, monitoring measures, reporting and reviewing processes.

14. Hazard & Risk: Bushfires & Flaring

14.1 Climate change & Bushfire Risk Analysis

Some submitters made statements relating to increased frequency and intensity of bushfires due to climate change related extreme weather conditions:

As previously stated through the NGP EIS Response to Submissions and associated technical reports, bushfire risks have been addressed based on the extremely conservative weather conditions with the analysis conducted based on a Forest Fire Danger Index (FFDI) rating of 120. This conservative approach is suitable to ensure any increase in bushfire frequency or intensity as a result of climate change is addressed as part of the assessment.

Background:

The Secretary's environmental assessment requirements for the Project included a requirement to assess likely risks to off-site safety including potential bushfire risk and risks associated with the transport, storage, handling and use of dangerous goods. A hazard and risk assessment was undertaken Appendix S of the NGP EIS. A desktop bushfire risk assessment was also carried out, complemented by publicly available information. The assessment considered the risk of a bushfire being started by a Project related activity during construction or operation.

The risk of a bushfire being caused by the Project was assessed with consideration of both Project activities and surrounding environmental factors. The assessment found that with the implementation of appropriate mitigation and management measures, the:

- risk of uncontrolled loss of gas leading to a fire or explosion was low to very low;
- the likelihood of bushfire ignition from a Project related activity was remote; and
- the overall risk was assessed to be medium given the potential consequences associated with bushfire.

The assessment identified mitigation and management measures to control the identified risks, including a Fire Management Plan prepared in conjunction with landholders, the Forestry Corporation of NSW and the NSW Rural Fire Service. The Plan would formalise and build on measures already in place as informed by Santos' participation in the Resource Industry Fire Management Group.

The likelihood of a Project activity causing a bushfire is remote given the range of measures proposed in addition to measures already in place, again as informed by Santos' participation in the Resource Industry Fire Management Group. These measures would be documented in a Fire Management Plan in accordance with recommended condition of consent B75, which would be developed in consultation with the landholders, NSW Rural Fire Service and Forestry Corporation of NSW.

Bushfire risk would also be reduced through features incorporated into the engineering design of the Project, including remotely operated well infrastructure with fail safe valves allowing for isolation of the source of gas, gas blowdown systems to reduce the inventory of gas contained within bushfire affected area, buried gathering lines and appropriately rated electrical instrumentation and equipment. This is consistent with the approach used in Queensland.

14.2 Bushfire Impacts on Project Infrastructure

Some submitters made a number of statements relating to bushfire impacts on Project infrastructure:

Some submitters asserted that the radiant heat flux of 150 kW/m^2 and bushfire temperatures in the order 1,600°C at the reaction zone would impact on infrastructure based on a CSIRO report Bushfire in Australia: Understanding hell on earth, 2015.

The radiant heat flux of 150kW/m^2 is not representative of Pilliga forest types and represents radiant heat flux within the flame front of an extreme crown fire in wet sclerophyll forest with extreme fuel loads on steep slopes.

The dominant vegetation type in the Pilliga is Western Slopes Dry Sclerophyll Forest, which the NSW Rural Fire Service (NSW RFS) Comprehensive Vegetation Fuel Loads publication (NSW RFS, 2019) identifies as having a surface and elevated fuel load of 14 tonnes per hectare (those being the fuels used to calculate radiant heat flux using the Australian Standard AS3959:2018 Construction of buildings in bushfire prone areas). The Radiant Heat Flux at 20 metres (representative of the setback distance between gas well infrastructure and vegetation) is 18.3 kW/m^2. This radiant heat flux level is just 12.2 per cent of the 150 kW/m^2 cited during the public hearings.

In accordance with Australian standards steel pipework at the well head must withstand 650°C for 30 minutes and maintain integrity (NGP EIS Hazard and Risk assessment Appendix S). Well head infrastructure will be surrounded by an asset protection zone, and will not be exposed to reaction zone temperatures. The 2015 CSIRO report estimates the temperature at the tips of flames is around 600°C. Elevated temperatures on the steel pipe at the well head will therefore be less than 650°C, and duration will be significantly less than 30 minutes.

14.3 Risk to NSW Rural Fire Service & Forestry Corporation of NSW in the event of bushfire

Some submitters stated concerns relating to NSW Rural Fire Service staff and volunteers being exposed to heightened risk due to Project infrastructure

Throughout the project assessment process Santos has had extensive engagement with both NSW RFS and Forestry Corporation of NSW to address questions raised, as well as extensive engagement at an operational level with local NSW RFS and Forestry Corporation of NSW staff through Santos' participation in the Resource Industry Fire Management Group.

As previously stated through the NGP EIS and NGP EIS Response to Submissions, there is no obligation or expectation that NSW Rural Fire Service or Forestry Corporation of NSW firefighters will be required to protect Project infrastructure in the event of a fire.

Fire detection and reduced response times in the Pilliga has been demonstrated to be significantly enhanced by the provision of fire detection cameras by Santos, and the presence of Santos staff and contractors.

Santos supports fire response agencies by providing access to water resources and equipment, earth moving equipment, a fire detection camera, telecommunications infrastructure and access to refuge zones should they be required. Santos' presence in the Pilliga assists the fire response agencies and Santos will continue to support these agencies through the proposed development and ongoing operations.

Infrastructure Design

As part of the Fire Management Plan and facility design, the radiant heat exposure will be determined using the current proposed asset protection zone, and a prioritised risk management response applied that will include construction design measures and operational protocols.

As discussed in Chapter 6 of the NGP EIS (Project description) and Response to Submissions, the Project would include a number of systems that would enable Santos to quickly cease operations in the event of a bushfire. Gas wells would be equipped with telemetry systems that provide real time information on well operations. The telemetry systems can be used to remotely 'shut in' wells. Further, gas wells would have automated shutdown systems that would be triggered in the event of non-routine operating conditions.

These systems, in combination with automatic gas blowdown systems, would serve to isolate the well from the well head skid and gathering system minimising the amount of gas stored in pipelines and gas processing infrastructure.

The infrastructure downstream of the well head, including the gas gathering lines and vents or drains, would be depressurised to the gas compression units or flare system and, as such, the operating pressure in the gas gathering network would rapidly approach atmospheric pressure.

These automated systems would minimise risk to the public and the Project workforce in the event of a bushfire.

The proposed Fire Management Plan will address all operational aspects associated with fire response agencies and Santos employee bushfire risks including evacuation procedures. This Plan is prepared in conjunction with bushfire response agencies.

14.4 Firefighting equipment impacting Project infrastructure

Some submitters stated that there was potential for NSW RFS / Forestry Corporation of NSW equipment including bulldozers, damaging Project infrastructure including underground pipelines.

As stated in the NGP EIS Response to Submissions, all gas pipelines for the Project will be designed and constructed to relevant Australian Standards. The applicable standard for steel gas transmission pipelines is AS2885.6:2018 (the Standard), and for HDPE gathering line it is the AGPA Code of Practice for Upstream Polyethylene Gathering Networks – CSG Industry Version 4.0 Supplementary (2017). Both provide risk-based methodologies for safety management.

Minimum depths of cover are specified for gathering lines. In rural locations, such as the Pilliga, the minimum Depth of Cover (DOC) for the HDPE gathering pipelines is 750 mm.

Typically, when constructing control lines through forest, bulldozers operate with their blade just above the ground level, or at the soil surface. The bulldozers would also be operating at the direction of incident controllers. Santos provide information on the nature and location of Project infrastructure to the NSW RFS and Forestry Corporation of NSW to include on its maps during fire incidents.

Given the DOC at which pipelines are installed, they will not be damaged by bulldozers or other equipment constructing emergency control lines during bushfire control operations.

14.5 Flare Design and Operation

Some submitters stated the use of flares in the forest would ignite bushfires, including that wind-blown debris could be ignited.

The design parameters used for flares exceed the NSW RFS requirements to address radiant heat flux.

Safety flares at Leewood and Bibblewindi would be up to 50m tall and be surrounded by a vegetation free zone of up to 130 metres radius. The maximum radiant heat flux at the nearest vegetation would be 6.31 kW/m^2 at both ground level and at the tree canopy under a catastrophic bushfire danger level (FFDI 120) which is considered extremely conservative. As such, the radiant heat flux would be significantly less than 10kW/m^2 specified by NSW RFS.

Santos design standards were described in the NGP EIS Response to Submissions are summarised below:

Radiation contours must be produced for flares. The maximum allowable radiation levels for flare design are listed in the table below and are based on API STD 521.

Location	Maximum Allowable Total Thermal Radiation Level (kW/m^2)(1)
Maximum at grade, typically directly below flame centre	9.46
Sterile area boundary(2)	6.31
Vegetation (grass, trees)	6.31
Flare Knock-Out Drum, Liquid Seal Drum(3)	4.73
Nearest Process Plant Boundary	3.15
Facilities Boundary Without Public Access Within 70 m from Boundary	3.15
Facilities Boundary With Limited Public Access(4) up to Boundary	2.37
Areas where workers or members of the public are continuously exposed(5)	1.58

Notes

(1). Total thermal radiation level **includes** solar radiation equal to 90% of the value tabulated for the typical average spring and autumn day for locations detailed in 1515-010-DSG-0002. This solar radiation level is typically the yearly average radiation level between the hours of 10 AM to 2 PM. For locations not covered by 1515-010-DSG-0002, local solar radiation data for a typical spring and autumn day must be used, or in the absence of local data, a value of 0.8 kW/m^2 must be used.

The maximum allowed radiation level where any vegetation occurs is 6.31 kW/m^2, (sum of solar radiation 0.8 kW/m^2 and the maximum allowable radiation from flaring combustion 5.51 kW/m^2). Modelling of radiation contours are calculated for worst case scenarios (i.e. maximum flaring rate, maximum ambient, low humidity, high wind), that would coincide with an FFDI > 120. While vegetation growth is continually suppressed in the sterile area (by appropriate ground cover such as blue metal and weed management) the maximum allowed radiation level anywhere at ground level is 9.46 kW/m^2 and as such would be below the radiation limit specified by the NSW RFS.

The radiant heat from flares at the nearest vegetation has been conservatively reported by Santos at <=6.31 kw/m^2 and in all likelihood is actually significantly lower. It is therefore well under the 10 kw/m^2 required by the NSW RFS.

In recent years Santos has modified existing development consents to connect all operating pilot wells to the gas gathering network, enabling beneficial re-use of gas through the Wilga Park Power Station. The Narrabri Gas Project intends to continue with this philosophy and tie in proposed pilot wells where feasible. This is consistent with the Santos wide philosophy to minimising flare, fuel and vent activities across our operations.

<u>Flares & Windblown Debris</u>

Several submitters made reference to the whirly-whirly wind scenario and the potential to start fires by means of lofted vegetative material being ignited in gas flares and falling to ground starting a bushfire.

This is not supported by evidence of vegetation fires starting in such a manner, with no identifiable record of fires having started from such causes. Gas flare operation will be in full compliance with the requirements of the Rural Fires Act 1997.

The potential for windblown debris to pass through safety flares or pilot flares and result in the ignition of a bushfire is considered negligible. This is because of the distance to potential ignitable sources of wind carried debris, and because the heavier debris types required to ignite and spread fire are most likely to be blown along or near the ground, not at the height of the flares. Small air-borne particles (if they were to pass through the flares) are expected to incinerate within the flare or burn to extinction prior to reaching the edge of the sterile zone.

14.6 Ignition probability understated due to climate change

Several submitters made reference to the likelihood of a loss of containment creating a fire being estimated at once in 70 years and it being a likelihood that there will be a 150 per cent increase in the probability of bushfire conditions due to climate change, raising the probability to 1 in 28 years of the Project starting a bushfire.

Some submitters contended that the 1 in 70 years for fire starts as outlined in the Departments Assessment Report, would be more like 1 in 28 years considering climate change. The 1 in 70 years is the estimated frequency for methane gas ignitions only and is therefore highly conservative and not impacted by climate change. It does not mean that this would lead to a fire-related event as it does not consider the probability of these ignitions escalating and leaving the site boundaries and further escalating to cause a bushfire, which is an even more remote risk.

The two sources of fire start are independent of each other, as climate change will not affect the frequency of fire starts from any potential methane gas releases from Santos infrastructure.

When considering the risk associated with ignitions escalating beyond the Project site boundaries, this assessment would need to consider a range of mitigation measures in place which further reduce the likelihood of Project activities causing a bushfire. For these fire events to escalate to a bushfire, the fire must be large enough and the conditions conducive for it to extend offsite to a vegetated area and not be extinguished in a suitable time. There are no known incidents within the CSG sector causing large scale bushfires.

Various considerations and mitigation measures to prevent escalation beyond the site boundary include:

- low operating pressure of the wellhead equipment and gathering system and very low frequency of wells being shut in resulting in higher pressures;
- methane dispersion in open air very readily to concentrations well below its flammability limits;
- valid hazardous area equipment ratings;
- a permit to work system, which is mandatory across the industry, includes a hot work permit and associated controls, including ensuring firefighting equipment is available and a trained fire watcher onsite;
- the wellsite infrastructure is located within the vegetation controlled 100m x 100m lease area, such that the distance to the fence line from any release point is larger than ~37.5m;
- facility infrastructure being located within a much larger cleared footprint with designated asset protection zones; and
- orientation of release and if ignited the extent of 12.6 kW/m^2 heat flux beyond the fenced area.

When considering the cumulative likelihood of a gas release, failure of control measures resulting in ignition and then that ignition scenario impacting beyond the site boundary, the cumulative likelihood would be considered in the order of 1 in 2,600 years which is considered improbable.

Santos is committed to making bushfire risk as low as reasonably practicable through the implementation of appropriate engineering design principles, the Fire Management Plan and working with the NSW Rural Fire Service and Forestry Corporation of NSW in relation to bushfire management activities in the Pilliga.

Appendix A Economic analysis

Appendix B Opinion of Richard Lancaster SC – Ecologically Sustainable Development

Santos Limited

Santos NSW (Eastern) Pty Ltd

Narrabri Gas Project (SSD 6456)

Opinion – Issues raised in IPC public hearing

7 August 2020

1. My instructing solicitors, Corrs Chambers Westgarth, act for Santos NSW (Eastern) Pty Ltd (**Santos**), which is the proponent of the Narrabri Gas Project (**Project**).

2. On 3 March 2020, the Minister for Planning and Public Spaces, The Hon Rob Stokes MP (**Minister**) made a request to the Independent Planning Commission (**IPC**) to conduct a public hearing into the carrying out of the Project prior to determining the State Significant Development (**SSD**) application for the Project, paying particular attention to (a) the assessment report of the Department of Planning, Industry and Environment (**DPIE**) dated June 2020 regarding the SSD application (**Assessment Report**); (b) key issues raised in public submissions during the public hearing; and (c) any other relevant documents or information.

3. The IPC has recently completed the public hearing, which was held on various days between 20 July 2020 and 1 August 2020. I have been asked to advise on a number of specific issues raised in the course of the public hearing, in particular the meaning and application of the principles of ecologically sustainable development (**ESD**); and the interpretation of clause 14 of the *State Environmental Planning Policy (Mining, Petroleum Production and Extractive Industries) 2007* (**Mining SEPP**).

4. Specifically, I am asked to advise on the following matters:

   (a) the consequence of the absence of express reference to the principles of ESD in the Assessment Report;

   (b) some of the contentions advanced in objector submissions dated 16 July 2020 made on behalf of the North West Alliance (**NWA Submission**) in respect of the application of the principles of ESD, in particular the proper application of:

   (i) the precautionary principle in relation to groundwater and ecological impacts; and

   (ii) the principles of "inter-generational equity" and "intra-generational equity" in relation to climate change and social and economic impacts;

   (c) the contention advanced in the NWA Submission about the Minister's "*Statement of Expectations for the Independent Planning Commission*" (applicable for the period from 1 May 2020 to 30 June 2021) and procedural fairness to the NWA;

   (d) the operation of clause 14 of the Mining SEPP; and

   (e) the submissions made during the public hearing to the effect that the SSD application must be refused as the Project has no "*social licence*", having regard to the matters that the IPC must consider under section 4.15 of the *Environmental Planning and Assessment Act 1979* (NSW) (**EP&A Act**).

Background

5. My instructing solicitors have informed me of the following background facts.

6. The Project is a joint venture between Santos NSW (Eastern) Pty Ltd (80%) and EnergyAustralia Narrabri Gas Pty Ltd (20%). Santos NSW (Eastern) Pty Ltd, a wholly owned subsidiary of Santos Limited, is the proponent of the SSD application and proposed operator of the Project.

7. Santos proposes to develop a new coal seam gas (**CSG**) field and associated infrastructure over 95,000 hectares in north-western NSW near Narrabri. This will involve the progressive installation of up to 850 gas wells on up to 425 well pads over approximately 20 years and the construction and operation of gas processing and water treatment facilities. While the Project area will cover about 95,000 ha, the Project footprint would directly impact about one per cent of that area (that is, up to 1,000 ha of cleared land).

8. The Project has the potential to produce up to 200 terajoules of natural gas per day for the domestic gas market over a period of at least 20 years. This would meet approximately 50% of NSW's gas demand.

9. The Project has been identified as a Strategic Energy Project in the NSW Gas Plan.

10. About two thirds of the Project site is located within the Pilliga State Forest, with the balance of the site situated on privately-owned agricultural land to the north of the Forest.

11. Currently there are approximately 70 gas wells and associated infrastructure installed within the Project area that have been used for exploratory purposes since the early 2000s.

Project Status

12. On 1 February 2017, Santos lodged State Significant Development application SSD-6456 (**SSD Application**) and the requisite Environmental Impact Statement (**EIS**) with the DPIE.

13. The SSD Application has been under assessment for over 3 years. Over 23,000 public submissions were received by the DPIE in relation to the SSD Application during this period.

14. On 11 June 2020, DPIE released its Assessment Report, which recommended approval of the SSD Application. Appendix I to the Assessment Report contains the draft recommended conditions of consent (**Recommended Conditions**).

15. As there were more than 50 unique public objections to the SSD Application,[1] the IPC was declared to be the consent authority for the SSD Application under section 4.5(a) of the EP&AAct. The SSD Application was referred to the IPC for determination on 11 June 2020.

16. The Project was also declared to be a controlled action under the *Environment Protection and Biodiversity Conservation Act 1999* (Cth) (**EPBC Act**) on 1 December 2014. A decision under the EPBC Act is expected to be made following the determination of the SSD Application by the IPC.

The public hearing

17. Following a request by the Minister under section 2.9(1)(d) of the EP&A Act, the Project was the subject of a public hearing that took place between 20-24 July and on 1 August 2020. The commissioners (Mr Steve O'Connor (Chair), Professor Snow Barlow and Mr John Hann) and counsel assisting the IPC (Richard Beasley SC) conducted the public hearing by telephone and video conference. Over 400 people registered to speak at the public hearing and numerous written submissions were made, including the NWA submission referred to above.

18. My instructing solicitors have drawn attention specifically to the following passages in the transcript of the public hearing, in particular to give context for the first question that I am asked to address in this opinion.

19. At the opening of the public hearing, Mr David Kitto on behalf of the DPIE presented an outline of the Assessment Report to the IPC and made a number of statements regarding the application of the precautionary principle to the Project, following questions by counsel assisting,[2] in which the application of ESD to the Project was discussed.

20. The exchange between Mr Beasley SC and Mr Kitto is quite lengthy so I do not set it out here, but I note that Mr Beasley put a series of propositions to Mr Kitto to clarify the way in which the principles of ESD had been applied to the Project. Some of the relevant considerations identified in this exchange include: the "natural reasons…the coal seam from which the gas is going to be extracted is a long way below the freshwater aquifers";[3] "the aquitards…the rock that…separates the – [sic] as a barrier between the freshwater and the coal seam";[4] "it's a seismically stable area";[5] "conditions";[6] "knowledge of the

1 Cl. 8A(1)(b) of the *State Environmental Planning Policy (State and Regional Development) 2011*.
2 Transcript, Day 1, P-18, line 18 through to P-23, line 10.
3 Transcript, Day 1, P-19, lines 36-38.
4 Transcript, Day 1, P-19, lines 43-44.
5 Transcript, Day 1, P-20, lines 1-2.
6 Transcript, Day 1, P-20, line 7.

geological architecture” (with the exchange discussing knowledge of faults or structures at a regional scale as against local faults and structures);[7] “the field development protocol and field development plan”;[8] the phasing of the development;[9] “monitoring and the fact that it’s independent monitoring at times”;[10] and “other precautions in the conditions”.[11]

21. Mr Kitto also made the following statement about the phasing of the development in relation to groundwater impacts:

> *And it’s a critical way of dealing with uncertainty and bringing in a whole lot of new information over time in a progressive way to deal with and manage any risks. But, fundamentally, as you pointed out earlier, I think what the Water Expert Panel and a lot of other experts have pointed out to us is that we are talking about localised uncertainties and risks, not uncertainties at a broad regional level that would lead to fundamental, you know, significant and irreversible harm. So if you go to the precautionary principle and you take the two strands that, you know, Judge Preston has outlined there, it’s – you first need to establish that there will be significant and irreversible harm…*[12]
>
> *… in our view, we don’t think the precautionary principle is triggered in this instance, and, you know, a lot of – a lot of the reasons why are probably best spelled out in the Water Expert’s Panel’s report, attached to our report and we’ve really summarised a lot of the findings from that expert advice in our assessment report.*[13]

22. Then there is the following exchange between the Chair and Mr Kitto:[14]

> *MR O’CONNOR: Okay. Just a question following on from Richard’s discussion with you moments ago about the precautionary principle. Looking through the department’s assessment report, I’m struggling to find where the ESD principles – the ecologically sustainable development principles – have been addressed by the department. Can you lead me to where that’s given some consideration?*
>
> *MR KITTO: So I – I mean, the principles of – I mean, the principles of ESD as they’re defined in New South Wales are the effective integration of economic, social and environmental factors. And our view is that the whole report is really*

[7] Transcript, Day 1, P-20, lines 18-39.
[8] Transcript, Day 1, P-21, lines 5-25.
[9] Transcript, Day 1, P-21, lines 34-35.
[10] Transcript, Day 1, P-22, line 46.
[11] Transcript, Day 1, P-21, lines 41-44.
[12] Transcript, Day 1, P-21, lines 46-47 and P-22, lines 1-7.
[13] Transcript, Day 1, P-22, lines 30-34.
[14] Transcript, Day 1, P-22, lines 34-46.

an attempt to integrate those aspects and, you know, ESD, you know, is not something that you can point and say it's in paragraphs 3, 4 and 5. It really is the whole report. Just – you know, and we're fully aware that, you know, under the public interest – the requirements to consider the public interest, that imports the objects of the Act.

23. Mr Kitto also stated:

> *And, you know, ESD is certainly one of the objects of the Act but there are also – you know, it's one of six objects that are relevant to the consideration of the project, and we haven't gone about the, you know, proper use of various – you know, all those other objectives. So, you know, we're quite happy to provide a very simple version of it but, as I said, our view is our whole report is about the effective integration of economic, social and environmental factors into decision-making. In terms of the principles of ESD, you know, the legislation does single out, you know, the precautionary principle as a potential way of achieving ESD.*[15]
>
> *You know, in our view, you know, there's two limbs to that under case law and, in our view, we have – none of our assessment has identified any potential significant or irreversible harm that would result from the project. And, in our view, the project does not trigger the precautionary principle. In terms of intergenerational equity, I think our assessment makes it clear that there are unlikely to be any significant impacts on people or the environment, and certainly there would be no – you know, the ability for the environment – you know, the future generation to be able to benefit and use the natural resources, and the environment in that area would not be compromised by the Narrabri Gas Project.*[16]

24. I note that a further exchange between counsel assisting and Mr Kitto on the topic of the precautionary principle occurred on Day 7 of the public hearing, which I have read and considered. It appears to me that the DPIE has consistently expressed the view, based on the materials that they identify and the reasoning set out in the Assessment Report, that the precautionary principle is not engaged in relation to groundwater, ecological impacts or otherwise, since there is no apparent significant risk of harm. Mr Kitto also addressed an alternative submission to the IPC, to the effect that assuming that the precautionary principle had been triggered, then adaptive management is an appropriate response to the identification of that risk, since the threat of harm is low or very low and the Project will advance incrementally.

15 Transcript Day 1, P-23, lines 1-9.

16 Transcript, Day 1, P-25, lines 10-20.

Advice

25. My opinion on the five topics raised for advice is as follows.

(a) The consequence of the absence of express reference to the principles of ESD in the Assessment Report

26. I am instructed that on a number of occasions during the public hearing, objectors contended that the IPC should draw an adverse inference from the absence of express references to the term "*ecologically sustainable development*" in the Assessment Report, the inference being that the DPIE had not considered or applied the principles of ESD; and the further inference being that there is thereby some legal defect in the report.

27. One of the 10 objects of the EP&A Act refers to ESD. The object set out in s 1.3(b) is:

> (b) to facilitate ecologically sustainable development by integrating relevant economic, environmental and social considerations in decision-making about environmental planning and assessment.

28. The term "*ecologically sustainable development*" is defined in s 4 of the EP&A Act to have the same meaning it has in s 6(2) of the *Protection of the Environment Administration Act 1991*, which provides:

> *(2) For the purposes of subsection (1) (a), ecologically sustainable development requires the effective integration of social, economic and environmental considerations in decision-making processes. Ecologically sustainable development can be achieved through the implementation of the following principles and programs:*
>
> *(a) the precautionary principle—namely, that if there are threats of serious or irreversible environmental damage, lack of full scientific certainty should not be used as a reason for postponing measures to prevent environmental degradation.*
>
> *In the application of the precautionary principle, public and private decisions should be guided by:*
>
> *(i) careful evaluation to avoid, wherever practicable, serious or irreversible damage to the environment, and*
>
> *(ii) an assessment of the risk-weighted consequences of various options,*
>
> *(b) inter-generational equity—namely, that the present generation should ensure that the health, diversity and productivity of the environment are maintained or enhanced for the benefit of future generations,*
>
> *(c) conservation of biological diversity and ecological integrity—namely, that conservation of biological diversity and ecological integrity should be a fundamental consideration,*

(d) improved valuation, pricing and incentive mechanisms—namely, that environmental factors should be included in the valuation of assets and services, such as:

(i) polluter pays—that is, those who generate pollution and waste should bear the cost of containment, avoidance or abatement,

(ii) the users of goods and services should pay prices based on the full life cycle of costs of providing goods and services, including the use of natural resources and assets and the ultimate disposal of any waste,

(iii) environmental goals, having been established, should be pursued in the most cost effective way, by establishing incentive structures, including market mechanisms, that enable those best placed to maximise benefits or minimise costs to develop their own solutions and responses to environmental problems.

29. In respect of State Significant Development, s 4.40 of the EP&A Act provides that s 4.15 applies (subject to Division 4.7) to the determination of a development application. Section 4.15(1) sets out the familiar list, requiring consideration of such of the listed matters as are of relevance to the development the subject of the development application.

30. The principles of ESD are not a listed matter in s 4.15(1). However, the Land and Environment Court has indicated that the requirement to consider the "*public interest*" picks up aspects of the principles of ESD relevant to the circumstances of a particular development application. In *Upper Mooki Landcare Inc v Shenhua Watermark Coal Pty Ltd and Minister for Planning* [2016] NSWLEC 6, (2016) 216 LGERA 40 at [178], Preston CJ of LEC held that the former Planning Asssessment Commission (**PAC**) was obliged to take into consideration the relevant matters of the precautionary principle and the principle of conservation of biological diversity and ecological integrity – that obligation "*arose as part of the required consideration of the public interest*". The relevant ground of challenge to the PAC's approval of the Watermark Coal Project in that case failed because "*PAC's obligation to consider these two principles of ESD did not demand consideration at the level of particularity and in the precise manner argued by the applicant in this ground of challenge*" (at [180]) and, in any event, the PAC had in substance considered the necessary matters (at [181]-[182]).

31. Nevertheless, proceeding on the basis that there is a generally applicable obligation to consider relevant principles of ecologically sustainable development, in my opinion it is not necessary to mention specifically the term ecololgically sustainable development or recite the specific text of the definition of that term in the determination of an application, let alone in an assessment report considering the application.

32. In *Drake-Brockmann v Minister for Planning* [2007] NSWLEC 490, (2007) 158 LGERA 349 at [132(7)], Jagot J said (making an assumption that the former Part 3A of the EP&A

Act obliged the Minister to consider the principles of ecologically sustainable development where relevant to the particular project) that:

> *In this context it was open to the Director-General to observe that his entire report generally represented an assessment of ecologically sustainable development. It was open to the Director-General to conclude that the project was consistent with the principles of ecologically sustainable development. It was open to the Minister to accept those conclusions. In so doing, the Minister considered ecologically sustainable development and its principles and programs as relevant to the project. The Director-General did not need to specifically mention the two principles and programs relied on by the applicant (the precautionary principle and inter-generational equity) to enable the Minister to consider those principles and programs and ecologically sustainable development generally.*

33. That paragraph was approved in *Haughton v Minister for Planning* [2011] NSWLEC 217, (2011) 185 LGERA 373 at [166]. Further, in *Minister for Planning v Walker* [2008] NSWCA 224, (2008) 161 LGERA 423 at [59], the Court of Appeal indicated that consideration of the principles of ESD does not require explicit formulation of issues in the terms of the four principles and programs specified in the definition of ESD.

34. Accordingly, in my opinion, assuming that the underlying fact in the question for advice is correct – that there is not any express reference to the term"*ecologically sustainable development*" in the body of the Assessment Report – in my opinion that fact does not have any material consequence. The relevant question, and the relevant obligation that is placed upon the consent authority in the determination of the development application, is to engage with the substance of the principles of ESD.

35. There can be no doubt from the exchanges set out above that Mr Kitto considers that the DPIE addressed and applied the substance of the principles of ESD in the course of its assessment of the Project. Having reviewed the Assessment Report, I consider that to be correct. In my opinion, there is evident objective support for that conclusion in the range of matters considered in the Assessment Report and the Recommended Conditions.

36. Three related points may be noted.

37. First, as Mr Kitto noted during the public hearing,[17] the Assessment Report also does not explicitly mention any of the other nine objects of the EP&A Act, despite their relevance to the assessment engaged in by the DPIE throughout the Assessment Report. In my view, as with the object of the EP&A Act that refers to ESD, it would be formalistic and wrong to insist on the use of specific terms or specific text in the preparation of an

[17] Transcript, Day 1, P-25, lines 1-4.

assessment report. It is sufficient if the DPIE (and the consent authority in due course) engages with the substance of the relevant principles.

38. Secondly, the requirement upon the consent authority to have regard to the public interest must be applied having regard to the scope and purpose of the EP&A Act.[18] There is no basis to assert that a single object of the EP&A Act, such as the principles of ESD, should be given any greater weight than the other objects. There is no "hierarchy" of objects to be observed or applied.[19] The two objects referred to in paragraph 25 of the NWA Submission are part only of the purpose of the EP&A Act and, in my opinion, it would be wrong to limit consideration to those two objects or otherwise adopt a process of assessment by which two of the ten objects of the EP&A Act are given dispropritionate weight.

39. Thirdly, the statutory expression of the object that refers to ESD, in s 1.3(b) of the EP&A Act, carries its own very generally expressed guide to achieving ESD – the object is to facilitate ESD "by integrating relevant economic, environmental and social considerations in decision-making about environmental planning and assessment". As Pepper J held in *Barrington - Gloucester - Stroud Preservation Alliance Inc v Minister for Planning and Infrastructure* [2012] NSWLEC 197, (2012) 194 LGERA 113 at [174]:

> … the level of generality at which these principles are considered does not, in my view, mandate any particular method of analysis nor the outcome that should result from any consideration (*Drake-Brockman* at [132(2)]). Thus descent to a direct application of the principles to each and every condition imposed in the approval is not required.

18 *Patra Holdings Pty Ltd v Minister for Land and Water Conservation* [2001] NSWLEC 265, (2001) 119 LGERA 231 at [9], [11].

19 *Drake-Brockman v Minister for Planning* [2007] NSWLEC 490, (2007) 158 LGERA 349 at [127].

(b)(i) The precautionary principle in relation to groundwater and ecological impacts

40. As I have noted in paragraph 30, there is authority that the principles of ESD (where issues relevant to those principles apply) are relevant matters for consideration as part of the 'public interest' that are required to be considered under s 4.15(1)(e) of the EP&A Act. See also *Telstra Corporation Ltd v Hornsby Shire Council* [2006] NSWLEC 133, (2006) 67 NSWLR 256 at [123] (***Telstra***); *Minister for Planning v Walker* [2008] NSWCA 224, (2008) 161 LGERA 423 at [42]-[43] (***Walker***).

41. The precautionary principle is one of the principles of ESD.[20] It is triggered where:

    (a) there is a threat of serious or irreversible environmental damage; and

    (b) scientific uncertainty as to the environmental damage (*Telstra*).

42. These thresholds are cumulative, in that each must be satisfied before the precautionary principle is invoked.

43. In applying the 'scientific uncertainty' test, Preston CJ of LEC in *Telstra* clarifies that complete certainty is an "*unattainable goal*" and therefore unrealistic. Accordingly, where scientific uncertainty exists:

    (a) the evidence of serious or irreversible harm;

    (b) the degree of that uncertainty; and

    (c) the steps proposed to be taken that can be reasonably taken to reduce or mitigate that uncertainty,

    must be considered.[21]

44. In my opinion, those propositions highlight a crucial omission from the NWA submission, which is the consideration of (c) above. Where full scientific certainty cannot be achieved, the precautionary principle does not prohibit granting consent to the project until certainty has been obtained.[22]

45. Adaptive management is an accepted and appropriate approach to managing scientific uncertainty, particularly when associated with potential groundwater impacts where the regional groundwater conditions are well understood.[23] In my opinion, in circumstances

20 Section 6(2)(a) of the *Protection of the Environment Administration Act 1991* (NSW).

21 *Telstra* at [141].

22 *Telstra* at [179]-[181].

23 Adaptive management regimes are regularly approved and regularly pass muster in the Courts. See, for example, *Barrington-Gloucester-Stroud Preservation Alliance Inc v Minister for Planning and*

in which an adaptive management regime is proposed to reduce or mitigate areas of scientific uncertainty, it is incumbent upon the consent authority to consider that regime when assessing an allegation that the proposed development is inconsistent with the precautionary principle. That obligation is explicity stated in *Telstra* at [141].

46. In *Newcastle & Hunter Valley Speleological Society Inc v Upper Hunter Shire Council and Stoneco Pty Limited* [2010] NSWLEC 48, (2010) 210 LGERA 126 (**Speleological Society**), the Court acknowledged that, in general, the imposition of an adaptive management regime as a way of managing the risks of significant environmental harm is accepted as appropriate (at [185]). At [184], Preston CJ of the LEC stated [emphasis added]:

> *Adaptive management is a concept which is frequently invoked but less often implemented in practice. **Adaptive management is not a "suck it and see", trial and error approach to management, but it is an iterative approach involving explicit testing of the achievement of defined goals**. Through feedback to the management process, the management procedures are changed in steps until monitoring shows that the desired outcome is obtained. **The monitoring program has to be designed so that there is statistical confidence in the outcome**. **In adaptive management the goal to be achieved is set, so there is no uncertainty as to the outcome and conditions requiring adaptive management do not lack certainty, but rather they establish a regime which would permit changes, within defined parameters, to the way the outcome is achieved**.*

47. I note that there have been a number of cases in the Land and Environment Court that have considered scientific uncertainty in relation to groundwater impacts.[24]

48. In *Hunter Environment Lobby Inc v Minister for Planning and Infrastructure (No 2)* [2014] NSWLEC 129, involving an objector appeal against a decision of the PAC to approve an open-cut coal mine, Pain J held that:

    (a) an adaptive management regime was capable of adequately addressing the impacts of the expansion on groundwater supplies (at [188]); and

Infrastructure [2012] NSWLEC 197, (2012) 194 LGERA 113; *Hunter Environment Lobby Inc v Minister for Planning and Infrastructure (No 2)* [2014] NSWLEC 129; *Upper Mooki Landcare Inc v Shenhua Watermark Coal Pty Ltd and Minister for Planning* [2016] NSWLEC 6, (2016) 216 LGERA 40; *Port Stephens Pearls Pty Ltd v Minister for Infrastructure and Planning* [2005] NSWLEC 426; *Tuna Boat Owners Association of SA Inc v Development Assessment Commission* (2000) 77 SASR 369.

[24] *Barrington-Gloucester-Stroud Preservation Alliance Inc v Minister for Planning and Infrastructure* [2012] NSWLEC 197, (2012) 194 LGERA 113; *SHCAG Pty Ltd v Minister for Planning and Infrastructure* [2013] NSWLEC 1032; *Hunter Environment Lobby Inc v Minister for Planning and Infrastructure (No 2)* [2014] NSWLEC 129.

(b) the precautionary principle does not require a zero risk approach, rather it requires a proportionate response, which can be achieved through appropriate conditions of consent, including, in that case, the adaptive management regime that was to be adopted (at [261]).

49. Of course, an adaptive management approach may be done well or it may be done poorly, and it may not always be an appropriate response to potential groundwater impacts in particular circumstances. In *SHCAG Pty Ltd v Minister for Planning and Infrastructure* [2013] NSWLEC 1032 (***SHCAG***), the Court in Class 1 proceedings found risks of groundwater contamination would not be adequately mitigated by the proposed adaptive management approach, which included a requirement to prepare and implement a water management plan as a condition of the approval.

50. Prior to the merit appeal in *SHCAG*, the Director-General's Environmental Assessment Report noted that the proponent had made various assumptions about present groundwater conditions, but that there was an "*absence of actual monitoring data to calibrate and confirm these assumptions [which] means that Boral's position cannot yet be confirmed*" (*SHCAG* at [69]). On appeal, the Court found that an adaptive management regime was inappropriate in circumstances where there were significant uncertainties and undefined parameters due to a lack of baseline data on water quality issues (at [86]). In other words, the proposed regime did not meet the test in *Speleological Society*.

51. In the present circumstances, the NWA Submission states that the IPC should engage the precautionary principle and refuse consent to the Project on the basis that "*there are risks of serious and irreversible environmental harm and a lack of scientific uncertainty as to that harm, particularly in relation to water impacts, and the proponent has failed to properly establish the environmental consequences, particularly in relation to water resources*".[25] Oral submissions made by subject-matter experts on behalf of the NWA on Day 4 of the public hearing were to the same effect. However, so far as I am aware, with the possible exceptions set out below, no attempt has been made in the NWA submissions on this topic to address the proposed adaptive management regimes, let alone to attempt to demonstrate any deficiency in the proposed steps to be taken to reduce or mitigate the scientific uncertainty.

52. With respect to those experts who presented their opinions to the IPC in support of the NWA submissions (as they are listed in paragraph 6 of the NWA Submission), this omission seems to have occurred persistently throughout all or most of the submissions of those technical experts. On the basis of the materials that I have reviewed, I have not

[25] NWA Submission at [41].

identified in any of those expert submissions an engagement with, and discussion of the effect of, the adaptive management regimes proposed in the EIS, assessed by the DPIE in the Assessment Report or reflected in the Recommended Conditions, with the possible following exceptions:

(a) The submission of Dr Ziller on social impacts. This submission suggests that the fact that the Social Impact Management Plan is required to "identify" social impacts, indicates that such impacts have not been assessed and that there are information gaps that do not facilitate an "adaptive management" approach to social impacts via the imposition of a condition requiring a Social Impact Management Plan. I note that this submission does not refer to paragraphs 556-595 of the DPIE Assessment Report, which indicate that consideration has been given to social impacts and that the intention in requiring the Social Impact Management Plan is to identify and document such social impacts so that they can be monitored to facilitate a responsive approach to those impacts over time.

(b) The submission of Matthew Currell on groundwater, which raises concerns regarding the adequacy of information to facilitate the adaptive management approach to groundwater impacts. That submission would need to be addressed in the context of consideration of the findings of the Water Expert Panel, GISERA and the IESC.

53. I turn now to consider some of the specific areas of concern addressed in the public hearing, in the context of considering the application of the precautionary principle.

Groundwater

54. The NWA Submission sets out various groundwater and surface water risks presented by CSG related activities.

55. The anticipated groundwater and surface water impacts of the Project have been reviewed in detail by the DPIE in the Assessment Report.

56. I am instructed that anticipated groundwater and surface water impacts of the Project have also been assessed over a number of years by three separate independent expert bodies, namely the:

(a) CSIRO (GISERA);

(b) Water Expert Panel; and

(c) Commonwealth Independent Expert Scientific Committee;

each of which has determined that the Project would not have a significant impact on groundwater and surface water having regard to the proposed comprehensive suite of conditions to be imposed on the Project.

57. I have been asked to consider whether, assuming that the following statements provide an accurate description of the substance of the SSD application in relation to groundwater, it is open to the IPC to consider that the proposed monitoring and adaptive management approach for the Project meets the description in *Speleological Society*:

(a) the potential impacts to groundwater sources have been rigorously assessed and found to be negligible. The model used to predict future impacts has been described as "world class" and "fit for purpose" by an independent peer review conducted by CSIRO. It will continue to be enhanced with further field monitoring data;

(b) although some level of uncertainty will always remain with respect to the modelling of groundwater impacts, an "adaptive management" approach has been adopted, as is widely accepted for resources projects, whereby there will be ongoing monitoring of water levels and pressures and water quality via a Water Management Plan;

(c) the baseline conditions are known to the extent that they can be through the groundwater model,[26] which will be continuously updated;

(d) remaining knowledge gaps can only be closed out by commencing the Project, updates to the groundwater model and through implementation of the Water Management Plan.[27] In addition, the water management performance measures prescribe performance measures for water impacts and on the aquifers, riparian and aquatic ecosystems, well integrity, produced water, irrigation and beneficial reuse management, Bohena Creek water discharges, salt management and chemical and hydrocarbon storage,[28] and through the collection of ongoing monitoring data;

(e) the Water Management Plan (which includes multiple sub-plans dealing with all aspects of water management) is to be developed in consultation with several key agencies and stakeholders and approved by the Planning Secretary. It incorporates an early detection system to ensure that any changes in groundwater which were not predicted are actioned well before there are any impacts to water users; and

(f) a Water Technical Advisory Group is being established to provide ongoing advice on all aspects of the project water-related management issues, including the groundwater model, Water Management Plan and the Field Development Plan.[29]

58. In my opinion, on the basis that the propositions set out above accurately reflect the facts, it is well open to the IPC to consider that the proposed monitoring and adaptive

26 Assessment Report, at [286]-[293], summarising the key findings of the Water Expert Panel.

27 Recommended Conditions, B37 and B38.

28 Recommended Conditions, B35.

29 Recommended Conditions, B36.

management approach for the Project meets the description in *Speleological Society*. To the extent that 'knowledge gaps' existed when the EIS was first prepared, and exist today, in relation to impacts on groundwater, on that basis I consider that it is open to the IPC to determine that it is appropriate for these to be dealt with as part of an adaptive management approach.

Ecological Impacts

59. The NWA Submission raises a series of concerns regarding the adequacy of the environmental assessment in relation to ecological impacts and cites concerns regarding deficiencies in the impact assessment.[30] The NWA Submission says that "uncertainty about the location of gas infrastructure as well as the scale of direct and indirect impacts has made a transparent assessment of the biodiversity impacts of this Project impossible".[31] For this reason, it is said that the precautionary principle is engaged and should be applied to refuse the SSD application.[32]

60. In my opinion, as with the groundwater issues, the NWA Submission identifies a range of potential impacts on ecological matters,[33] but does not also identify that those matters are the subject of proposed mechanisms to reduce or mitigate the feared harm.

61. A compliant assessment of the proposal requires attention to the mitigation measures that have been proposed and those that are required to be implemented by way of inclusion in the Recommended Conditions.

62. It is no part of this opinion to purport to carry out that assessment. However, in my opinion, it is critical to such an assessment to engage with the adaptive management regime that has been established to address the inevitable scientific uncertainty arising from a Project where the precise location of surface infrastructure is unknown and is guided by progressive exploration, appraisal and development. As one example among many, the proposed conditions of consent contain a requirement to prepare and implement a Field Development Protocol to dictate the siting of gas well infrastructure,[34] which is to occur in the context of the location and character of the Project area within the broader ecological context of the Pilliga State Forest and surrounding agricultural areas.

63. As another example, the NWA Submission does not address Recommended Conditions B40-B48, which appear to me to be directed to reducing or mitigating ecological impacts

30 NWA Submission at [86].

31 NWA Submission at [83].

32 NWA Submission at [87].

33 NWA Submission at [85].

34 Recommended Conditions, B2-B3.

of the proposed development. For example, Recommended Condition B47 requires the Biodiversity Management Plan to integrate with the Water Management Plan and Rehabilitation Management Plan.

64. In my opinion, if matters raised by technical advisers or expert witnesses are said to provide a basis for the invoking the precautionary principle, the relevant expert opinions ought to have assessed the relevant adaptive management regimes proposed in respect of the development application. Otherwise, the analysis will fall short of the consideration required, as *Telstra* at [141] makes clear.

(b)(ii) The application of the principles of "intergenerational equity" and "intragenerational equity" to the Project in relation to climate change and social and economic impacts

65. I have reviewed the summary in the NWA Submission on the principles of intergenerational equity and intragenerational equity at paragraphs [33]-[36] and generally agree with that summary so far as it goes. However, the NWA Submission does not address the limb of the principle of intergenerational equity that is described as the conservation of access principle.

66. It has been accepted that there are three fundamental principles underpinning the principle of intergenerational equity, namely (emphasis added):[35]

> *(i) the conservation of options principle which requires each generation to conserve the natural and cultural diversity in order to ensure that development options are available to future generations;*
>
> *(ii) the conservation of quality principle that each generation must maintain the quality of the earth so that it is passed on in no worse condition than it was received;*
>
> ***(iii) the conservation of access principle which is that each generation should have a reasonable and equitable right of access to the natural and cultural resources of the earth.***

67. In my opinion, the NWA Submission does not acknowledge or address the third limb of the principle of intergenerational equity. Further, to the extent that the NWA Submission is taken to contend that no new fossil fuel projects should be approved at all, it is evidently a more straightforward matter to make such a submission in reliance only on the first two limbs, and ignoring the third. The conservation of access principle appears to me to pull firmly in the other direction. All three limbs of the principle of

[35] *Gray v Minister for Planning* [2006] NSWLEC 720, (2006) 152 LGERA 258 at [119], citing an academic paper of Preston CJ of LEC.

intergenerational equity ought to be considered in any application of this aspect of the principles of ESD.

Climate Change

68. I am asked to address the proposition advanced by some objector submissions concerned with climate change that the IPC should adopt a position that there should be no new approvals for fossil fuel development.

69. The NWA Submission argues that the approval of the Project at the current time is contrary to the principle of inter-generational equity because of the cumulative impact of greenhouse gas (**GHG**) emissions from the Project, which is inconsistent with the carbon budget approach towards climate stabilisation and the Paris Agreement climate target. The NWA Submission states that the Project's contribution to cumulative climate change impacts means that its approval would be inequitable for current and future generations.[36]

70. The submission of Professor Penny D. Sackett, summarised and adopted in the NWA Submission,[37] and the tenor of many others who spoke at the public hearing, is the idea that no new fossil fuel development can be approved. To be fair to those who made objections in such terms, it may be assumed that many of them were advocating a particular outcome rather than suggesting that the necessary outcome of a lawful consideration of the SSD application is its refusal.

71. However, it appears to me that the NWA Submission does not engage with the particular circumstances of the SSD Application and the likely impact that this Project would have on climate change. Rather, it appears to endorse an approach that does not take account of relevant government policy,[38] and which was explicitly rejected in *Gloucester Resources Limited v Minister for Planning* [2019] NSWLEC 7, (2019) 234 LGERA 257 (***Rocky Hill***). Adopting the approach apparently advocated in the NWA Submission would make impermissible a class of developments that are currently permissible in a range of locations throughout NSW under a range of planning instruments. If a consent authority were to take such as approach – for example by concluding that based on the carbon budget approach as described by Professor Sackett,[39] no new fossil fuel developments could be approved under any circumstances – I consider it would not be complying with the statutory framework by which the development application must be determined.

36 NWA Submission at [75].

37 At [74].

38 Which may be considered in accordance clause 14(2) of the Mining SEPP.

39 Transcript, Day 4, P-49, line 24 to P-51, line 2.

72. The contention that there be no new fossil fuel developments approved was raised and rejected in *Rocky Hill*. In *Rocky Hill,* the contribution that the GHG emissions of the proposal would make to climate change was not the essential reason for refusal. The significant unacceptable planning, visual and social impacts of the proposed development in that case were by themselves considered to be sufficient reasons to refuse the application.[40] In considering the 'carbon budget' approach, the Court described this as a "policy decision" and held that "*the better approach is to evaluate the merits of the particular fossil fuel development that is the subject of the development application to be determined*".[41]

73. In my opinion, no court has endorsed the principle or policy that no new fossil fuel developments ought to be approved. On the contrary, there are recent examples of primary decisions to approve fossil fuel developments being upheld in court: see for example *Australian Coal Alliance Inc v Wyong Coal Pty Ltd* [2019] NSWLEC 31. Whether or not a new fossil fuel development ought to be approved is a question that falls to be determined by consideration of the facts of the particular development in the context of the applicable law, which in my view does not include any principle or policy that no new fossil fuel developments ought to be approved.

74. The IPC's task, therefore, is to assess the SSD Application on the evidence available before it. In this regard, I note that the EIS sets out the results of the assessment by Santos of GHG emissions, including Scope 1, Scope 2 and Scope 3 emissions.[42] In my opinion, the consideration by the IPC of that material ought to be done in the context of its overall consideration of the merits of the proposal under section 4.15 of the EP&A Act, without being bound by a "policy decision" such as that cautioned against in *Rocky Hill*.

75. I note that the materials provided to the IPC in the Assessment Report include consideration of the application of the principles of intergenerational equity and intragenerational equity to the issue of climate change. This issue has been considered throughout the assessment of the Project and in the EIS as stated by Mr Kitto on Day 1 of the public hearing.[43]

<u>Social and Economic Impacts</u>

76. The NWA Submission at [78]-[81] makes a number of statements regarding social impacts, with one short statement on economic impacts at [82]. An opinion of Dr Alison Ziller in relation to social impacts is also cited at [81]. The basis on which the NWA

40 At [556].

41 At [552]-[553].

42 Appendix R of the EIS, summarised in Chapter 24.

43 Transcript, Day 1, P-25, lines 13-18; EIS pages 32-7 to 32-8.

Submission finds any fault with the assessment of these issues in the Assessment Report is not apparent. The NWA Submission does not provide particular reasons for thinking that the principles of intergenerational equity and intragenerational equity are breached.

77. I am instructed to address this issue on the basis that it is open to the IPC to make the following findings about the impacts of the proposed development in relation to social and economic impacts:

(a) The Project will impact very few sensitive receivers / landowners;

(b) The Project will be carried out in an area that is already the subject of mining activity and CSG appraisal activities. Access agreements are already in place between Santos and several landowners. (This is to be contrasted to the town of Gloucester, which is relatively 'pristine' and shielded from existing mining activity. It is also to be contrasted with the Warkworth Extension Project, which would have expanded mining close to the town of Bulga);

(c) The dust impacts, and arguably also the visual impacts, of CSG operations are significantly less than a coal mine. Surface infrastructure is minimal and will have relatively low visual impact;

(d) Unlike a coal mine, where the location of the mine is dictated by the location of the resource, CSG can be accessed from various locations and surface infrastructure can be located to avoid or mitigate adverse impacts; and

(e) No property acquisition conditions are proposed for the Project. Mitigation measures are proposed in relation to only a handful of sensitive receivers. This is to be contrasted with the project conditions in *Bulga Milbrodale Progress Association Inc v Minister for Planning and Infrastructure and Warkworth Mining Limited* [2013] NSWLEC 48, (2013) 194 LGERA 347 (***Warkworth LEC*)** where, for example, 20 properties had automatic acquisition rights on the basis of noise impacts, a further 41 had automatic mitigation rights, and there was the potential for all privately owned land in Bulga to be acquired "*if the noise generated at the Mount Thorley-Warkworth mine complex causes sustained exceedances*" of the noise criteria.[44]

78. If the IPC were to accept the matters set out in paragraph 77, in my opinion those matters would provide a sound basis for distinguishing the present application from the conclusions made about social and economic impacts in the decisions *Warkworth LEC* and *Rocky Hill*.

44 *Warkworth LEC* at [376].

(c) The Minister's "*Statement of Expectations for the Independent Planning Commission*" and procedural fairness to the NWA

79. The NWA Submission asserts that the Minister's "*Statement of Expectations for the Independent Planning Commission*" (applicable for the period from 1 May 2020 to 30 June 2021) creates expectations of the IPC that are "*bad in law*".

80. Specifically, the NWA Submission contends:

> *The Minister's Statement of Expectations states that he expects the IPC 'to make decisions based on the legislation and policy frameworks and informed by the Planning Secretary's assessment'. To the extent that this statement seeks to depart from the text of s 4.15, it is bad in law…*
>
> *Further, the Statement of Expectations states that the Minister encourages the IPC to "seek guidance from the Planning Secretary to clarify policies or identify policy issues that may have implications for State significant development determinations*." *Again, this statement is inconsistent with the proper role of an independent IPC, which is required to determine the Project according to law, and not by reference to any guidance from the Planning Secretary on policy issues that may have implications for the Project.*[45]

81. As any reasonable reader of the Minister's statement will observe, there is nothing in the Statement of Expectations that suggests that:
    (a) the IPC should depart from the consideration required by the EP&A Act, including s 4.15 as applied by s 4.40; or
    (b) that the Planning Secretary's assessment should be given dispositive weight; or
    (c) that seeking policy guidance from the Planning Secretary is mandatory or that the Project should not be determined in accordance with law.

82. In my opinion, the NWA Submission does not provide any grounds for thinking that the Minister's Statement of Expectations is invalid or "*bad in law*".

83. The NWA Submission also suggests that the objectors to the Project have been denied procedural fairness to date because the IPC has met privately with supporters of the Project, namely the proponent, the Department and Narrabri Shire Council, but has not met with those groups, including NWA, its members, or members of the community who oppose the Project.

84. I am instructed that:

[45] NWA Submission at [20]-[21].

(a) those who object to the Project have had the opportunity to make written submissions to the IPC and to be heard for oral submissions during the assessment of the Project application, including in the course of a 7-day public hearing, in which a minimum 5 minutes speaking time was given to each speaker;

(b) in particular, the NWA (represented by counsel and the technical advisers formally engaged by it) was given the opportunity to make oral submissions for a total of 175 minutes during public hearing, in addition to its written submissions;

(c) the objectors have had the opportunity to inform themselves about the information presented at the meetings between the IPC and Santos, the DPIE, Narrabri Shire Council, the Water Expert Panel and the other agencies, by means of the availability of complete copies of the transcripts of all of those meetings;

(d) the objectors have had the opportunity to make oral and written submissions on the matters discussed at those meetings.

85. In my opinion, those facts do not demonstrate any denial of procedural fairness to the NWA, its members or other objectors.

(d) The operation of clause 14 of the Mining SEPP

86. Clause 14(1)(c) of the Mining SEPP provides:

> *Before granting consent for development for the purposes of mining, petroleum production or extractive industry, the consent authority must consider whether or not the consent should be issued subject to conditions aimed at ensuring that the development is undertaken in an environmentally responsible manner, including conditions to ensure the following –*
>
> …
>
> *(c) that greenhouse gas emissions are minimised to the greatest extent practicable.*

87. Clause 14(1)(c) provides for an express mandatory consideration: the consent authority "*must consider*" the identified topic, which is "*whether or not the consent should be issued subject to conditions aimed at ensuring that the development is undertaken in an environmentally responsible manner*", including conditions of the identified character.

88. In my opinion, it would be an error of law to construe clause 14(1)(c) as if it required the proponent to minimise GHG emissions to the greatest extent practicable.

89. Clause 14(2) of the Mining SEPP states:

> *Without limiting subclause (1), in determining a development application for development for the purposes of mining, petroleum production or extractive industry, the consent authority must consider an assessment of the greenhouse gas emissions (including downstream emissions) of the development, and must do so having regard to any applicable State or national policies, programs or guidelines concerning greenhouse gas emissions.*

90. In circumstances in which it applies, cl 14(2) imposes a double duty: to consider an assessment of greenhouse gas emissions *and* to do so having regard to applicable State or national policies, programs or guidelines concerning greenhouse gas emissions.

91. Clause 14(2) has been the subject of authoritative consideration in the Land and Enviornment Court in *Wollar Progress Association Incorporated v Wilpinjong Coal Pty Ltd* [2018] NSWLEC 92 (***Wollar***). Among other things, the issue of whether the NSW Climate Change Policy Framework was applicable to the task under cl 14(2) was determined in *Wollar* and the Court held that it was not: see at [147]-[148] and [183].

(e) Submissions to the effect that the SSD Application must be refused as the Project has no "*social licence*"

92. I have reviewed the transcript of the public hearing and observe that an objection frequently made was that the absence of a 'social licence' for the Project was a reason for the SSD Application to be refused.

93. The term 'social licence' does not appear in any statute or legislative instrument that the IPC is called upon to consider or apply for the purposes of determining the development application for the Project. It does not have any special or accepted meaning in planning and environmental law. I am not aware of judicial consideration of the term in NSW courts in the context of the interpretation or application of NSW planning and environmental laws.

94. In other contexts. courts have noted the ambiguous meaning of the term. In the context of an injunction regarding a claim for misleading and deceptive conduct, in *No TasWind Farm Group Inc v Hydro-Electric Corp (No 2)* [2014] FCA 348, the Court said, at [38]:

> *… I harbour considerable doubt that what is conveyed by the notion of "social licence" can be identified with such precision as would enable a court to conclude that any particular practice fell within or outside of its scope. It seems to me arguable that the notion of "social licence" may be better understood as construct*

of social and political discourse rather than of law and that it is potentially too amorphous and protean in nature to be applied as the criterion for a judicial declaration.

95. To the extent that submissions about 'social licence' might be thought to raise considerations related to the "public interest" under section 4.15(1)(e) of the EP&A Act, in my opinion the only safe course is to abandon any gloss on that statutory provision and instead apply the words of the statute. In that regard, the consideration of the 'public interest' operates at a "high level of generality" and does not require the consent authority to have regard to any particular aspect of the public interest.[46]

Richard Lancaster SC

7 August 2020

[46] *Minister for Planning v Walker* [2008] NSWCA 224; (2008) 161 LGERA 423 at [41]; *Pittwater Council v Minister for Planning* [2011] NSWLEC 162 at [141].

ACIL ALLEN CONSULTING

REPORT TO
SANTOS (EASTERN) PTY LTD
6 AUGUST 2020

NARRABRI GAS PROJECT

UPDATE OF THE ECONOMICS

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EXECUTIVE SUMMARY

This report provides an update of the economic analysis prepared for the Environmental Impact Statement (EIS) for the Narrabri Gas Project (NGP) that was released in 2016 and subsequent reviews. Specifically, ACIL Allen performed the following:

— **Gas market developments and modelling the impact of the NGP on gas prices**: This involved reviewing the key developments in the eastern Australian gas market since the 2016 EIS report and how that has affected the competitiveness of the NGP. Gas market modelling was also performed to assess how gas prices in eastern Australia might be impacted by the development of the NGP.

— **Economic impact assessment**: This assessment consisted of two pieces of analysis – a revised cost benefit analysis and re-modelling the macroeconomic benefits of the NGP taking into account the revised capital cost estimates and recent labour market factors.

Gas market developments and the impact of the NGP on gas prices in NSW

Key market developments and recent price trends

The outlook for demand for natural gas in the eastern Australian gas market is driven by the demand from the three Queensland LNG projects of around 1,500 PJ per annum and the relatively flat domestic demand profile of the domestic market (estimated 2020 consumption of around 546 PJ). The Australian Energy Market Operator (AEMO) suggests, in its 2020 Gas Statement of Opportunities report, that gas supplied from developed, undeveloped and anticipated fields will only be sufficient to meet demand until around 2026. Additional gas resources, including from 2C contingent resources, will be required to meet demand after that time.

The ACCC also concluded, in its January 2020 Gas Inquiry Interim Report, that there was a risk of a shortfall of supply in the southern states from 2024 onwards unless more production from contingent gas resources is developed.

The major benefit from the NGP would be increasing competition in the eastern Australian gas market. This would be particularly important over the medium to long term, as production from existing fields declines and supply from contingent resources is needed. After new sources of supply in the Gippsland Basin, the NGP is the next cheapest source of supply from 2C contingent resources as indicated in the supporting documentation to AEMO's 2020 Gas Statement of Opportunities report. Furthermore, with these Bass Strait sources likely to be much smaller sources of supply, the Narrabri project is the cheapest large source of supply, important to placing downward pressure on gas prices during the latter years of the 2020s and through the 2030s.

Other sources of supply have also been proposed to help meet the shortfall risk including LNG import terminals. However, over the longer term the price of LNG is likely to exceed the cost of Narrabri gas including transmission costs. Relevant LNG forward pricing curves already foreshadow this occurring.

Short term spot market gas prices in eastern Australia increased from around 2016 for a number of reasons. Actual supply was lower than anticipated from Gippsland basin producing fields and from delays and closures of other fields in the southern states. This happened at the same time that low cost ramp gas was being absorbed into the LNG export facilities in Queensland. Spot prices rose to as high as $14 per GJ in 2016 and stayed between the $7 per GJ to $11 per GJ level until around September 2019, when they fell as a result of new supply coming on stream in Australia and from weaker international LNG demand due to a historically warm northern hemisphere winter (which resulted in Queensland LNG exporters diverting more supply to the domestic market). Spot prices have then continued lower in the first half of 2020 primarily due to weak demand in part due to the COVID-19 pandemic. However, as demand in Australia recovers and international LNG markets (particularly in Asia) rebalance, spot market prices in Australia are expected to rise over the coming years.

More importantly, prices in long term gas supply agreements (GSAs) in eastern Australia (which reflects the price of the majority of gas traded in the market) also rose as the impact of LNG netback pricing fed through into the domestic market due to the development of LNG export projects in Queensland, that have not yet reached combined full capacity. There has therefore been an alternative market to the domestic market. In its January Gas Inquiry Interim report, the ACCC suggests that the average commodity price in GSAs for supply in 2020 is expected to be around $8.52 per GJ from producers in Queensland and $9.73 per GJ from producers in the southern states. Prices from retailers in the southern states in 2020 are expected to be higher, settling between $10.22 per GJ and $10.95 per GJ.

The development of new supply sources is fundamentally important to meeting future demand and providing supply at prices that are affordable for small and large consumer groups in eastern Australia. This is especially the case for regions such as New South Wales that are almost entirely reliant on gas imported from other states.

Impact of NGP on gas prices

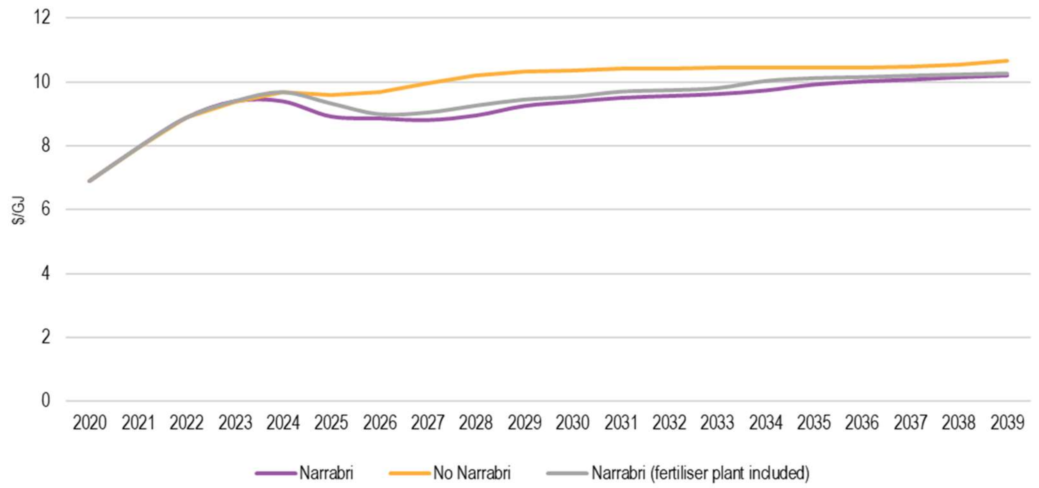
Various factors affect gas prices at any point in the eastern Australian gas market, including the price tolerances of consumers, producers' marginal costs of production, and the optimal operation of the gas transportation network. It is the interaction between these factors that determines gas prices at any location across the market.

ACIL Allen's GasMark model is based on an assumption that the eastern Australian gas market operates as a single pool market, connecting supply sources with customer loads through the interconnected network of transmission pipelines. It is a theoretical model that does not take into account the impact of gas contracts on delivered prices year on year. Nevertheless, it is a useful tool for indicating price paths that would influence contract prices as they are renegotiated over time.

The modelling undertaken by ACIL Allen shows that gas prices in Sydney could potentially be between 4 per cent and 12 percent lower from 2025 onwards over the 25-year evaluation period with the NGP, than without it (See Figure ES 1). The main benefit for prices is through the late 2020s and early 2030s when NGP reaches full production and as the market progressively moves towards higher volumes of 2C contingent resources.

The NGP also increases competition in the eastern Australian gas market. This is key factor in maintaining downward pressure on gas prices. Santos has committed to allocating all production to the domestic market. Santos has indicated that it is in discussions with a party that is considering establishing a fertiliser plant in Narrabri if the NGP proceeds. The plant would draw 40 TJ per day of gas from the project or about 20 per cent of the projects output. The modelling shows that the impact on wholesale gas prices in Sydney would be slightly less with the fertiliser plant than without it. The price reduction in Sydney is estimated at around 3 per cent to 9 per cent over the 2025 to 2046 period (See Figure ES 1).

FIGURE ES 1 PROJECTED WHOLESALE SPOT PRICE IN SYDNEY WITH AND WITHOUT THE NGP (REAL 2020 DOLLARS)



SOURCE: ACIL ALLEN CONSULTING

In addition to the potential price benefit of the NGP, a key non-price factor is security of supply and long-term availability of supply. This is especially important for commercial and industrial customers. The NGP is likely to be in a position to offer large volumes of gas on long term contracts. This has been difficult in recent times due to the tightness in supply and the relatively modest competition in the upstream sector.

With the commitment made by Santos to make all the gas produced from the NGP available for the domestic market (75 PJ per annum), a new competitive source of supply close to Sydney is expected to lead to more competitive prices on long term gas contracts, particularly as the market moves into the late 2020s and 2030s.

Benefit cost analysis

The benefit cost analysis (BCA) has been updated for the reduction in the estimate of capital costs based on Santos' drilling experience in Queensland and South Australia. The BCA analysed benefits and costs accruing to the project over 25 years for a base case and five alternative scenarios, to test the sensitivity to assumptions. The alternative scenarios were in line with those required in the guidelines for economic assessment of CSG projects issued by the NSW Government.

The benefits and costs in each year were discounted to 2021-22 to calculate a net present value and a benefit cost ratio. The assumptions made for the five alternative scenarios were:

- discount rates 4 per cent and 10 per cent compared to 7 per cent for the base case
- production levels 10 per cent lower
- reduced gas prices - 10 per cent, 20 per cent and 30 per cent
- production levels and gas prices reduced by 10 per cent
- capital costs increased by 10 per cent.

Each case was estimated for a self-generation option and a grid-supplied option.

The revised NPVs for the project compared to the NPVs in the EIS supplementary report are as follows:

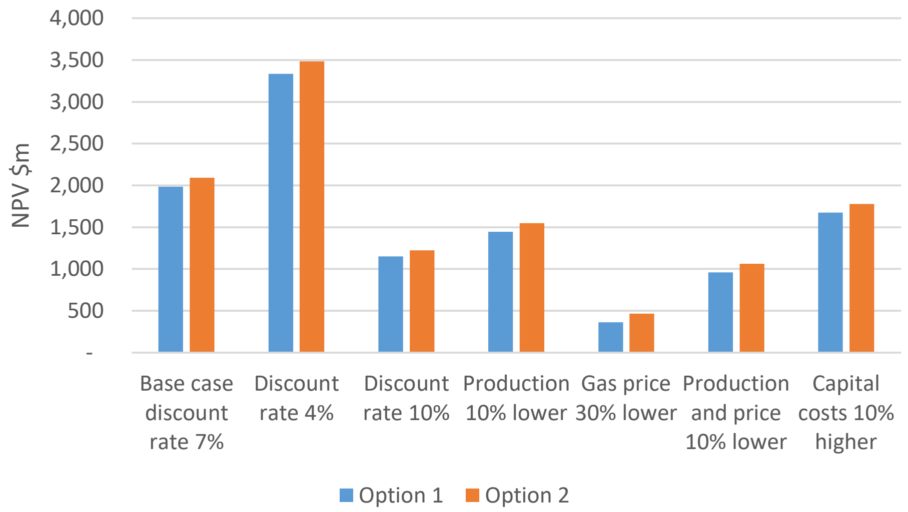
- $1,985 million compared to $1,535 million for the self-generated electricity option
  - 29 per cent higher than in the original EIS.
- $2,088 million compared to $1,639 million for the grid-supplied electricity option
  - 27 per cent higher than in the original EIS.

The revised benefit cost ratios compared to the original benefit cost ratios are as follows:

- 1.58 compared to 1.39 for the self-generated option in the original EIS
- 1.62 compared to 1.43 for the grid-supplied option in the original EIS.

The results of calculations are shown in Figure ES 2.

FIGURE ES 2 BASE CASE AND SENSITIVITY TESTING



Note: The only change to the calculations was lower capital costs.

SOURCE: ACIL ALLEN CONSULTING, (SANTOS, 24 APRIL 2018)

In the supplementary report, submitted on 24 April 2018, Santos noted that the only negative NPV arose with the 30 per cent reduction in gas prices. With the revised capital cost estimates, all scenarios had positive NPVs.

The overall impact of the reduced capital costs has been to increase the NPV of all options. Under the revised cost, all NPV results are positive.

Regional and macroeconomic benefits

The original macroeconomic and regional analysis was conducted using Tasman Global, ACIL Allen's Computable General Equilibrium (CGE) model. Tasman Global was again used to re-estimate the macroeconomic and regional impacts of the project with the lower capital costs.

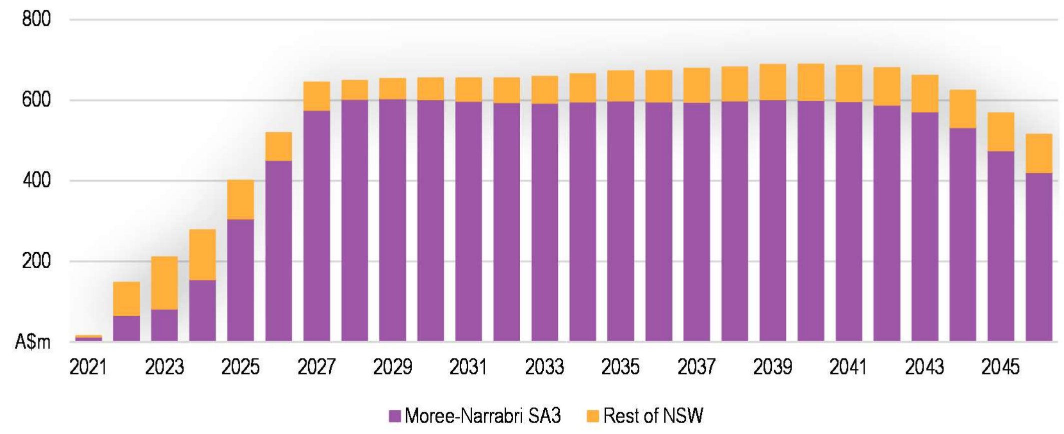
Two important assumptions were made in the original analysis. The first was that the overall employment in Australia was constrained. This assumption meant that any additional demand for employment created by the project had to come from elsewhere in the economy. This assumption reflected labour market conditions at the time and is no longer appropriate. Accordingly, ACIL Allen reduced the severity of this constraint in the re-modelling.

The second assumption was that the project would have no impact on gas prices as it was assumed that it would substitute for other gas supplies available at the time. ACIL Allen did not adjust gas prices in the remodelling. However, if lower gas prices had been taken into account, the economic benefits to consumers in the eastern Australian gas market would be higher.

Impact on real economic output and real incomes

The impact on real economic output over time is shown in Figure ES 3. The figure shows the distribution of additional real economic output between the Moree-Narrabri region and the rest of NSW.

FIGURE ES 3 REAL ECONOMIC OUTPUT



SOURCE: ACIL ALLEN CONSULTING

The results for real economic output and income are summarised in Table ES 1.

Over the 2021 to 2046 period, real economic output is 14 per cent higher for the Moree-Narrabri region and 23 per cent higher for NSW than in the original EIS.

Over the same period, the accumulated increase in real income in NSW is 38 per cent higher for the Moree-Narrabri region and 36 per cent higher for NSW than in the original EIS.

Relaxing the national employment constraint facilitated growth in economic activity and income in the Moree-Narrabri region and NSW.

TABLE ES 1 PROJECTED CUMULATIVE CHANGE IN REAL ECONOMIC OUTPUT AND REAL INCOME IN EACH REGION AS A RESULT OF THE NARRABRI GAS PROJECT RELATIVE TO THE BASE CASE ($2016)

	Real economic output			Real income		
	Total (2021 to 2046)	Net present value* 4%	7%	Total (2021 to 2046)	Net present value* 4%	7%
	2016 A$m	2016 A$m	2016 A$m	2016 A$m	2016 A$m	2016 A$m
Moree-Narrabri SA3 region	12,610	7,430	5,253	833	1,083	403
Rest of NSW	2,019	1,260	946	7,331	1908	3,154
Total NSW	**14,628**	**8,690**	**6,199**	**8,164**	**4,908**	**3,548**

SOURCE: ACIL ALLEN. NOTE: * THE USE OF THE 4 PER CENT AND 7 PERCENT ARE CONSISTENT WITH NSW GOVERNMENT GUIDELINES

Job creation

Over the life of the NGP, it is projected that an average of 912 full time equivalent direct and indirect jobs will be created in New South Wales (an increase of 78 per cent over the earlier estimate). More specifically, it is projected that the Narrabri Gas Project will increase employment (by place of residence) in the Moree-Narrabri region by an average of 222 FTE job years each year over the life of the project (an increase of 17 per cent over the earlier estimate).

These increases are in part a result of the reducing the severity of the constraint in national employment growth assumed in the earlier modelling and using the standard Tasman Global labour market framework.

Industry Impacts

The average impacts over the life of the NGP on industry employment and output at the regional and state levels are shown in Table ES 2. The results demonstrate that on both employment and output levels, the impacts of the NGP are positive for most of the sectors shown. The negative impacts shown to agriculture and forestry are small and are mainly due to an assumed reduction in farmland, competition for labour and small increases in local costs. These are relative changes from a baseline with no NGP and do not imply an absolute contraction in employment or output in the agricultural sector.

The positive benefits seen for the construction industry are a result of demand from the NGP, while wholesale and retail trade will benefit not only from project demand but from increased levels of income at the regional and state levels.

Due to its domestic sales orientation, modest direct employment demand and relatively low land requirements, the NGP has relatively little potential to have detrimental effects on NSW industries at the regional and state level. The positive demand and income effects offset potential negative effects.

TABLE ES 2 INDUSTRY EMPLOYMENT AND OUTPUT IMPACTS OVER THE PROJECT LIFE – PER CENT DEVIATION FROM THE BASELINE

	Employment		Output	
	Moree-Narrabri SA3 region	NSW	Moree-Narrabri SA3 region	NSW
Agriculture and forestry	-0.15	-0.03	-0.01	-0.01
Mining	0.05	0.02	0.04	0.02
Manufacturing	0.58	0.01	0.68	0.01
Utilities	0.15	0.01	0.24	0.00
Construction	0.82	0.01	0.66	0.01
Wholesale and retail trade	0.73	0.03	0.77	0.01
Transport	0.92	0.02	0.89	0.01
Services	0.74	0.02	0.70	0.00
TOTAL	**0.45**	**0.02**	**0.40**	**0.01**

SOURCE: ACIL ALLEN

Conclusion

The situation in the east Australian gas market has changed somewhat since the original EIS documentation was completed between 2016 and 2018. The current outlook for the east Australian market includes a potential shortfall in supply from existing and undeveloped fields from 2016 and potentially earlier in the southern states.

Increasingly the southern states will require development of contingent onshore resources as the existing developed and underdeveloped reserves are depleted. By the later 2020's and beyond, the NGP will be among the lower cost contingent resources.

ACIL Allen' modelling shows that the NGP can place downward pressure on gas prices in NSW, as represented by prices in Sydney.

The revised benefit cost analysis shows that the project demonstrates a positive NPV for the base case and the five scenarios adopted for sensitivity testing. The NPV for the base case is 29 per cent higher for the self-generated option than in the original EIS and 27 per cent higher for the grid supplied option.

The CGE modelling shows that the aggregate real economic output generated over the 2021 to 2046 period is 14 per cent higher for the Moree -Narrabri region than in the original EIS and 23 per cent higher for NSW.

The number of jobs created for NSW is 17 per cent higher in the Moree-Narrabri region than in the original EIS and 78 per cent higher for NSW. This increase is a result of relaxing the national employment growth constraint in the modelling done for this update.

Growth in employment and output across industries overall also higher than in the original EIS. The rate of employment growth in the mining and manufacturing sectors is positive in the current assessment whereas it was slightly negative in the earlier assessment. It is important to note that the slightly negative result for agriculture is relative to the situation without the NGP and does not reflect an absolute decline in employment or output for that sector.

1

INTRODUCTION

This report has been prepared for Santos Energy Limited. It provides an update of the economic analysis prepared for the Environmental Impact Statement (EIS) for the Narrabri Gas Project (NGP) that was released in 2016 and subsequent reviews.

The EIS comprised the following documents relevant to this review:

— Chapter 27 of the EIS and two Appendices (Santos, 2016)
  – Appendix U1 – Economic assessment Cost Benefit Analysis
  – Appendix U2 – Macro Economic Analysis
— Response to Submissions submitted by Santos (page 6-253). (Santos, 2017)
— Review of the economic assessment by BAE Economics dated 29 June 2017 (BAEconomics, 29 June 2017)
— Supplementary submission submitted by Santos in response to questions raised by BAE Economics dated 24 April 2018 (Santos, 24 April 2018)
— A final review by BAEconomics dated 5 October 2018. (BAEconomics, 5 October 2018).

The economic analysis was carried out in line with the following guidelines:

— Guideline for the use of Cost Benefit Analysis in Mining and Coal Seam Gas Proposals (NSW Treasury 2000)
— Handbook of Cost-Benefit Analysis (Commonwealth Department of Finance 2006)
— Guidelines for the Economic Assessment of Mining and Coal Seam Gas Proposals (NSW Department of Planning and Environment 2015).

The overall scope of work is to provide a contemporary final overview of the East Coast gas market. The review refreshes the economics in the light of the observation that the projects capital cost has been reduced in line with experience Santos has gained from projects in Queensland.

This report is set out in the following Chapters:

— Chapter 2 provides an update of the state of the east coast natural gas market
— Chapter 3 discusses gas procurement and gas pricing in the Eastern Australian Natural Gas Market
— Chapter 4 examines the impact of the NGP on gas prices in New South Wales
— Chapter 5 provides an update on the benefit cost analysis (BCA)
— Chapter 6 provides an update of the macroeconomic analysis.

UPDATE ON THE EASTERN AUSTRALIAN NATURAL GAS MARKET

2

The following sections provide an overview of the Eastern Australian Gas Market and examines recent demand and supply issues, the policy developments that have occurred and the implications of these developments for domestic gas prices. The analysis indicates that additional gas supplies will be needed in the southern states of the eastern Australian gas market after 2026. It also shows that the marginal cost of gas at this time will be higher than in the past as more expensive undeveloped and contingent gas resources are developed.

2.1 The Eastern Australian Gas Market

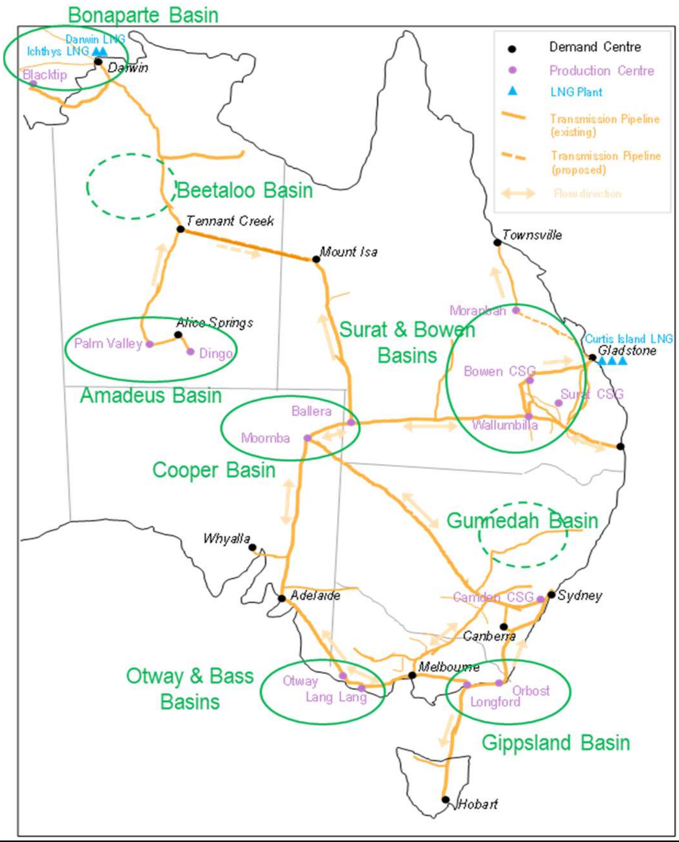
The structure of the Eastern Australian Gas Market, the main supply sources, demand centres and transmission pipelines together with the net flow directions on those pipelines is shown in Figure 2.1.

The market is physically connected across an area from Mount Isa in the north to Hobart in the south, and from Gladstone and Brisbane in the east to Adelaide and Whyalla in the west. The recently constructed Northern Gas Pipeline (Tennant Creek to Mount Isa) further extends the geographic scope of this interconnected market by tying in the Northern Territory which is a small domestic gas market but is potentially an important supplier to the eastern States.

There are a number of indicators that the gas supply system illustrated in Figure 2.1 now behaves more like a single integrated market than has been the case in the past. The market is characterised by physical interconnection of the transmission pipeline system, increased levels of interstate gas trade, an increased role for aggregators, correlated price trends in regional short-term trading markets and the emergence of gas swap arrangements that facilitates substitution of different sources of gas supply to meet contractual delivery commitments in an efficient manner.

A relatively recent development, that reflects the increasingly integrated nature of the eastern Australian market, is the modification of several transmission pipelines to support bi-directional flow. The South West Queensland Pipeline (including QSN Link from south west Queensland to Moomba), Roma to Brisbane Pipeline, Moomba to Sydney Pipeline (part), Victorian Transmission System (part) and Moomba to Adelaide Pipeline, are all now capable of flowing gas in either direction, providing shippers with the opportunity to move gas flexibly across the market.

FIGURE 2.1 EASTERN AUSTRALIAN GAS MARKET MAP



SOURCE: ACIL ALLEN CONSULTING

Most wholesale gas is sold and transported under bilateral agreements between producers, pipeline owners, retailers and major users. There are also six gas trading markets operated by the Australian Energy Market Operator (AEMO). These are the Victoria Declared Wholesale Gas Market, Sydney, Adelaide and Brisbane short-term trading markets and voluntary trading hubs at Wallumbilla and Moomba). Despite the emergence of these short-term trading platforms, the eastern Australian market continues to operate primarily based on long-term bilateral contracts, with the spot markets used largely to manage operational and contract imbalances.

2.2 Demand

Over the past decade there has been an unprecedented transformation of the eastern Australian gas market, driven by large-scale export LNG developments and associated upstream coal seam gas (CSG) field production facilities in Queensland. Three separate LNG export projects, with a combined production capacity of more than 25 million tonnes per year of LNG, were commissioned between late 2014 and late 2016. These facilities have a combined gross gas requirement of around 1,500 PJ/a—around triple the amount of gas currently used in the entire eastern Australia domestic gas market (excluding LNG).

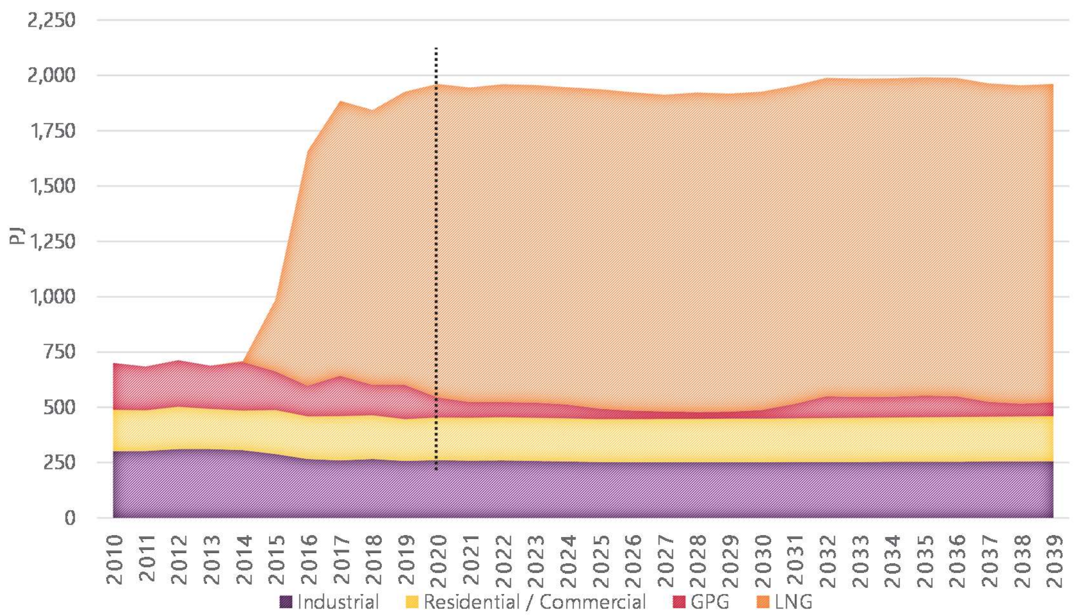
The outlook for demand for natural gas in the eastern Australian gas market is shown in Figure 2.2. Domestic demand is projected to decline from 546 PJ per annum from 2020 to around 522 PJ per annum by 2039. The key aspects of this outlook are:

— Residential and commercial is expected grow from 192 PJ/a in 2020 to 204 PJ/a by 2039.

— Industrial demand is expected to be relatively flat at around 252 PJ/a over the period

— Gas Power Generation demand is likely to decline from 92 PJ/a in 2020 to 30PJ/a by 2028 because of increasing variable renewable energy in the grid. It is then projected to increase post 2030 as coal fired power stations reach the end of their commercial life.

FIGURE 2.2 2020 GSOO EAST COAST GAS CONSUMPTION



SOURCE: (AEMO, FEBRUARY 2020)

While the annual demand is a useful indicator for supply adequacy, peak demand is also an important consideration. The 2020 GSOO also provided comment on trends in maximum daily demand (MDQ) as follows:

- NSW
  - MDQ projected to increase in the coming 5 years driven by new connections
  - MDQ expected to moderate post 2025 because of increased energy efficiency and fuel switching leading to a relatively flat long-term trend.
- Queensland
  - MDQ is forecast to decline to 2025 excluding LNG and GPG, as a result of reduction in industrial consumption and then increase slightly for the remainder of the forecast period.
- South Australia
  - MDQ is forecast to remain relatively flat to 2024 and then decline slightly due to energy efficiency and fuel switching offset by increased connections.
- Victoria
  - MDQ is projected to remain flat to 2025, a consequence of energy efficiency and fuel switching, and then increase as new connections grow.
- Tasmania
  - MDQ projected to increase driven by new connections and in an increase in industrial growth

2.3 Supply

2.3.1 Concerns about short term gas supplies 2016 to 2017

LNG developments have seen the rapid expansion of gas production from CSG fields in Queensland. A large part of the gas production capacity in Eastern Australia has now been committed to supplying the LNG projects on a long-term basis. This includes not only the Queensland CSG projects controlled by the LNG proponents, but also large volumes of third-party gas reserves that are now committed, under long-term contracts, to supply additional gas for LNG production.

In March 2017, AEMO's Gas Statement of Opportunities (GSOO) forecasted gas shortfalls could emerge in some states from 2019. The drivers of this potential shortfall were attributed to be a reduction in gas production for the domestic market from 600 PJ in 2017 to 478 PJ in 2020 and an increase in the demand for gas for LNG exports amounting to 1,430 PJ per year by 2020.

In September 2017, AEMO and the ACCC released reports showing that forecast gas shortfalls in the eastern gas market were expected to occur in 2018. The deterioration in the outlook for the supply-demand balance in 2018 was due to a downward revision to forecast production and an upward revision to GPG demand of over 50 per cent.

Following these reports, the Australian Government and east coast LNG exporters signed a Heads of Agreement in October 2017 designed to ensure secure supply for the eastern gas market. Under the agreement LNG exporters committed, in the event of a domestic shortfall, to offer uncontracted gas to the domestic market before selling this gas internationally. A new Heads of Agreement was signed in October 2018. Under the Heads of Agreement, the producers agreed to offer up to 183 PJ of gas in excess of their current commitments to domestic buyers on competitive market terms. These initial steps helped alleviate the anticipated shortfall and reduce spot prices at the time by around 25 per cent.

According to a press release from the Minister for Resources and Energy:

"Getting more supply into the market firms up gas security and lowers prices for our manufacturers and households. For instance, the ACCC found that prices offered for gas supply in 2019 are in the $8 to $11 a gigajoule range. That's in stark contrast to prices offered in the first half of 2017, when domestic gas offers were above international prices, peaking at offers as high as $22 a gigajoule in March 2017."[1]

A number of policy developments were also initiated since that time to address concerns about domestic gas supplies. These are outlined in Box 2.1. The measures have involved steps to improve the policy environment for the exploration and development of onshore gas, improve the transparency of the gas market, improve the efficiency of the gas transportation network and provide policy support for new gas supplies for NSW.

The latest short-term outlook contained in the 2020 GSOO is more optimistic about supplies in the short term but identifies emerging concerns from around 2024 onwards. This is the subject of the following discussion.

[1] Media release by the Minister for Resources and Northern Australia, 30 September 2018.

BOX 2.1 POLICY DEVELOPMENTS SINCE 2017

ACCC Gas Market Inquiry

The Inquiry was commissioned in 2017 and has been extended until 2025. The Inquiry issues interim reports every six months. The last interim report was issued in January 2020.

Australian Domestic Gas Security Mechanism (ADGSM)

The ADGSM relies on the Australian Government's export control powers under the Constitution to intervene if the domestic market was at risk. This mechanism has not been triggered.

COAG work on gas market transparency measures

Governments are working to increase transparency in the gas market. This includes continuing reforms through the COAG Energy Council requiring improved transparency from gas producers and LNG exporters on prices, reserves and resources.

Gas pipeline regulation

A consultation RIS on options to improve pipeline regulation was released on 1 November 2019. This review builds on previous reforms to pipeline regulation led by the COAG Energy Council. These past reforms include the introduction of a day-ahead auction of contracted but un-nominated pipeline capacity, standardisation of provisions in gas transportation agreements to make capacity more tradeable, and development of a capacity trading platform to facilitate sales and publication of information on secondary trades.

Gas acceleration program

In 2017, the Government announced its $26 million Gas Acceleration Program (GAP) which aims to accelerate the responsible development of onshore gas for domestic consumers. The program encourages direct investment in gas developments.

Emergency supply measures

COAG National Gas Emergency Response Advisory Committee responds to gas supply interruptions that affect more than one jurisdiction, managing communication across industry and government during major natural gas supply shortages. AEMO's Contingency Gas arrangements balance physical supply and demand in short term trading markets in the event that normal market mechanisms are unlikely to achieve this balance.

AEMO Gas supply guarantee

In March 2017, production facility operators and pipeline operators made commitments to the Australian Government to make gas available to meet peak demand periods in the National Electricity Market (NEM). The Gas Supply Guarantee is a mechanism developed by the gas industry to facilitate the delivery of these commitments. It comprises new processes to identify, assess and confirm a potential gas supply shortfall as well as processes to communicate with industry and to call for a response to a shortfall.

Victorian Government gas exploration policy

Victoria removed the ban on exploration for conventional gas while maintaining a permanent ban on fracking and coal seam gas exploration.

MOU between Commonwealth and NSW Government to secure additional gas for NSW

Under the MOU the governments agreed to facilitate an additional 70 PJ of gas per year into the NSW gas market. Potential projects under consideration include: the Narrabri Gas Project; an import terminal at Port Kembla; and an import terminal at Newcastle.

SOURCE: (DIIS, JANUARY 2020) (MINISTER FOR RESOURECES, 16 JUNE 2020):

2.3.2 The current supply outlook

The 2020 GSOO assessment of resources available to supply the Eastern Australian Gas Market was 97,637 PJ broken down as follows:

- 15,090 PJ classified as 2P developed
- 22,303 PJ classified as 2P undeveloped
- 59,600 PJ classified as 2C contingent.

Reserves range from 1P to 3P, with 2P being the most commonly reported measure of gas that is economic to develop in current market conditions. Resources are defined as 2C contingent resources which represent estimates of gas resources located in Australian gas basins but are deemed to be uneconomic to extract according to current market conditions.

AEMO notes that 2P reserves decreased by 12.3 per cent compared to 2019 estimates. The largest factor in this decrease was a decrease in 2P undeveloped resources. Contingent resources (2C) increased by 2.3 per cent as a result of the downgrading of some 2P reserves and the upgrade of some prospective resources (very early estimate of possible gas resources).

A tabulation of reserves and resources published by AEMO as part of the 2020 GSOO is shown in Table 2.1. These data are based on analysis prepared by Core Energy Group. AEMO adjusted the total figures quoted above following consultations with producers. The table provides insights into the sources of future gas for the eastern Australian Gas Market.

A major concern in the supply situation is the decline in production from existing fields in the southern states and the need to call on 2P undeveloped and 2C contingent reserves to meet future demand in the southern states.

TABLE 2.1 RESERVES AND RESOURCES BASED ON CORE ENERGY GROUP DATA PUBLISHED BY AEMO (PJ)

Basin	Project	2P Developed	2P Undeveloped	2C	Prospective resources
Queensland		-	-		
Galilee	Galilee	-	-	2,417	622
Surat & Bowen	Surat / Bowen / Denison Conventional	69	53	120	-
Surat & Bowen	Moranbah	219	38	5,548	-
Surat & Bowen	QLD CSG - Arrow Energy (excl. Moranbah)	520	5,941	15,887	10,807
Surat & Bowen	QLD CSG - QCLNG	3,963	4,761	13,700	8,586
Surat & Bowen	QLD CSG - GLNG	1,397	4,492	1,355	-
Surat & Bowen	QLD CSG - APLNG	4,406	5,859	4,244	-
Surat & Bowen	QLD CSG - Other	176	1,130	3,832	-
Cooper[1]	Cooper Eromanga Basin	757	252	5,850	144,564
Subtotal		11,507	22,527	52,953	164,580
Northern Territory					
Amadeus	Mereenie	93	93	193	3,604
Bonaparte	Blacktip	804	-	-	-
Subtotal		896	93	193	3,604
Southern States					
Bass	Bass Basin	70	210	70	-
Sydney	Camden	28	-	-	-
Otway	Casino, Henry and Netherby	50	78	36	-
Clarence Moreton	Clarence Moreton	-	-	303	14,700
Gippsland	GBJV & Turrum & Kipper	1,119	1,154	686	4,062
Gippsland	Gippsland - Non-GBJV	-	-	3,526	4,696
Gunnedah	Gunnedah	-	-	971	3,502
Otway	Halladale/Blackwatch/Speculant	25	-	-	-
Gippsland	Longtom & Sole	-	328	130	50

Basin	Project	2P Developed	2P Undeveloped	2C	Prospective resources
Otway	Otway Gas Project	121	328	216	2,691
Subtotal		1,413	1,888	5,868	29,701
Total		13,824	24,718	59,085	197,885

1. Part of the Cooper Basin is in South Australia. However, as most of these reserves are directed to LNG exports they have been included in the northern category.

Note: These data are based on analysis by Core Energy Group and published by AEMO. AEMO adjusted the total figures quoted in the text above based on additional consultations with producers. Totals may not add due to rounding errors.

SOURCE: (AEMO, FEBRUARY 2020)

AEMO adopted four gas supply and infrastructure project classifications for further analysis of the supply situation. These are:

— existing projects
— committed projects – all approvals have been obtained and implementation is ready to commence or is underway
— anticipated projects – developers consider the project to be justified based on a reasonable forecast of commercial conditions and a reasonable expectation that all necessary approvals will be obtained, and final investment decisions made. – the category includes 2P undeveloped reserves and selected 2C resources
— uncertain projects - these projects more uncertain or at early stages of development. Uncertain projects include uncertain to see contingent and perspective resource is that are accessible by existing pipeline and processing infrastructure.

Using these categories, AEMO compiled production forecasts from 2020 to 2024 as shown in Table 2.2 . Compared to the 2019 GSOO forecasts, production in the southern states has decreased for 2020 and 2021 but is the same in 2022. Compared to the 2019 GSOO, declining production in southern states is driven by total committed Victorian production reducing from 318 PJ in 2022 to 201 PJ in 2024 (representing a 37 per cent fall).

TABLE 2.2 GSOO PRODUCTION FORECASTS TO 2024 (PJ)

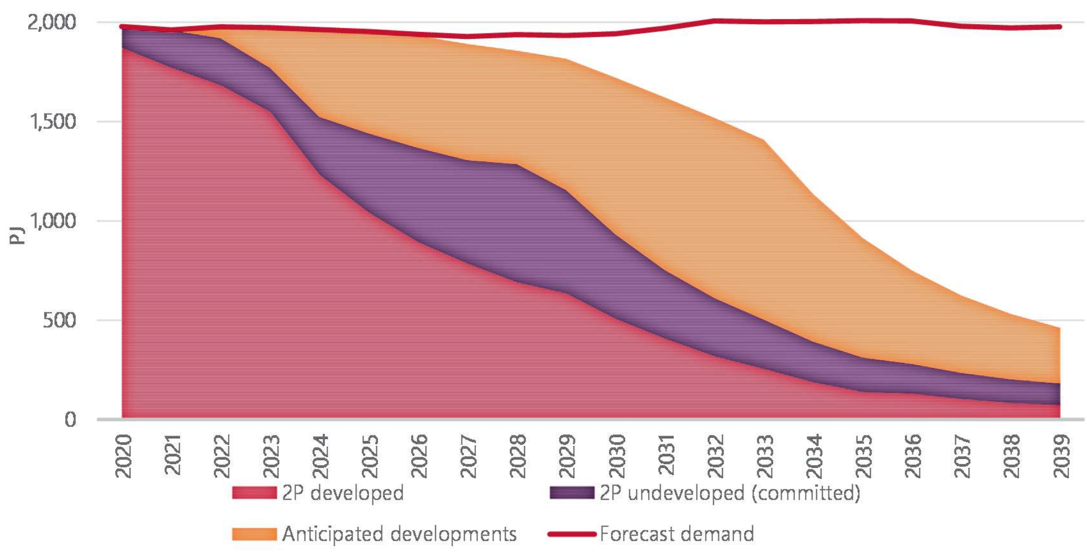
	Commitment criteria	2020	2021	2022	2023	2024
VIC / NSW / SA	Existing and committed	437	395	384	323	267
	Anticipated	22	69	72	123	106
	Total	460	464	456	447	373
	Difference from 2019 GSOO	**-15**	**-16**	**0**	**N/A**	**N/A**
QLD / NT	Existing and committed	1,566	1,525	1,489	1,371	1,261
	Anticipated	5	48	177	252	313
	Total	1,572	1,577	1,676	1,636	1,590
	Difference from 2019 GSOO	**+34**	**-16**	**+69**	**N/A**	**N/A**
Total east coast gas production		**2,031**	**2,041**	**2,132**	**2,083**	**1,963**
Difference from 2019 GSOO		**+18**	**-32**	**+69**	**N/A**	**N/A**

SOURCE: (AEMO, FEBRUARY 2020)

2.4 Supply demand balance

The 2020 GSOO finds that supply from existing and committed gas developments will be sufficient to meet gas demand across eastern and South eastern Australia until at least 2023 provided export spot cargoes are redirected to meet domestic demand if required. Furthermore, if anticipated gas field projects are developed, resource adequacy improves until at least 2026. The annual supply and demand balance as estimated by AEMO is shown in Figure 2.3.

FIGURE 2.3 ANNUAL SUPPLY AND DEMAND BALANCE EAST AUSTRALIAN GAS MARKET

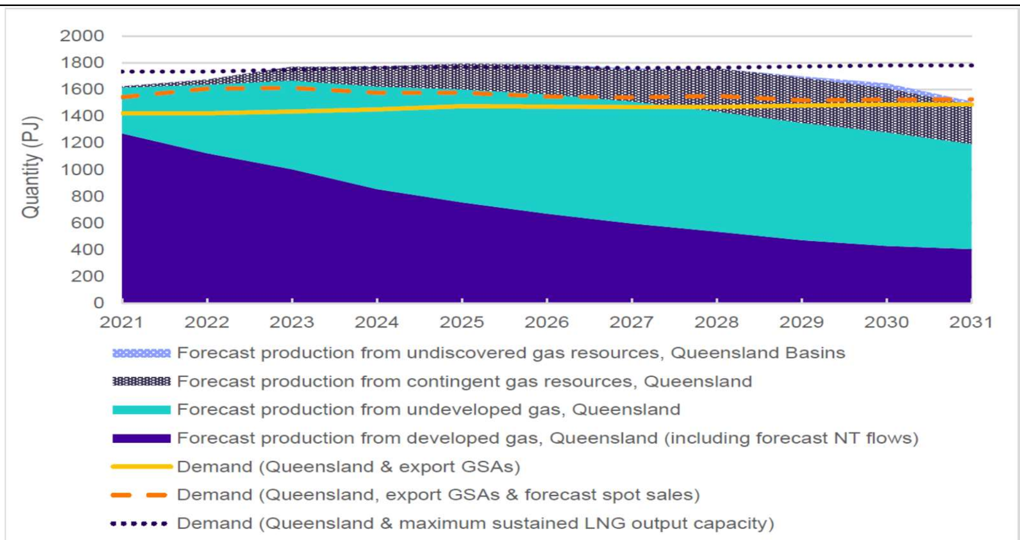


SOURCE: (AEMO, FEBRUARY 2020)

The chart shows that in total, gas from anticipated resources undeveloped and selected contingent resources, will be required to ensure sufficient annual supply from 2022 onwards. However, additional gas development will be required after 2026 to meet longer term demand.

In its Gas Market Inquiry Interim Report, issued in January 2020, the ACCC broke this analysis down into demand and supply between Queensland and southern states in the Eastern Australian Gas Market (ACCC, January 2020). Figure 2.4 shows the supply and demand balance as estimated by the ACCC for Queensland. The chart shows that supply in Queensland is expected to be sufficient to meet Queensland demand and maximum LNG output for most of the period. However, production from contingent resources will be required from around 2022 onwards.

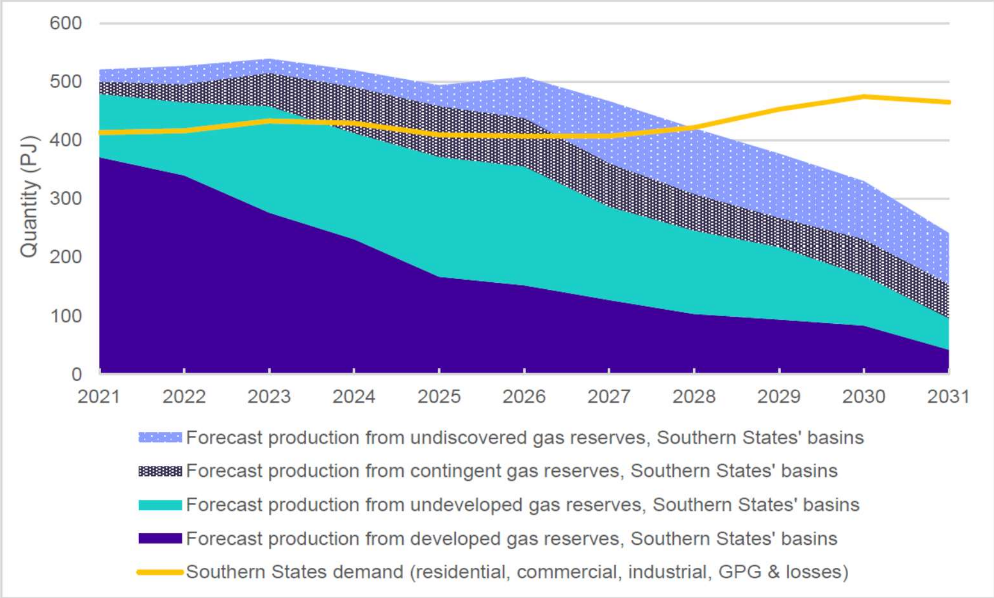
FIGURE 2.4 PROJECTED SUPPLY AND DEMAND IN QUEENSLAND



Source: (ACCC, January 2020)

The long-term supply demand outlook for the southern states is shown in Figure 2.5. The figure shows that on current projections, there is a risk of a shortfall in the southern states from 2024 onwards unless more production from contingent gas resources is developed.

FIGURE 2.5 PROJECTED SUPPLY AND DEMAND IN SOUTHERN STATES



SOURCE: (ACCC, JANUARY 2020)

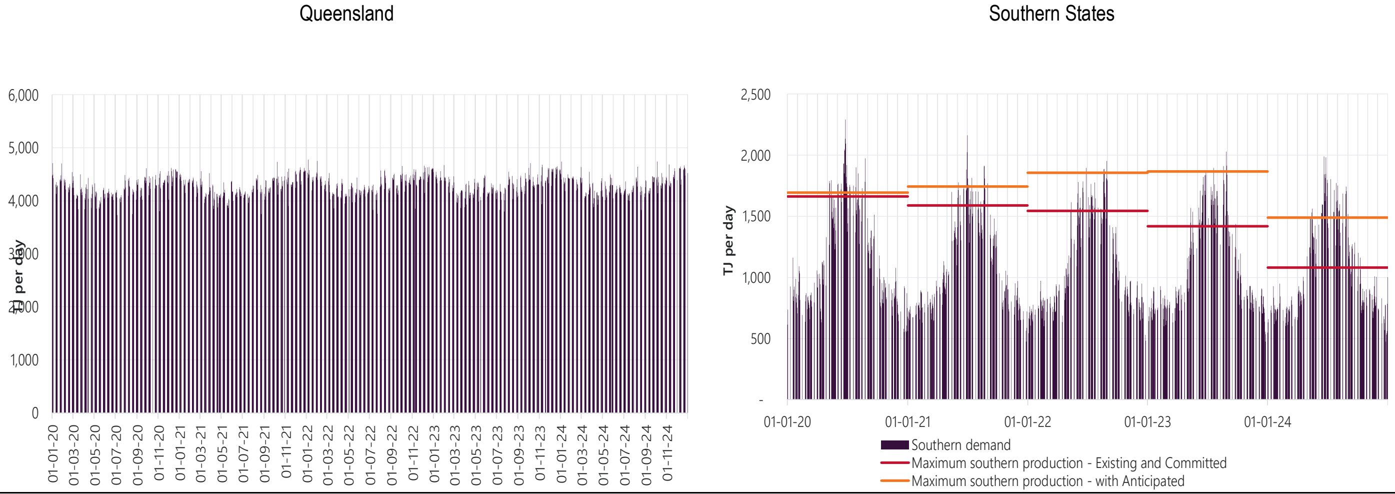
The chart shows a rapid decline in production from developed reserves. This reflects declining production from the Gippsland and Otway Basins. The Southern States will increasingly need to rely on undeveloped and contingent reserves in the south as well as gas from Queensland, the Cooper Basin and the Northern Territory for domestic supply.

When considering supply adequacy, it is also important to consider peak day demand because as fields decline, their ability to meet maximum daily quantities (MDQ) also declines.

The projected daily demands in Queensland and in the Southern States are shown in Figure 2.7. The figure shows that Queensland gas demand has much less seasonal variation than the southern states. In Queensland, LNG export demand normally occurs in winter which offsets Queensland domestic demand peaks that normally occur in summer.

Demand in the southern states however peaks in winter and there is no offsetting industrial demand to flatten the load profile. In aggregate the southern fields are forecast to experience up to 18,000 TJ difference between maximum and minimum demand across the year.

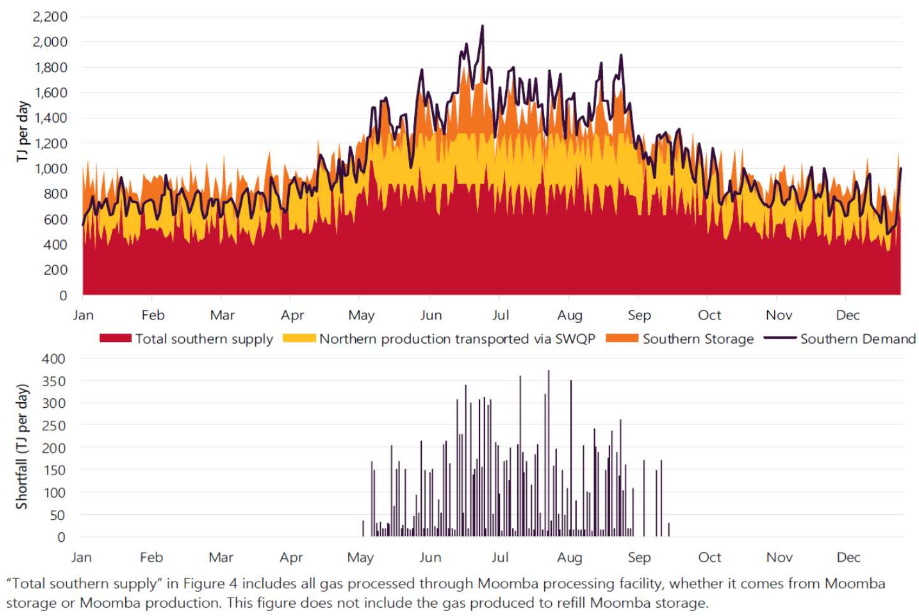
FIGURE 2.6 PROJECTED DAILY DEMAND



SOURCE: (AEMO, FEBRUARY 2020)

Figure 2.7. shows a potential supply gap in the southern states in the winter of 2024, of up to 400 TJ as peak production within in insufficient to meet forecast maximum daily demand.

FIGURE 2.7 DAILY SUPPLY DEMAND BALANCE IN SOUTHERN STATES IN 2024 WITH EXISTING AND COMMITTED PROJECTS.



SOURCE: (AEMO, FEBRUARY 2020)

Underground gas storage and Queensland CSG are likely play an increasingly important role in meeting peak day demand in the southern states. However, overall supply from southern fields or from LNG import terminals may also play an important part in meeting peak demands in winter in the southern states.

3 GAS PROCUREMENT AND PRICING

This chapter reviews the issues that influence gas procurement and pricing in the eastern Australian gas market. It reviews recent findings of the most recent Interim Report released by the ACCC on its Gas Market Inquiry and the role and behaviour of the short-term spot markets and the longer-term gas contracting arrangements. It notes that while the recent falls in spot prices reflect short term market pressures, bids and offers under longer term gas sales agreements appear to be priced in the $8 per GJ to $12 per GJ range. It also discusses the drivers of LNG prices and opines that the longer-term LNG price is likely to lie in this range over the longer term.

3.1 The nature of the market

Most wholesale gas in the eastern Australian gas market is sold and transported under bilateral agreements between producers, pipeline owners, retailers and major users. AEMO also operates several wholesale markets, including the Declared Wholesale Gas Market (DWGM) in Victoria and Short-Term Trading Markets (STTM) in Brisbane, Sydney and Adelaide. There is also Gas Supply Hub (GSH) that supports trade and movement of gas between regions. GSH participants trade short term physical gas products at pipelines in Wallumbilla and Moomba.

The gas supply system in eastern Australia behaves more like a single integrated market with physical interconnection of transmission pipelines, short term trading markets and swap arrangements allowing substitution of different sources of gas supply to meet contractual delivery commitments.

The factors that affect gas prices at any point include consumers' price tolerances, producers' marginal costs of production and the optimal operation of the gas transportation network. It is the interaction between these factors that determines the gas price at any location. In a perfectly operating pool market, the most economically efficient outcome at any point in time would be when supplies are allocated so that consumer and producer surplus is maximised taking into account network transmission costs[2].

However, the market is not a pure pool market. Individual contract arrangements are also a key factor in price outcomes over time.

3.2 Spot market pricing

Spot market prices are published by AEMO for the DWGM and the three STTMs on a daily basis. The spot prices provide an indication of short-term and seasonal variations in the supply demand balance and bear little relationship to long-term contract prices.

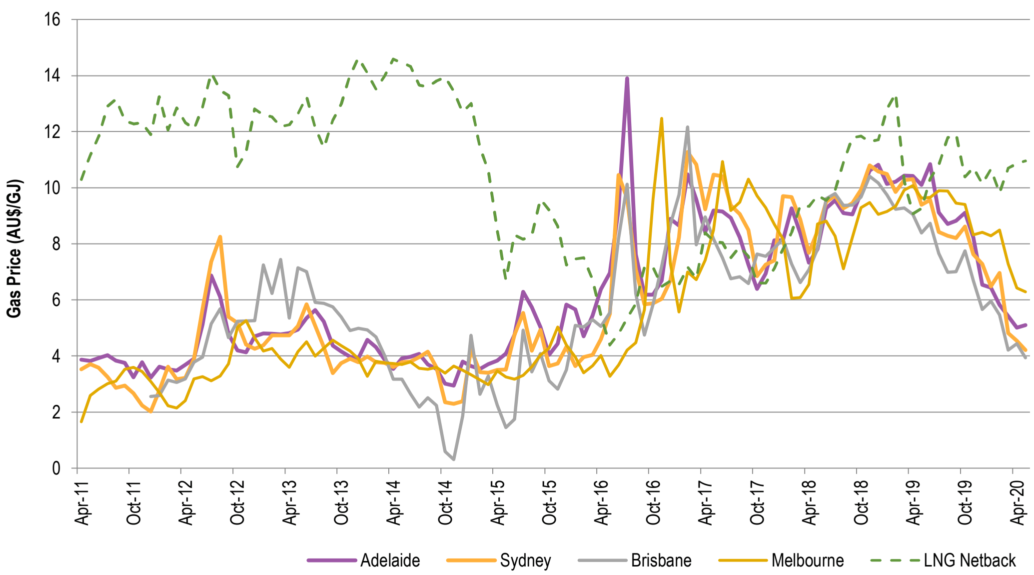
[2] Consumer surplus is the difference between the price a consumer is prepared to pay and the market price. Producer surplus is the difference between the market price and the cost of production.

Spot price are shown in Figure 3.1. Spot prices decreased in the years leading up to 2016, due in part to the availability of ramp gas in the lead up to the commissioning of the LNG plants in Queensland. Spot prices then increased in 2016-17. There were several factors that contributed to this including a faster drop off in supply from the Gippsland basin than expected, bans and/or moratoria on gas developments in NSW and Victoria, lower than expected production from CSG fields in Queensland and the withdrawal of ramp gas from the market.

Spot prices in 2018 and 2019 retreated somewhat from the peak prices of 2016 to levels around the $9-10/GJ mark. A combination of factors led to prices stabilising around this level. This included government policy for LNG producers to contribute more supply to the domestic market, significant declines in gas consumption for gas power generation and improvements in supply, particularly from Queensland CSG fields and some southern state production areas.

Spot prices then fell from around September 2019. This fall also appears to be driven by several factors. A fall in oil linked international LNG contract prices has reduced LNG export prices, increasing the incentive for LNG proponents to sell gas into the domestic market. New production has come online in the US and Western Australia increasing supply. A significant factor has been the unusually warm winter in the northern hemisphere resulting in a subdued level of demand for LNG across Australia and Europe. It is apparent that some US LNG exporters are currently selling gas at a short run marginal cost that does not recover the cost of liquefaction (Chandra, 2020).

FIGURE 3.1 PRICES IN THE DWGM AND THE SYDNEY, ADELAIDE AND BRISBANE STTMS.

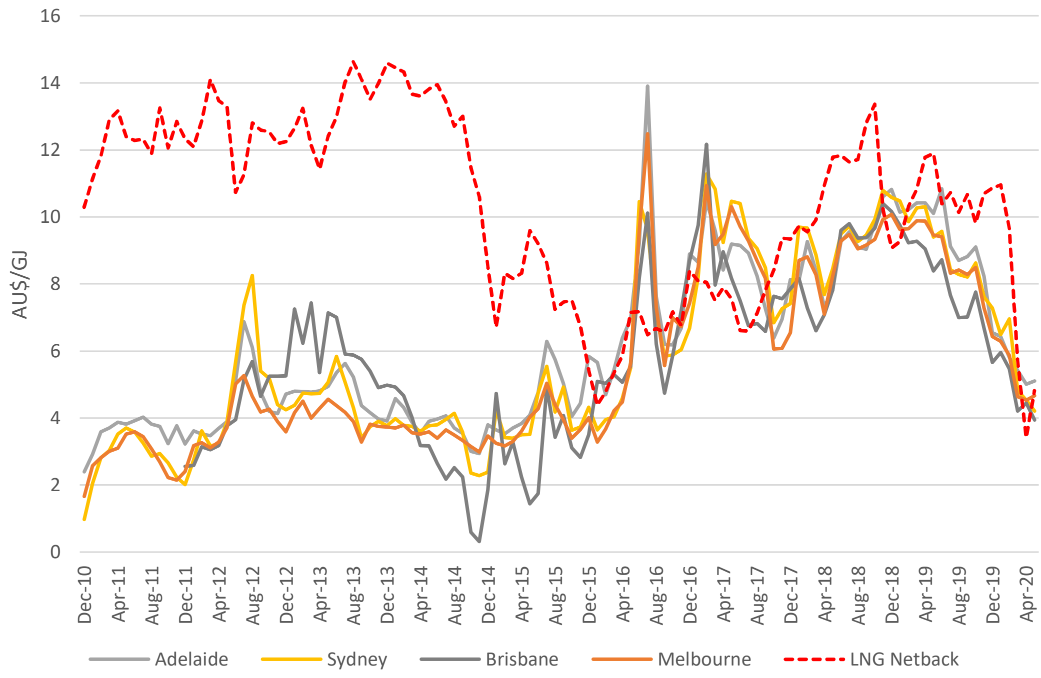


SOURCE: AEMO

There is a link between LNG prices and domestic prices, commonly with reference to a price called the LNG netback price. The ACCC defines an LNG netback price as a measure of an export parity price that a gas supplier could expect to receive for exporting its gas[3]. The link is shown in Figure 3.2. There has been a general correlation between spot prices in the eastern Australian gas market and LNG netback prices since around 2016 when Queensland LNG projects began exporting LNG.

[3] See https://www.accc.gov.au/regulated-infrastructure/energy/gas-inquiry-2017-2025/lng-netback-price-series

FIGURE 3.2 DOMESTIC GAS PRICES COMPARISON WITH ESTIMATED LNG NETBACK



SOURCE: ACIL ALLEN, AEMO AND THE WORLD BANK

3.3 Export and import parity pricing

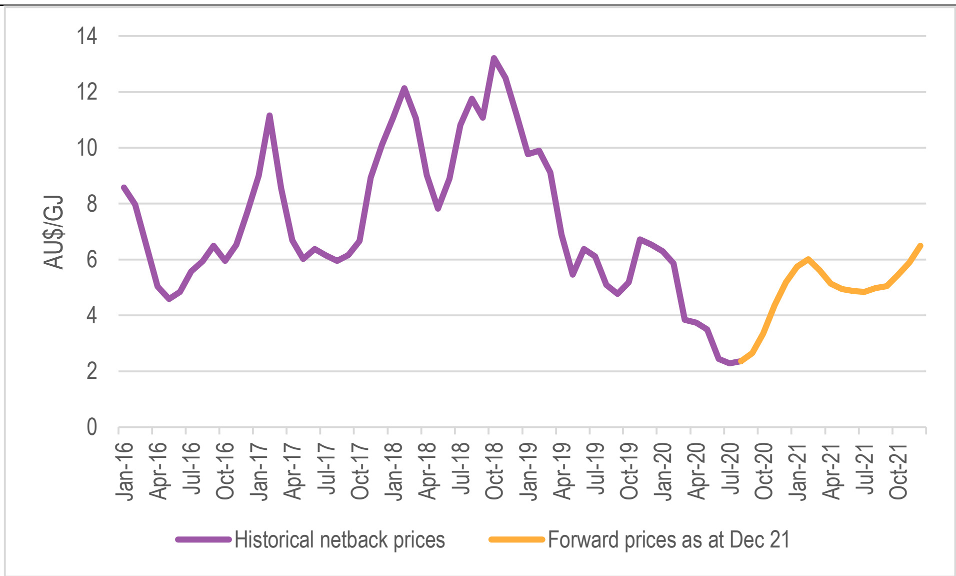
As described above, the emergence of the Gladstone LNG projects has had an effect on gas prices in the eastern Australian domestic market. With the advent of LNG export projects offering a pathway to an international market, prevailing international prices are now influencing domestic gas prices through LNG netback prices.

The ACCC's LNG net back price is based on an export parity price. This is the price that a producer could receive if it shipped its gas to an LNG plant in Gladstone for export. It therefore represents a floor price for producers. Under an export parity price, the floor price for a producer is calculated from the following formula:

$$\begin{aligned} &LNG\ netback\ price\ for\ producer \\ &\qquad = value\ of\ LNG\ at\ the\ outlet\ of\ the\ LNG\ plant \\ &\qquad - cost\ of\ liquefaction \\ &\qquad - cost\ of\ transmission\ from\ the\ producer\ to\ the\ LNG\ plant \end{aligned}$$

The ACCC publishes a time series of historical monthly LNG netback prices at the Wallumbilla Gas Supply Hub and forward monthly LNG netback prices at Wallumbilla. The calculation of the LNG netback price released by the ACCC on 2 July is shown in Figure 3.3.

FIGURE 3.3 ACCC LNG NETBACK PRICES



SOURCE: ACCC - HTTPS://WWW.ACCC.GOV.AU/REGULATED-INFRASTRUCTURE/ENERGY/GAS-INQUIRY-2017-2025/LNG-NETBACK-PRICE-SERIES - ACCESSED ON 2 JULY 2020

The LNG netback futures price estimated as at 2 July, increases over the next 18 months to around AU$6.49 per GJ by December 2021. If the relationship between spot prices and LNG netback price continues as before, it can be expected that domestic spot prices will also increase.

However, when considering the price impact of imports of LNG, it is the import parity price against which domestic producers must compete. Over the long term, import terminals may become necessary for large volumes of supply if domestic exploration and production of onshore deposits in eastern Australia is relatively unsuccessful. If this were to eventuate, the pricing dynamics in the eastern Australian market will increasingly be influenced by LNG import pricing, and away from export parity pricing. The import parity price for LNG supplied to a given location is calculated from the following formula:

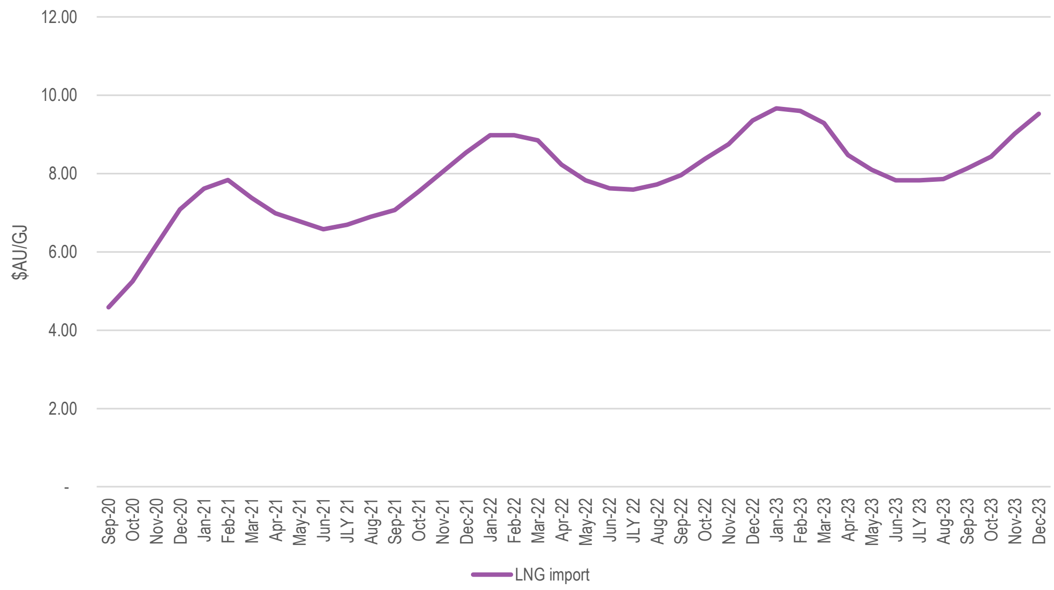
$$
\begin{aligned}
&Import\ parity\ price \\
&\qquad = the\ cost\ of\ LNG\ from\ an\ LNG\ plant + the\ cost\ of\ shipping \\
&\qquad + cost\ of\ regassification
\end{aligned}
$$

Estimates of future import parity prices for LNG at the outlet meter of an import terminal, say at Port Kembla, are shown in Figure 3.4. These are based on futures prices for the Platts JKM marker to 2023 plus shipping and liquefaction costs[4].

The figure shows the import parity price increasing from around AU$4.59 per GJ in September 2020 to between around AU$8/GJ and AU$9 per GJ by the end of 2023. Prices are lower mid calendar year because that time of year corresponds to the northern hemisphere summer when demand for gas is lower.

[4] J KM™ reflects the spot market value of cargoes delivered ex-ship (DES) into Japan, South Korea, China and Taiwan. Deliveries into these locations equate to the majority of global LNG demand.

FIGURE 3.4 IMPORT PARITY PRICE FOR LNG BASED ON JKM FUTURES



Note: Cost of shipping and gasification assumed to be AU$1.20 per GJ

SOURCE: PLATTS JKM MARKER PRICE FOR LNG AS AT 22 JULY 2020

The International Energy Agency expects that natural gas demand will recover from the fall in natural gas demand that occurred in early 2020 (IEA, 2020). It this occurs, US exporters that do not appear to be recovering liquefaction costs might be expected to reverse that policy (Chandra, 2020). This may be a factor influencing price expectations reflected in the futures market.

While longer term projections of future LNG prices are subject to many assumptions, the price trend shown in Figure 3.4 indicates that the delivered LNG import parity price is likely to exceed the cost of Narrabri gas including transmission costs from Narrabri over the longer term. The major benefits from the NGP will occur in the later 2020's and the 2030s as new sources of supply are needed, particularly in the southern states of the eastern Australian gas market.

3.4 Gas contract market

Most eastern Australia is traded via bilateral contracts, or Gas Sales Agreements (GSAs), between gas users and gas producers/retailers. Many GSAs contain non-price terms and conditions that may increase the price of supplying gas to commercial and industrial gas users, particularly under agreements that provide a high degree of flexibility. This could potentially create a premium between LNG netback prices and domestic price offers. Moreover, committing to supply gas over a 12-month (or more) period may create risks for gas suppliers relative to shorter supply periods. However, the details of most GSA's are not publicly available.

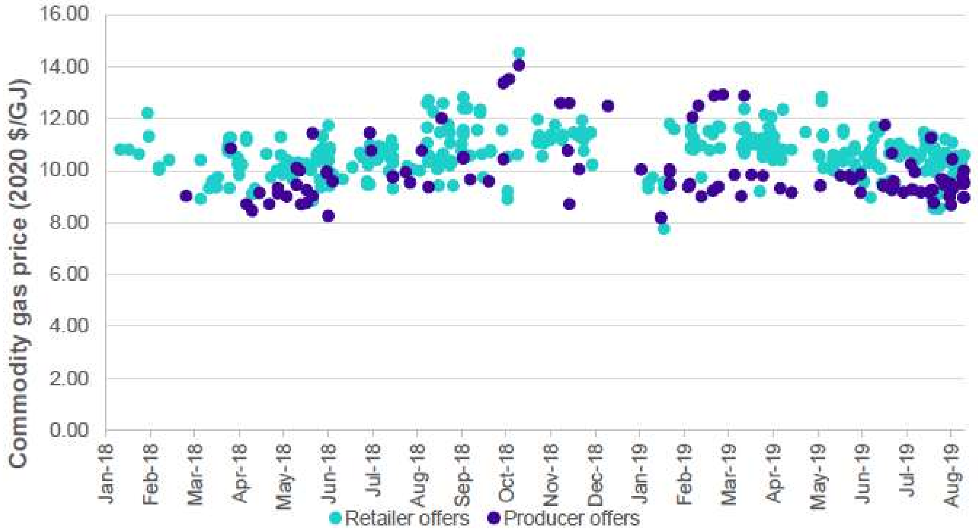
The ACCC, as part of its ongoing inquiry into gas prices in the eastern Australian gas market, monitors offers and bids being made by gas producers and retailers for GSAs.

Figure 3.5 below shows the ACCC data on gas commodity prices included in offers made by producers and retailers for supply in 2020 over the period from 1 January 2018 to 22 August 2019 (ACCC, January 2020). Not all price offers in the chart are for unique combinations of seller and buyer, and some offers may reflect follow-up offers that were made from the same supplier to the same buyer after a previous offer did not result in a GSA.

The figure shows that there was a slight upward trend in prices offered by producers in 2018, with most offers concentrated in the $9–12 per GJ range. Since the start of 2019, the range of prices offered by producers has narrowed, with the majority of producer offers falling between $9 per GJ and

$10 per GJ. While there were a small number of offers above $10 per GJ in 2019, the majority of these had pricing that was linked to Brent crude oil prices. A fall in Brent crude oil futures has resulted in reduced offer prices when compared to similar oil linked offer prices seen in early 2019.

FIGURE 3.5 GAS SUPPLY CONTRACT OFFER PRICES



NOTE: PRICES ARE IN AUD

SOURCE: ACCC JANUARY 2020 GAS INQUIRY REPORT

The ACCC also undertook an analysis of bids and offers to estimate the expected wholesale gas producer and retailer commodity prices in the eastern Australian gas market for 2020. The findings of this analysis are shown in Table 3.1 and Table 3.2.

TABLE 3.1 WHOLESALE GAS COMMODITY PRICES IN GAS SALES CONTRACTS FOR SUPPLY IN 2020

Type of supplier	Avg gas commodity priceAU $/GJ	Commodity price range AU$/GJ
Producer QLD	8.52	8.11 – 9.63
Producers VIC, SA and NSW	9.73	8.86-10.82

SOURCE: (ACCC, JANUARY 2020)

TABLE 3.2 WHOLESALE GAS RETAILER COMMODITY PRICES FOR SUPPLY IN 2020

Type of supplier	Avg gas commodity price AU$/GJ	Commodity price range AU$/GJ
Retailers QLD	10.33	10.00-10.94
Retailers VIC, SA and NSW	10.68	9.19-11.75
Retailer NSW	10.95	9.94-11.75
Retailer SA	10.22	9.19-11.06
Retailer VIC	10.42	9.65-10.79

SOURCE: (ACCC, JANUARY 2020)

Prices in contracts as estimated for 2020 by the ACCC are broadly in the $8.11 per GJ to $11.75 per GJ range.

3.5 Implications for future prices in longer term gas sales agreements

Spot prices are a good indication of possible prices in short term contacts of up to 18 months. They are not a good indication of prices in longer term gas sales contracts. Future prices in GSAs are likely to be driven primarily by:

— the marginal cost of undeveloped, contingent, and prospective resources after around 2026.

— longer term LNG price movements which in turn will be influenced by movements in oil prices, global economic conditions, and global LNG production capacity

— transmission pipeline capacity and the efficiency of the transmission system and capacity trading

— the level of competition in the eastern Australian gas market.

3.5.1 Marginal costs of production

AEMO published its assumptions on the cost of production with its 2020 GSOO. These are based on analysis by the Core Energy Group plus consultations with producers. The costs quoted by AEMO are shown in Table 3.3.

The table shows that the cost of production for 2P undeveloped and 2C contingent resources are higher than 2P developed reserves. Production costs for Queensland undeveloped fields range from $4.48 per GJ to $6.74 per GJ and costs for contingent resources range from $6.45 per GJ to $8.87 per GJ.

Production costs for southern undeveloped fields range from $4.99 per GJ to $5.60 per GJ and costs for contingent resources costs range from $4.07 to $7.54 per GJ. Most of the lower cost fields in the Southern Basins have low remaining undeveloped resources and/or contingent resources.

As the proportion of gas supplied from undeveloped and contingent resources in the southern basins increases, the marginal cost of production can be expected to rise to at least around $5.50 per GJ to $8.32 $ per GJ.

More details of production costs and remaining reserves and resources is provided at Attachment A.

TABLE 3.3 PRODUCTION COSTS (AU$/GJ)

Basin	Project	2P Developed	2P Undeveloped	2C
Queensland				
Galilee	Galilee			8.32
Moranbah	Moranbah	3.16	6.00	7.00
Surat & Bowen	Surat / Bowen / Denison Conventional	2.85	5.95	7.00
Surat & Bowen	QLD CSG - Arrow	3.27	5.63	7.55
Surat & Bowen	QLD CSG - GLNG	3.02	6.60	9.44
Surat & Bowen	QLD CSG - Other	3.81	6.74	8.87
Surat & Bowen	QLD CSG - QCLNG	2.54	4.48	6.45
Cooper Eromanga	Cooper Eromanga	2.44	6.36	7.12
Surat & Bowen	QLD CSG - APLNG	2.25	4.72	7.47
Northern Territory				
Bonaparte	Blacktip	3.13		
Amadeus	Mereenie	3.05		7.54
Southern states				
Bass	Bass	2.90	5.60	6.02

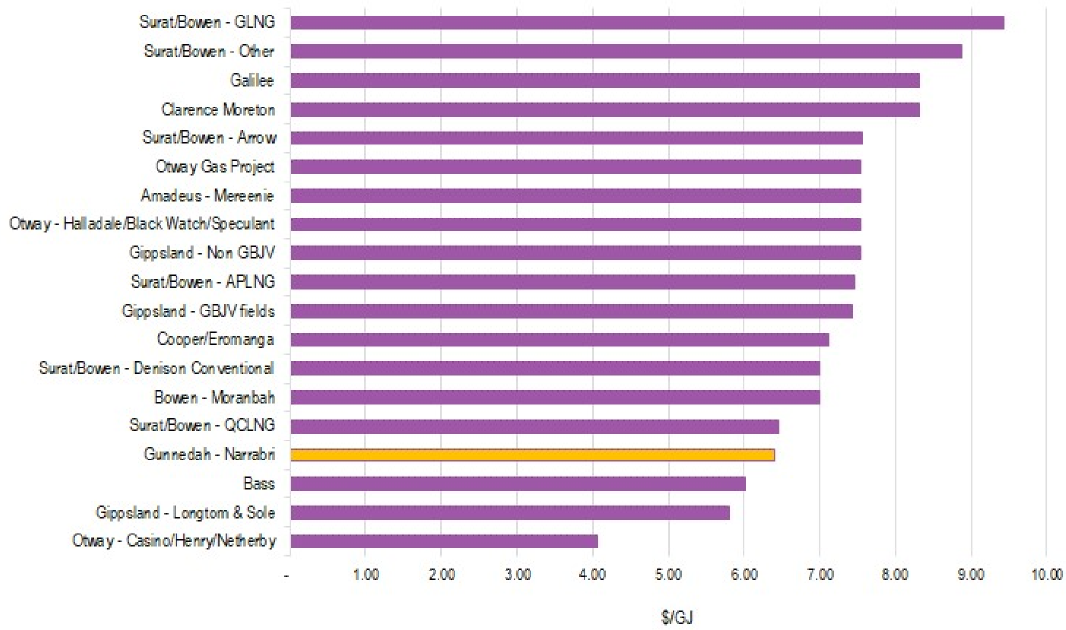
Basin	Project	2P Developed	2P Undeveloped	2C
Sydney	Camden	2.44		
Otway	Casino Henry Netherby	2.34	5.10	4.07
Clarence Moreton	Clarence Moreton			8.32
Gippsland	GBJV & Turrum & Kipper	2.65	5.50	7.43
Gippsland	Gippsland - Non GBJV			7.54
Gunnedah	Gunnedah			6.40
Otway	Halladale/Black Watch/Speculant		4.99	7.54
Gippsland	Longtom & Sole		5.70	5.80
Otway	Otway Gas Project	2.70	5.90	7.54

Note: These data are based on analysis by Core Energy Group and published by AEMO.

SOURCE: (AEMO, FEBRUARY 2020)

The major benefit from the NGP will come over the medium to long term as production from existing fields declines and supply from contingent resources is needed. The costs of supply from future 2C contingent resources is presented in Figure 3.6. After new sources in the Gippsland Basin, the NGP is the cheapest source of supply from 2C contingent resources. Furthermore, with these Bass Strait sources likely to be much smaller sources of supply, the Narrabri project is the cheapest large source of supply, critically important to minimising gas prices during the later years of the 2020s and into the 2030s.

FIGURE 3.6 COST OF 2C CONTINGENT SOURCES OF SUPPLY



Notes:

1 These data are based on analysis by Core Energy Group and published by AEMO.

2 Gas reserves in the Otway Basin and Long Tom and Sole are relatively small – 252 PJ and 216 PJ compared to 1,500PJ for Gunnedah latest estimate.

SOURCE: AEMO, 2020 GAS STATEMENT OF OPPORTUNITIES REPORT

3.6 Efficiency of the transmission system

As indicated earlier, there are policy reviews underway into the efficiency of the gas transmission network. The Energy Council is currently reviewing the regulatory framework applying to gas pipelines.

In March 2019 two market mechanisms were introduced to facilitate the trade of secondary transportation capacity on multiuser transmission pipelines and compression facilities that are providing third party access. These are a Capacity Trading Platform (CTP) that allows shippers to trade secondary capacity and a Day Ahead Auction (DAA) of contracted but unused capacity.

The effectiveness of these instruments is still being assessed by the ACCC but there is evidence that the DAA has been utilised. The effectiveness of the CTP is still being assessed.

Improvements in efficiency of the transmission network will help with more efficient price formation in the market that could be important to meeting peak demand periods in the southern states.

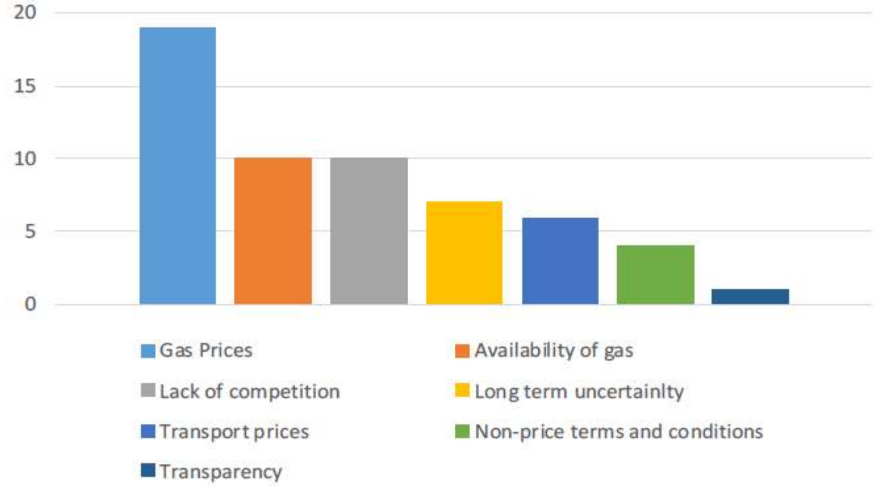
3.7 Level of competition in the eastern Australian gas market

Apart from the efficiency of the gas transmission network, the overall level of competition in the gas market also has an influence on price levels. There is some evidence that the market is not as competitive as it could be, with some producers shadow pricing against future expected LNG netback prices. Increasing the number of domestic producers would assist in increasing the level of competition in the market.

3.8 Comment

The eastern Australian gas market is undergoing fundamental adjustments that is creating volatility in short term spot prices and raising concerns amongst commercial and industrial consumers over the ability to find longer term contracts that meet their needs. From their point of view, the availability of suitable gas contracts is important to their business and to the NSW economy. In the ACCC’s latest interim report, the ability to source supply (particularly on long term contracts) and the current lack of competition in the gas market rank equal second to price as the most important requirements for commercial and industrial customers in the current market (Figure 3.7.)

FIGURE 3.7 GAS MARKET ISSUES FOR C&I USERS



Note: Y-axis represents number of participants that ranked each concern in their top three.

SOURCE: ACCC JANUARY 2020 GAS INQUIRY INTERIM REPORT

The need to bring on stream more undeveloped and contingent resources will result in increasing marginal costs of production from fields in both the north and south of the eastern Australian gas market. This will place an upward pressure on future prices.

The LNG netback price will continue to be an important factor influence in future price paths for gas in the southern states. However, import parity prices will also be important for price formation in the southern states of the eastern Australian gas market. With a possible outlook of oil prices in the longer term between US$40 per bbl to US$80 per barrel and a rebalancing of the Asian LNG market, LNG contract prices could be expected to rise to between A$8 per GJ to A$12 per GJ over the longer term.

The efficiency of the gas transmission system and the competitiveness of the market will also be important to ensuring that gas consumers, and industrial consumers in NSW, will be able to contract for gas at competitive prices. Increasing the availability of new domestic supplies in the southern states is critical for the future security of supplies to industrial consumers.

The NGP lies within the range of costs that would deliver a secure supply of domestic gas to both small and large industrial consumers. There are also proposals to develop LNG import facilities in NSW and Victoria. The two approaches are not necessarily mutually exclusive depending on the price tolerance of consumers and their relative costs. However, it is important to recognise that domestic supplies and imported supplies exhibit different service offerings.

Existing commercial and industrial consumers have already expressed an interest in contracting gas from the NGP because of the certainty of supply and price that they need to implement their longer-term business strategies. According to the ACCC, some commercial and industrial consumers have expressed concern over sourcing gas from LNG import proponents as their loads do not satisfy minimum purchase requirements.

The ACCC further commented:

“A number of large C&I users have signed MOU’s with LNG import terminal proponents. However, these large C&I users have indicated discussions about long term supply arrangements are inflexible, with proponents offering little take or pay flexibility and high oil linked prices. Two gas users noted that there is limited ability to take advantage of spot cargo buying in the short term given facility scheduling.

Previously, users generally characterised the entry of new suppliers and new supply in the market as beneficial. However, as import terminals become more likely with the AIE (Port Kembla) project attaining planning approval, some C&I users have raised concerns about the potential impact of LNG terminals on domestic gas prices.”

The ACCC further noted the comments from one commercial and industrial user as follows:

“LNG import terminals will permanently introduce an LNG import-parity and local processing cost price reference for the domestic market. This is at least $1.50 - $2/GJ higher than LNG export parity on a netback basis, in our assessment.”

The role of domestic suppliers and import terminals in supplying the market is therefore somewhat different and may address different segments of the market. For example, import terminals could be effective in supplying gas to meet peak demand periods and acting as small storage facilities and their development set-up allows them to provide this flexible rate of supply. ACIL Allen is of the view that this is likely to be the major benefit of import terminals initially, and this is shared by AEMO. Over time, they are more likely to be needed broadly across the market for supply as large mature sources of supply diminish (e.g. Gippsland basin). However, domestic projects like the Narrabri are more likely to be targeted at providing regular long-term supply to commercial and industrial loads.

The Narrabri project will also be dedicated to the domestic market and will increase competition in supply of gas to that market.

4 IMPACT OF THE NARRABRI GAS PROJECT ON NSW GAS PRICES

The following section describes the findings of gas market modelling of the likely impact of the NGP on gas prices in NSW. ACIL Allen used its GasMark model of the eastern Australian gas market to model the prices in Sydney that would occur with and without the Narrabri Gas project. The modelling shows that the NGP has the potential to reduce prices in Sydney in a scenario that includes LNG import terminals at Port Kembla and Crib Point. The modelling also shows that the project has the ability to place downward pressure on prices because it adds another source of supply close to the Sydney market at a time when additional contingent gas supplies are needed to meet market demand in the eastern Australian gas market.

4.1 Introduction

As discussed previously the factors that will affect gas prices include consumers' price tolerances, producers' marginal costs of production and the optimal operation of the gas transportation network.

Most of the gas traded in the east Australian gas market is under long term gas sales agreements. It is difficult to model the impact of contracts on average prices of gas at different points in the market as the terms and prices contained in these gas sales agreements are not public.

In a pure spot market, the optimal price at any time at a given location is one that maximises the consumer and producer surplus taking into account the optimal use of the gas transmission network[5]. When an additional source of supply is introduced into the gas transmission network, it allows the reallocation of gas molecules to other loads. For example, if gas from the NGP is economic to serve the Sydney market, it means that less gas is required to be transmitted to Sydney from Victorian fields or from South Australian and Queensland fields.

4.2 Impact of NGP on prices in Sydney

Gas prices in Sydney are a general indicator of gas prices in NSW. ACIL Allen has therefore modelled gas prices in Sydney under different scenarios to assess the impact of the NGP on gas prices in NSW.

ACIL Allen's GasMark model is based on an assumption that the east coast gas market operates as a single pool market, connecting supply sources with customer loads through the interconnected network of transmission pipelines. It is a theoretical model that projects where gas prices would head under pure market conditions. It does not take into account the impact of gas contracts on delivered prices year on year. Nevertheless, it indicates the price paths that would influence contract prices as they are renegotiated over time. A more detailed description of GasMark is provided in Attachment B.

[5] As discussed in section 0

The model has been run with and without the Narrabri project. The base case includes LNG import terminals at Port Kembla and at Crib Point in Victoria. The demand profiles are consistent with AEMO's 2020 GSOO and production costs are based on ACIL Allen's internal data which is aligned with production costs assumed for the GSOO.

The assumptions on which the base case was constructed are set out below.

- Oil price at US$60/barrel
- LNG export price at AU$10.90 per GJ
- Two LNG import terminals online – Crib Point (AGL) and Port Kembla (AIE)
- Pipeline capacities are unchanged from current nameplate capacities
- Narrabri online by 2024 and maximum annual production capacity of 75 PJ per annum
- Narrabri production cost - $6.40/GJ
- Pipeline tariff - $1.50/GJ

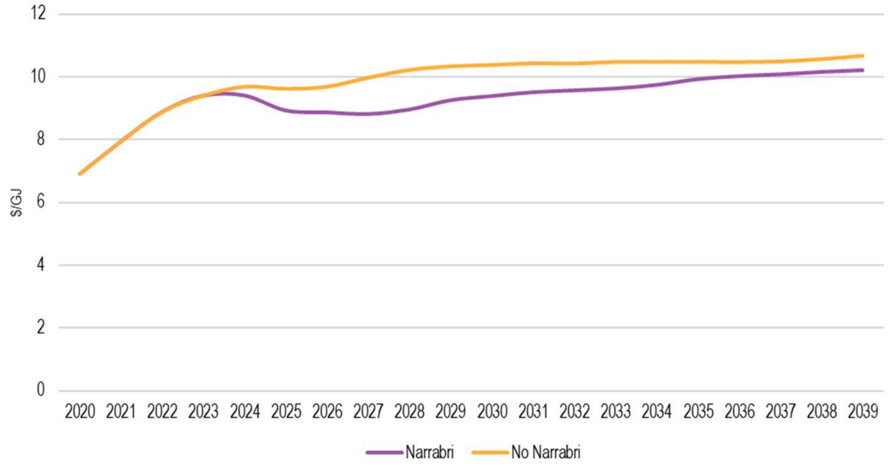
The modelling shows that gas prices in Sydney would be between around 4 per cent and 12 percent lower from 2025 onwards over the 25-year evaluation period with the Narrabri project than without it. The main benefit for prices is through the late 2020s and early 2030s when Narrabri reaches full production and as the market progressively moves towards higher volumes of 2C contingent resources.

The proximity of the Narrabri project to major customers in Sydney means it can also compete with many undeveloped 2P projects on economics alone. According to marginal production cost estimates in the 2020 GSOO report by AEMO, the average undeveloped 2P marginal cost of production is $5.66/GJ. Cheaper sources of undeveloped 2P can still be extracted from the Bass Strait but the majority of this is likely to satisfy Victorian demand in the first instance. Some supply will then also be made available to NSW customers via the Eastern Gas Pipeline and NSW-Victoria Interconnector.

However, New South Wales has also been increasingly reliant on supply from Queensland CSG over the past few years. The marginal cost for undeveloped 2P CSG reserves in Queensland is now estimated to be around $5.70/GJ. With transportation costs of around $2.50/GJ added on according to the latest tariffs posted by APA, the delivered cost will be north of $8/GJ. It is expected that the Narrabri project will be competitive with these prices considering the ability of Santos to reduce costs of production to $6.40/GJ. This development means the impact from Narrabri on the market is that it will increase competition in the eastern Australian gas market by providing gas consumers with another competitive source of supply. This is a key point in placing downward pressure on gas prices.

The results are shown in Figure 4.1.

FIGURE 4.1 PROJECTED WHOLESALE (SPOT) PRICE IN SYDNEY WITH AND WITHOUT THE NGP



SOURCE: ACIL ALLEN GASMARK MODELLING

4.3 Impact of Fertiliser plant in Narrabri

Santos has indicated that it is in discussion with a party that is considering establishing a fertiliser plant in Narrabri if the NGP proceeds. The plant would draw 40 TJ per day of gas from the project or about 20 per cent of the projects output.

ACIL Allen re-ran GasMark for the base case but adding the impact of the fertiliser plant as a new load in the network.

With the fertiliser plant included, the modelling showed that the impact on wholesale (spot) gas prices in Sydney would be slightly less than it would have been without the fertiliser plant in Narrabri; around 3 per cent to 9 per cent lower than without the NGP from 2025 onwards over the 25 year evaluation period.

These results are robust for higher and lower assumptions for LNG and gas consumption levels.

4.4 Comment

The model results are based on the behaviour of the market as a pure spot market. However, the results give an indication of the forces that would drive prices in long term contracts over time. It is not so much that the modelled prices are lower but that the project has the ability to place downward pressure on prices because it adds another source of supply close to the Sydney market at a time when additional contingent gas supplies are needed to meet market demand in the eastern Australian gas market. This increased competition is important to maintaining downward pressure on prices.

A key non-price factor that is important to reiterate in this assessment is security of supply and long-term availability of supply. This is especially key for commercial and industrial customers who are the target customer group of Narrabri supply. The Narrabri project is likely to be in the position to offer large volumes of gas on long term contracts. This has been difficult in recent times due to the tightness in supply and the relatively little competition in the upstream sector. With the commitment made by Santos to make all the gas produced from the Narrabri project available for the domestic market, a new competitive source of supply close to Sydney contributing around 75 PJ per annum is expected to lead to more competitive prices on long term gas contracts, particularly as the market moves into the late 2020s and 2030s.

5

BENEFIT COST ANALYSIS

This Chapter outlines the updated benefit cost analysis. The lower capital costs increase the net present value of the base case and all the scenarios tested as part of the sensitivity analysis. The lower capital costs also show that the project has a positive net present value for all cases.

5.1 Introduction

The benefit cost analysis has been updated for reduction in the estimate of capital costs based on experience with the cost of well completions in Queensland and South Australia. The updates of capital costs are consistent with reductions in the onshore business of Santos taking into account

— 40 per cent reduction in the drilling costs in the Cooper Basin

40 per cent reduction in connection costs for GLNG

— 10 per cent reduction in the cost of associated facilities for GLNG

The maximum production capacity of the NGP remains at 200 TJ per day with 2C reserves of approximately 1,500 PJ.

The NPV calculations in the original spreadsheets for the 6 scenarios tested in the original EIS were revised using these latest capital cost estimates. The calculations were brought forward to $2021-22 to be consistent with the new commissioning date.

No other data or methodology was changed. ACIL Allen considers that the estimates for NSW are conservative.

The following sections present the revised results.

5.2 Base case

The revised table for the project is provided in Table 5.1. The revised NPV compared to the original NPV is as follows:

— $1,985 million compared to $1,535 million for the self-generated electricity option

— $2,088 million compared to $1,639 million for the grid supplied electricity option

The revised benefit cost ratios for project compared to the original benefit cost ratios are as follows:

— 1.58 compared to 1.39 for the self-generated option

— 1.62 compared to 1.43 for the grid-supplied option

TABLE 5.1 BCA RESULTS FOR THE BASE CASE

Category of cost/benefit ($2021/22 million) (discounted at 7% discount rate)	Electricity Option 1 (Self-generated)	Electricity Option 2 (Grid supplied)
Costs		
Capital costs	1,555.4	1,555.4
Operating costs	1,578.0	1,578.0
Foregone agricultural production	3.1	3.1
Noise and vibration costs	1.7	1.7
Biodiversity offsets	43.5	43.5
Social cost of carbon	267.5	164.0
Residual value (land and infrastructure)	0.0	0.0
Total project costs	**3,449.2**	**3,345.7**
Benefits		
Project revenue	5,403.4	5,403.4
Additional agricultural output (amended water)	0.8	0.8
Compensation to landholders	29.7	29.7
Total project benefits	**5,433.9**	**5,433.9**
Project net present value	**1,984.7**	**2,088.2**
Project benefit-cost ratio	**1.58**	**1.62**
Additional measures		
Australian net present value	**1,832.6**	**1,936.1**
Australian benefit-cost ratio	**1.60**	**1.66**
NSW net present value	**901.8**	**934.9**
NSW benefit-cost ratio	**1.92**	**1.99**
Existing assumptions		
Domestic ownership ratio	87%	87%
NSW proportion	32%	32%

Note: The only change to the tables included in the EIS is to the capital costs. All cell logic is unchanged.

SOURCE: (BAECONOMICS, 5 OCTOBER 2018) AND ACIL ALLEN CONSULTING

5.3 Sensitivity test – different discount rate assumptions

The revised table for the different discount rate assumptions is provided in Table 5.2 The revised NPV for the project compared to the original NPV is as follows:

— $3,333 million compared to $2,785 million for the self-generated electricity option discounted at 4 per cent

— $3,485 million compared to $2,938 million for the grid supplied electricity option discounted at 4 per cent

— $1,151 million compared to $ 773 million for the self-generated electricity option discounted at 10 per cent

— $1,223.7 million compared to $846 million for the grid supplied electricity option discounted at 10 per cent

TABLE 5.2 BCA RESULTS WITH DIFFERENT DISCOUNT RATES

Category of cost/benefit ($2021/2022 million) (discounted at 7% discount rate)	Electricity Option 1 (Self-generated)		Electricity Option 2 (Grid supplied)	
	at 4% discount rate	at 10% discount rate	at 4% discount rate	at 10% discount rate
Costs				
Capital costs	1,786.0	1,379.9	1,786.0	1,379.9
Operating costs	2,229.7	1,161.5	2,229.7	1,161.5
Foregone agricultural production	4.1	2.4	4.1	2.4
Noise and vibration costs	2.4	1.2	2.4	1.2
Biodiversity offsets	44.7	42.3	44.7	42.3
Social cost of carbon	377.4	198.7	225.1	125.6
Residual value (land and infrastructure)	0.0	0.0	0.0	0.0
Total project costs	**4,444.2**	**2,786.0**	**4,291.9**	**2,712.9**
Benefits				
Project revenue	7,733.9	3,914.0	7,733.9	3,914.0
Additional agricultural output (amended water)	1.1	0.6	1.1	0.6
Compensation to landholders	42.1	22.0	42.1	22.0
Total project benefits	**7,777.1**	**3,936.7**	**7,777.1**	**3,936.6**
Project net present value	**3,332.9**	**1,150.6**	**3,485.2**	**1,223.7**
Project benefit-cost ratio	**1.75**	**1.41**	**1.81**	**1.45**
Additional measures				
Australian net present value	2,899.6	1,001.1	3,032.2	1,064.6
Australian benefit-cost ratio	1.65	1.36	1.71	1.39
NSW net present value	927.9	320.3	970.3	340.7
NSW benefit-cost ratio	1.21	1.11	1.23	1.13
Existing assumptions				
Domestic ownership ratio	87%	87%	87%	87%
NSW proportion	32%	32%	32%	32%

Note: The only change to the tables included in the EIS is to the capital costs. All cell logic is unchanged.

SOURCE: (BAECONOMICS, 5 OCTOBER 2018) AND ACIL ALLEN CONSULTING

5.4 Sensitivity test - 10 per cent reduction in production

The revised table for the a 10 per cent reduction in production is provided in Table 5.3' The revised NPV for the project compared to the original NPV is as follows:

— $1,444 million compared to $996 million for the self-generated electricity option for a 10 per cent reduction in gas production

— $1,548 million compared to $1,099 million for the grid supplied electricity option for a 10 per cent reduction in gas production

TABLE 5.3 BCA RESULTS FOR A 10 PER CENT REDUCTION IN GAS PRODUCTION

Category of cost/benefit ($2021/22 million) (discounted at 7% discount rate), 10 % reduction in gas production estimates across all years	Electricity Option 1 (Self-generated)	Electricity Option 2 (Grid supplied)
Costs		
Capital costs	1,555.4	1,555.4
Operating costs	1,578.0	1,578.0
Foregone agricultural production	3.1	3.1
Noise and vibration costs	1.7	1.7
Biodiversity offsets	43.5	43.5
Social cost of carbon	267.5	164.0
Residual value (land and infrastructure)	0.0	0.0
Total project costs	**3,449.2**	**3,345.7**
Benefits		
Project revenue	4,863.1	4,863.1
Additional agricultural output (amended water)	0.8	0.8
Compensation to landholders	29.7	29.7
Total project benefits	**4,893.6**	**4,893.6**
Project net present value	**1,444.4**	**1,547.9**
Project benefit-cost ratio	**1.42**	**1.46**
Additional measures		
Australian net present value	1,256.7	1,346.7
Australian benefit-cost ratio	1.36	1.40
NSW net present value	402.1	430.9
NSW benefit-cost ratio	1.12	1.13
Existing assumptions		
Domestic ownership ratio	87%	87%
NSW proportion	32%	32%

Note: The only change to the tables included in the EIS is to the capital costs. All cell logic is unchanged.

SOURCE: (BAECONOMICS, 5 OCTOBER 2018) AND ACIL ALLEN CONSULTING

5.5 Sensitivity test – 10 per cent, 20 per cent and 30 per cent reduction in gas price estimates for electricity option 1

The revised table for the different gas price reductions is provided in Table 5.4. The revised NPV for the project compared to the original NPV is as follows:

— $1444 million compared to $1,000 million for a 10 per cent reduction in gas price for a 10 per cent reduction on gas prices

— $904 million compared to $455 million for a 20 per cent reduction in gas price for a 20 per cent reduction in gas prices

— $364 million compared to negative $ 83 million for a 30 per cent reduction in gas price for a 30 per cent reduction in gas prices

TABLE 5.4 BCA RESULTS FOR REDUCTIONS IN GAS PRICES – SELF GENERATED OPTION

Category of cost/benefit ($2021/22 million) (discounted at 7% discount rate)	Electricity Option 1 (Self-generated)		
	10 % reduction in the real gas price across all years	20 % reduction in the real gas price across all years	30 % reduction in the real gas price across all years
Costs			
Capital costs	1,555.4	1,555.4	1,555.4
Operating costs	1,578.0	1,578.0	1,578.0
Foregone agricultural production	3.1	3.1	3.1
Noise and vibration costs	1.7	1.7	1.7
Biodiversity offsets	43.5	43.5	43.5
Social cost of carbon	267.5	267.5	267.5
Residual value (land and infrastructure)	0.0	0.0	0.0
Total project costs	**3,449.2**	**3,449.2**	**3,449.2**
Benefits			
Project revenue	4,863.1	4,322.7	3,782.4
Additional agricultural output (amended water)	0.8	0.8	0.8
Compensation to landholders	29.7	29.7	29.7
Total project benefits	**4,893.6**	**4,353.2**	**3,812.9**
Project net present value	**1,444.4**	**904.0**	**363.7**
Project benefit-cost ratio	**1.42**	**1.26**	**1.11**
Additional measures			
Australian net present value	1,256.7	786.5	316.4
Australian benefit-cost ratio	1.36	1.23	1.09
NSW net present value	402.1	251.7	101.3
NSW benefit-cost ratio	1.12	1.07	1.03
Existing assumptions			
Domestic ownership ratio	87%	87%	87%
NSW proportion	32%	32%	32%

Note: The only change to the tables included in the EIS is to the capital costs. All cell logic is unchanged.

SOURCE: (BAECONOMICS, 5 OCTOBER 2018) AND ACIL ALLEN CONSULTING

5.6 Sensitivity test – 10 per cent, 20 per cent and 30 per cent reduction in gas price estimates for electricity option 2

The revised table for the different gas price assumptions is provided in Table 5.4. The revised NPV for the project compared to the original NPV is as follows:

— $1548 million compared to $1098 million for a 10 per cent reduction in gas price for a 10 per cent reduction on gas prices

— $1008 million compared to $559 million for a 20 per cent reduction in gas price for a 20 per cent reduction in gas prices

— $467 million compared to negative $ 18 million for a 30 per cent reduction in gas price for a 30 per cent reduction in gas prices

TABLE 5.5 BCA RESULTS FOR REDUCTIONS IN GAS PRICES – GRID SUPPLIED OPTION

Category of cost/benefit ($2021/22 million) (discounted at 7% discount rate)	Electricity Option 2 (Grid supplied)		
	10 % reduction in the real gas price across all years	20 % reduction in the real gas price across all years	30 % reduction in the real gas price across all years
Costs			
Capital costs	1,555.4	1,555.4	1,555.4
Operating costs	1,578.0	1,578.0	1,578.0
Foregone agricultural production	3.1	3.1	3.1
Noise and vibration costs	1.7	1.7	1.7
Biodiversity offsets	43.5	43.5	43.5
Social cost of carbon	164.0	164.0	164.0
Residual value (land and infrastructure)	0.0	0.0	0.0
Total project costs	**3,345.7**	**3,345.7**	**3,345.7**
Benefits			
Project revenue	4,863.1	4,322.7	3,782.4
Additional agricultural output (amended water)	0.8	0.8	0.8
Compensation to landholders	29.7	29.7	29.7
Total project benefits	**4,893.5**	**4,353.2**	**3,812.9**
Project net present value	**1,547.8**	**1,007.5**	**467.2**
Project benefit-cost ratio	**1.46**	**1.30**	**1.14**
Additional measures			
Australian net present value	1,346.6	876.5	406.5
Australian benefit-cost ratio	1.40	1.26	1.12
NSW net present value	430.9	280.5	130.1
NSW benefit-cost ratio	1.13	1.08	1.04
Existing assumptions			
Domestic ownership ratio	87%	87%	87%
NSW proportion	32%	32%	32%

Note: The only change to the tables included in the EIS is to the capital costs. All cell logic is unchanged.

SOURCE: (BAECONOMICS, 5 OCTOBER 2018) AND ACIL ALLEN CONSULTING

5.7 Sensitivity test – 10 per cent reduction in gas prices and 10 per cent reduction in production

The revised table for a 10 per cent reduction in gas prices and a 10 per cent reduction in production is provided in Table 5.4. The revised NPV for the project compared to the original NPV is as follows:

— $958 million compared to $509 million for a 10 per cent reduction in both production and gas price for option 1

— $1062 million compared to $613 million for a 10 per cent reduction in both production and gas price for option 2

TABLE 5.6 BCA RESULTS FOR A 10 PER CENT REDUCTION IN GAS PRICES AND PRODUCTION

Category of cost/benefit ($2021/22 million) (discounted at 7% discount rate), 10 % reduction in gas production and gas price estimates across all years	Electricity Option 1 (Self-generated)	Electricity Option 2 (Grid supplied)
Costs		
Capital costs	1,555.4	1,555.4
Operating costs	1,578.0	1,578.0
Foregone agricultural production	3.1	3.1
Noise and vibration costs	1.7	1.7
Biodiversity offsets	43.5	43.5
Social cost of carbon	267.5	164.0
Residual value (land and infrastructure)	0.0	0.0
Total project costs	**3,449.2**	**3,345.7**
Benefits		
Project revenue	4,376.8	4,376.8
Additional agricultural output (amended water)	0.8	0.8
Compensation to landholders	29.7	29.7
Total project benefits	**4,407.3**	**4,407.2**
Project net present value	**958.1**	**1,061.6**
Project benefit-cost ratio	**1.28**	**1.32**
Additional measures		
Australian net present value	833.6	923.6
Australian benefit-cost ratio	1.24	1.28
NSW net present value	266.7	295.5
NSW benefit-cost ratio	1.08	1.09
Existing assumptions		
Domestic ownership ratio	87%	87%
NSW proportion	32%	32%

Note: The only change to the tables included in the EIS is to the capital costs. All cell logic is unchanged.
SOURCE: (BAECONOMICS, 5 OCTOBER 2018) AND ACIL ALLEN CONSULTING

5.8 Sensitivity test – 10 per cent increase in capital and operating costs

The revised table for a 10 per cent increase in capital and operating costs is provided in Table 5.1. The revised NPV for the project compared to the original NPV is as follows:

— $1,674 million compared to $787 million for the self-generated electricity option

— $1778 million compared to $890 million for the grid supplied electricity option

TABLE 5.7 BCA RESULTS FOR A 10 PER CENT INCREASE IN CAPITAL AND OPERATING COSTS

Category of cost/benefit ($2021/22 million) (discounted at 7% discount rate), 10 % increase in CAPEX and OPEX estimates across all years	Electricity Option 1 (Self-generated)	Electricity Option 2 (Grid supplied)
Costs		
Capital costs	1,710.9	1,710.9
Operating costs	1,735.8	1,735.8
Foregone agricultural production	3.1	3.1
Noise and vibration costs	1.7	1.7
Biodiversity offsets	43.5	43.5
Social cost of carbon	267.5	164.0
Residual value (land and infrastructure)	0.0	0.0
Total project costs	**3,762.5**	**3,659.0**
Benefits		
Project revenue	5,403.4	5,403.4
Additional agricultural output (amended water)	0.8	0.8
Compensation to landholders	32.7	32.7
Total project benefits	**5,436.9**	**5,436.9**
Project net present value	**1,674.4**	**1,777.9**
Project benefit-cost ratio	**1.45**	**1.49**
Additional measures		
Australian net present value	1,674.4	1,777.9
Australian benefit-cost ratio	1.45	1.49
NSW net present value	718.5	751.6
NSW benefit-cost ratio	1.68	1.73
Existing assumptions		
Domestic ownership ratio	87%	87%
NSW proportion	32%	32%

Note: The only change to the tables included in the EIS is to the capital costs. All cell logic is unchanged.

SOURCE: (BAECONOMICS, 5 OCTOBER 2018) AND ACIL ALLEN CONSULTING

5.9 Comment

The NPV results are all increased with the lower capital costs compared with the NPVs calculated in the original EIS as would be expected. However, all sensitivity tests showed positive NPVs which was not the case with the earlier CBA.

6 MACROECONOMIC AND REGIONAL ANALYSIS

This chapter reports on the macroeconomic and regional analysis with the revised capital costs. The modelling is done with ACIL Tasman's Computable General Equilibrium model using the same assumptions with one exception. The original assumption that employment growth is constrained nationally is relaxed reflecting the current economic outlook for employment. The results show an overall increase in contribution to the Moree - Narrabri region as well as the rest of NSW.

6.1 Revised assumptions

The original macroeconomic and regional analysis was conducted using Tasman Global, ACIL Allen's Computable General Equilibrium (CGE) model. Two important assumptions were made when this modelling commenced. The first was that the overall employment for Australia was constrained. The second was that the project would have no impact on gas prices as it was assumed that it would substitute for other gas supplies that were available at the time.

The employment constraint was applied based on the economic conditions at the time that were still influenced by the impact of the mining boom. This constraint is no longer appropriate given the economic outlook post COVID. Accordingly, ACIL Allen's standard Tasman Global model allows a more relaxed employment constraint and we have adopted this for this updated modelling.

We have not changed the assumption about the impact of the project on gas prices. As discussed in chapter 3, the project can be expected to have an impact on gas prices. However, we have not changed this assumption. The effect of this latter assumption is to underestimate the benefits to other sectors of the economy of lower gas prices. Therefore, the results reported below are conservative.

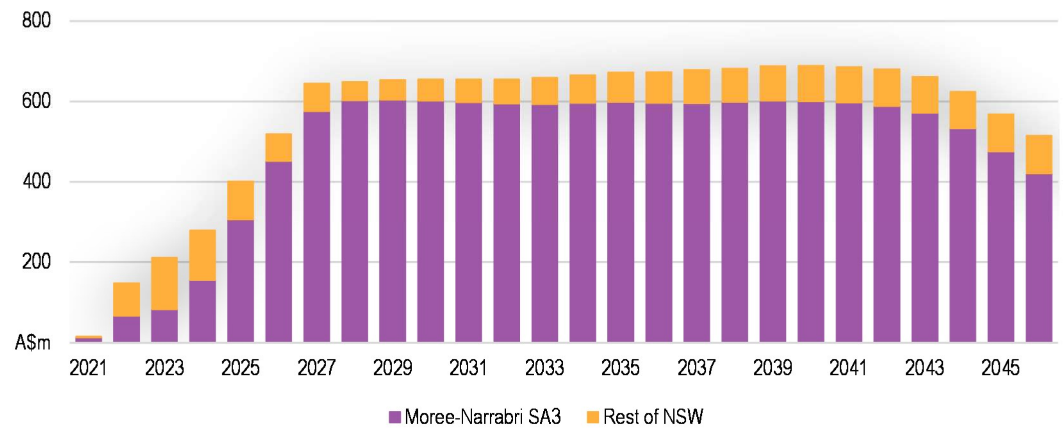
6.2 Impact on real economic output

Real economic output or the contribution to the Gross Regional Product of the Moree-Narrabri SA3 region and the Gross State Product of New South Wales (excluding the Moree-Narrabri SA3 region) is presented in Figure 6.1 and Table 6.1. During the construction phase, the bulk of the impact is realised in the rest of New South Wales. This is because a large amount of goods and services will have to be sourced from outside the SA3 region to construct the Project thereby creating economic benefits to those areas. In the operations phase, more of the goods and services will be sourced from within the region. In addition, the value of production from the Project is attributed to the SA3 region.

In comparison to the operations phase (which begins in 2020), the projected changes in real economic output from the initial investment phase are relatively small. This is because the largest changes in real economic output are projected to occur broadly in line with the value of production.

More specifically, it is the operations phase where the key benefits of the Project are expected to be realised through the monetisation of otherwise unutilised resources and additional factors of production. In contrast, the construction phase is largely increasing demand for scarce factors of production and so has a smaller effect on economic output compared to the size of the investment.

FIGURE 6.1 REAL ECONOMIC OUTPUT: NARRABRI GAS PROJECT ($2021)



SOURCE: ACIL ALLEN

Over the period 2021 to 2046, the Narrabri Gas Project is projected to increase the real economic output of:

— Gross Regional Product of the Moree-Narrabri SA3 region is estimated to be higher by just over $12.6 billion relative to the Base Case (with a net present value of $5.3 billion, using a 7 per cent real discount rate.
  – an increase of 14 per cent and 16 per cent respectively than the respective figures in the supplementary report prepared by ACIL Allen in September 2018.
— Gross State Product of New South Wales by $14.7 billion relative to the Base Case (with a net present value of $6.2 billion, using a 7 per cent real discount rate).
  – an increase of 23 per cent higher and 22 per cent respectively than in the supplementary report.

TABLE 6.1 PROJECTED CUMULATIVE CHANGE IN REAL ECONOMIC OUTPUT AND REAL INCOME IN EACH REGION AS A RESULT OF THE NARRABRI GAS PROJECT RELATIVE TO THE BASE CASE ($2016)

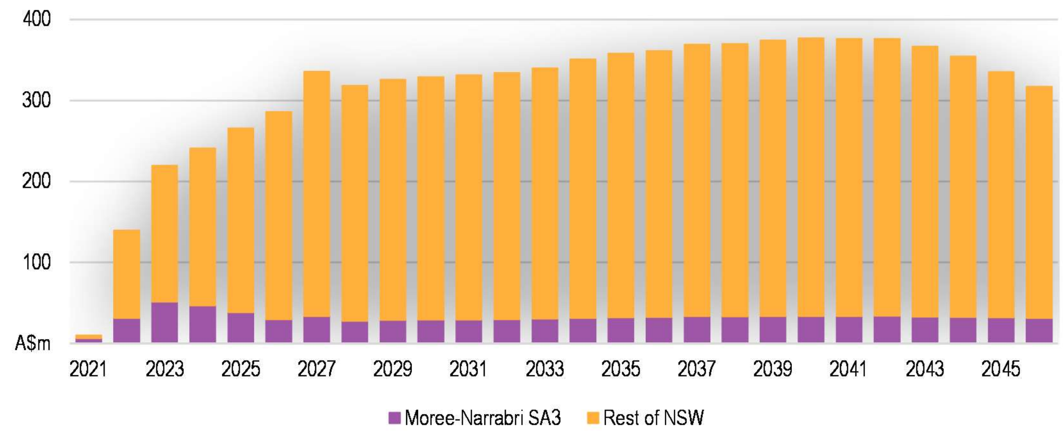
	Real economic output			Real income		
	Total (2021 to 2046)	Net present value* 4%	7%	Total (2021 to 2062)	Net present value* 4%	7%
	2016 A$m	2016 A$m	2016 A$m	2016 A$m	2016 A$m	2016 A$m
Moree-Narrabri SA3 region	12,610	7,430	5,253	833	531	403
Rest of NSW	2,019	1,260	946	7,331	4’119	3,154
Total NSW	**14,628**	**8,690**	**6,199**	**8,164**	**4,908**	**3,548**

*SOURCE: ACIL ALLEN. NOTE: * THE USE OF THE 4 PER CENT AND 7 PERCENT ARE CONSISTENT WITH NSW GOVERNMENT GUIDELINES*

6.3 Impact on real incomes

The contribution of the Narrabri Gas Project to the real incomes of people living in the Moree-Narrabri SA3 region and the rest of New South Wales is presented in Figure 6.2 and Table 6.1

FIGURE 6.2 REAL INCOMES: NARRABRI GAS PROJECT ($2016)



SOURCE: ACIL ALLEN

Over the period 2021 to 2046, the Narrabri Gas Project is projected to increase real incomes raising the ability of residents to consume goods and services and to accumulate wealth in the form of financial and other assets. This includes an increase in the real incomes of:

— residents of the Moree-Narrabri region by a cumulative total of $833 billion, relative to the base case (with a net present value of $403 million, using a 7 per cent real discount rate).
  – an increase of 38 per cent and 31 per cent respectively over findings of the supplementary report.
— residents of New South Wales by $8.2 billion, relative to the Base Case (with a net present value of $3.5 billion, using a 7 per cent real discount rate)
  – an increase of 36 per cent and 29 per cent respectively over findings of the supplementary report.

The extent to which the local residents will benefit from the additional economic output depends on the level of ownership of the capital (including the natural resources) utilised in the business as well as wealth transfers undertaken by Australian governments as a result of the taxation revenues generated by the Narrabri Gas Project.

Most of the real income benefit associated with the NGP is projected to accrue, in absolute terms, to residents outside of the Moree-Narrabri SA3 region. Despite this, there will be a significant and far greater per capita boost to the real incomes of people living in the Moree-Narrabri SA3 region than elsewhere in New South Wales.

6.4 Job creation

In addition to the direct jobs generated on-site, the construction and operation phases of the Narrabri Gas Project will require other New South Wales sourced goods and services including engineering and management services, transportation, OH&S and various business services. Supply of these inputs will further increase the demand for labour across the New South Wales economy.

A key issue when estimating the impact of a project is determining how the labour market will clear.[1] For this analysis, increases in the demand for labour in the Local Region can be met by three mechanisms: increasing migration from the rest of Australia; increasing participation rates and/or average hours worked; and by reducing the unemployment rate. In the model framework, the first two mechanisms are driven by changes in the real wages paid to workers in the local region while the third is a function of the additional labour demand relative to the Reference Case. Given the moderate

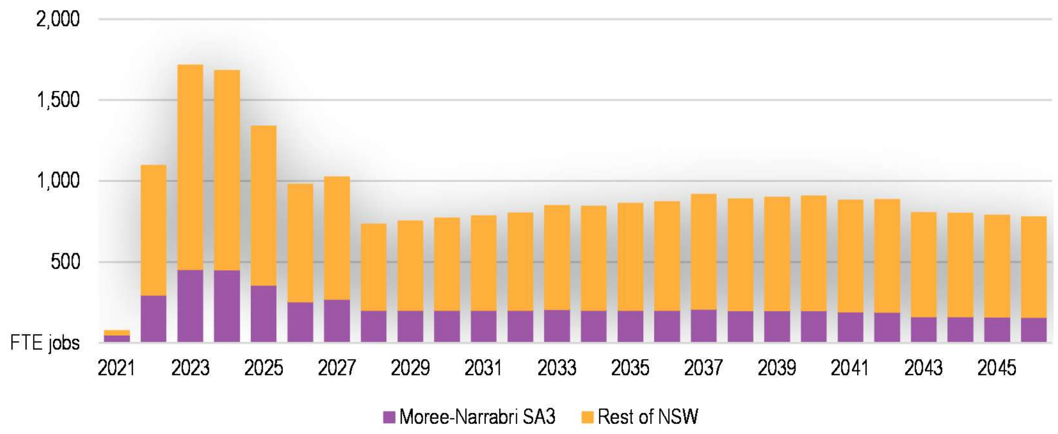
[1] As with other CGE models, the standard assumption within *Tasman Global* is that all markets clear (i.e. demand equals supply) at the start and end of each time period, including the labour market. CGE models place explicit limits on the availability of factors and the nature of the constraints can greatly change the magnitude and nature of the results. In contrast, most other tools used to assess economic impacts, including I-O multiplier analysis, do not place constraints on the availability of factors. Consequently, these tools tend to overestimate the impacts of a project or policy.

unemployment rate assumed throughout the projection period, changes in the real wage rate accounts for the majority of the additional labour supply in the policy scenarios relative to the Reference Case. In contrast, the previous assessment had a 'fully constrained' labour market, where national employment was fixed with constrained movement between regions.

It should be noted that this analysis does not assume any change in net foreign migration as a result of the Narrabri CSG project.

Over the life of the Narrabri Gas Project it is projected that an average of 912 full time equivalent direct and indirect jobs will be created in New South Wales. More specifically, over the period 2021 to 2046 it is projected that the Narrabri Gas Project will increase employment (by place of residence) in the Moree-Narrabri region by an average of 222 FTE job years each year

FIGURE 6.3 JOB CREATION: NARRABRI GAS PROJECT (FTE JOB YEARS)



SOURCE: ACIL ALLEN

These results reflect the impact of relaxing the assumption made in the earlier modelling of no growth in employment nationally.

6.5 Industry impacts

Table 6.2 shows the average impacts over the life of the Narrabri Gas Project on industry employment and output at the regional and state levels. The impacts shown do not include the Narrabri Gas Project within the mining industry; therefore, the industry effects shown relate only to the pre-existing mining industry. The results show employment and output change relative to baseline, i.e. relative to where they would be without the Project which was around 8 per cent.

TABLE 6.2 INDUSTRY EMPLOYMENT AND OUTPUT IMPACTS OVER THE PROJECT LIFE – PER CENT DEVIATION FROM THE BASELINE

	Employment		Output	
	Moree-Narrabri SA3 region	NSW	Moree-Narrabri SA3 region	NSW
Agriculture and forestry	-0.15	-0.03	-0.01	-0.01
Mining	0.05	0.02	0.04	0.02
Manufacturing	0.58	0.01	0.68	0.01
Utilities	0.15	0.01	0.24	0.00
Construction	0.82	0.01	0.66	0.01
Retail and wholesale trade	0.73	0.03	0.77	0.01
Transport	0.92	0.02	0.89	0.01

Services	0.74	0.02	0.70	0.00
TOTAL	**0.45**	**0.02**	**0.40**	**0.01**

NOTE: THE FIGURES ARE THE PERCENTAGE DEVIATION FROM A BASELINE WITHOUT THE NGP
SOURCE: ACIL ALLEN

The results in Table 6.2 demonstrate that on both an employment and output level, the impacts of the NGP are positive on most of the sectors shown. The negative impacts shown to agriculture and forestry are small and are likely mainly due to the assumed reduction in farmland, competition for labour and small increases in local costs. These are relative changes from the baseline and do not imply an absolute contraction in employment or output in the agricultural sector.

The positive benefits seen for the construction industry are mainly a result of demand from the project while wholesale and retail trade will benefit not only from project demand but from the increased levels of income at the regional and state levels.

Due to its domestic sales orientation, modest direct employment demand and relatively low land requirements, the Narrabri Gas Project has relatively little potential to have detrimental effects on NSW industries at the regional and state levels. The positive demand and income effects offset potential negative effects.

6.6 Comment

The updated inputs on capital expenditure and the relaxing of the constraint on employment growth nationally resulted in increased results for output, incomes and employment.

Gross regional product was 14 per cent higher for the Moree-Narrabri region and 23 per cent higher for NSW than in the earlier assessment, while the increase in real incomes was 38 per cent higher in the Moree-Narrabri region and 36 per cent for NSW.

A major reason for this was relaxing the employment constraint. The employment constraint assumed in the previous assessment limited the growth in economic activity and incomes. With this constraint relaxed, employment constraints in the Moree-Narrabri region are less limited and result in less crowding out of other economic activity and, accordingly, incomes. A fully unconstrained labour market assumption (where all additional labour demands generated by the project at the reference case real wages could be met without constraints) would be expected to have noticeably higher results for output, income and employment.

Growth in employment and output across industries was also higher than in the previous assessment. The rate of employment growth in the mining and manufacturing sectors is positive in the current assessment whereas it was slightly negative in the earlier assessment.

GLOSSARY OF TERMS

ADGSM	Australian Domestic Gas Security Mechanism
BCA	Benefit cost analysis
BCR	Benefit cost ratio
CSG	Coal Seam Gas
CTP	Capacity Trading Platform
DAA	Day Ahead Auction
DWGM	Victorian Declared Wholesale Gas Market
GJ	Gigajoule
GPG	Gas Fired Power Generation
GSH	Gas supply hub
GSOO	Gas Statement of Opportunities
LNG	Liquefied natural gas
MDQ	Maximum daily quantity
mmBTU	Million British Thermal Units
NGP	Narrabri Gas Project
NPV	Net present value
STTM	Short term trading market
TJ	Terajoule

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A

RESERVES AND RESOURCES

The following table is derived from data published by AEMO with the 2020 Gas Statement of Opportunities supplied to the ACCC by Core Energy Group.

TABLE A.1 EASTERN AUSTRALIAN GAS MARKET RESERVES AND RESOURCES

Basin	Project	2P developed	Production cost	2P undeveloped	Production cost	2C	Production cost	Prospective resources
		PJ	$/GJ	PJ	$/GJ	PJ	$/GJ	PJ
QLD								
Galilee	Galilee	-		-		2,417	8.32	622
Surat & Bowen	Surat / Bowen / Denison Conventional	69	2.85	53	5.95	120	7.00	-
Surat & Bowen	Moranbah	219	3.16	38	5.95	5,548	7.00	-
Surat & Bowen	QLD CSG - Arrow Energy (excl. Moranbah)	520	3.27	5,941	5.63	15,887	7.55	10,807
Surat & Bowen	QLD CSG - QCLNG	3,963	2.54	4,761	4.48	13,700	6.45	8,586
Surat & Bowen	QLD CSG - GLNG	1,397	3.02	4,492	6.60	1,355	9.44	-
Surat & Bowen	QLD CSG - APLNG	4,406	2.25	5,859	4.72	4,244	7.47	-
Surat & Bowen	QLD CSG - Other	176	3.81	1,130	6.74	3,832	8.87	-
Cooper	Cooper Eromanga Basin	757	2.44	252	6.36	5,850	7.12	144,564
Total QLD		**11,507**		**22,527**		**52,953**		**164,580**
NT								
Amadeus	Mereenie	93	3.13	93		193		3,604
Bonaparte	Blacktip	804	3.05	-		-	7.54	-
Total NT		**896**		**93**		**193**		**3,604**
Southern states								
Bass	Bass Basin	70	2.90	210	5.60	70	6.02	-
Sydney	Camden	28	3.13	-		-		-
Otway	Casino, Henry and Netherby	50	2.44	78	5.10	36	4.07	-
Clarence Moreton	Clarence Moreton	-	2.34	-		303	8.32	14,700
Gippsland	GBJV & Turrum & Kipper	1,119		1,154	5.50	686	7.43	4,062
Gippsland	Gippsland - Non-GBJV	-	2.44	-		3,526	7.54	4,696
Gunnedah	Gunnedah	-		-		971	6.40	3,502
Otway	Halladale/Blackwatch/Speculant	25	2.65	-	4.99	-	7.54	-
Gippsland	Longtom & Sole	-		328	5.70	130	5.80	50
Otway	Otway Gas Project	121	2.70	328	5.90	216	7.54	2,691
Total Southern States		**1,413**		**1,888**		**5,868**		**29,701**
Total		**13,824**		**24,718**		**59,085**		**197,885**

Note: Derived from data published by AEMO in conjunction with the 2020 GSOO. Data sourced by AEMO from Core Energy Group and gas industry participants.

SOURCE: (AEMO, FEBRUARY 2020)

B
GASMARK

GasMark Global (GMG) is a generic gas modelling platform developed by ACIL Allen. GMG has the flexibility to represent the unique characteristics of gas markets across the globe, including both pipeline gas and LNG. Its potential applications cover a broad scope — from global LNG trade, through to intra-country and regional market analysis.

GasMark Global Australia (GMG Australia) is an Australian version of the model which focuses specifically on the Australian market (including both eastern Australian and Western Australian modules), but which has the capacity to interface with international LNG markets.

B.1 Settlement

At its core, GMG Australia is a partial spatial equilibrium model. The market is represented by a collection of spatially related nodal objects (supply sources, demand points, LNG liquefaction and receiving facilities), connected via a network of pipeline or LNG shipping elements (in a similar fashion to 'arks' within a network model).

The equilibrium solution of the model is found through application of linear programming techniques which seek to maximise the sum of producer and consumer surplus across the entire market simultaneously. The objective function of this solution, which is well established in economic theory[6], consists of three terms:

— the integral of the demand price function over demand; minus
— the integral of the supply price function over supply; minus
— the sum of the transportation, conversion and storage costs.

The solution results in an economically efficient system where lower cost sources of supply are utilised before more expensive sources and end-users who have higher willingness to pay are served before those who are less willing to pay. Through the process of maximising producer and consumer surplus, transportation costs are minimised and spatial arbitrage opportunities are eliminated. Each market is cleared with a single competitive price.

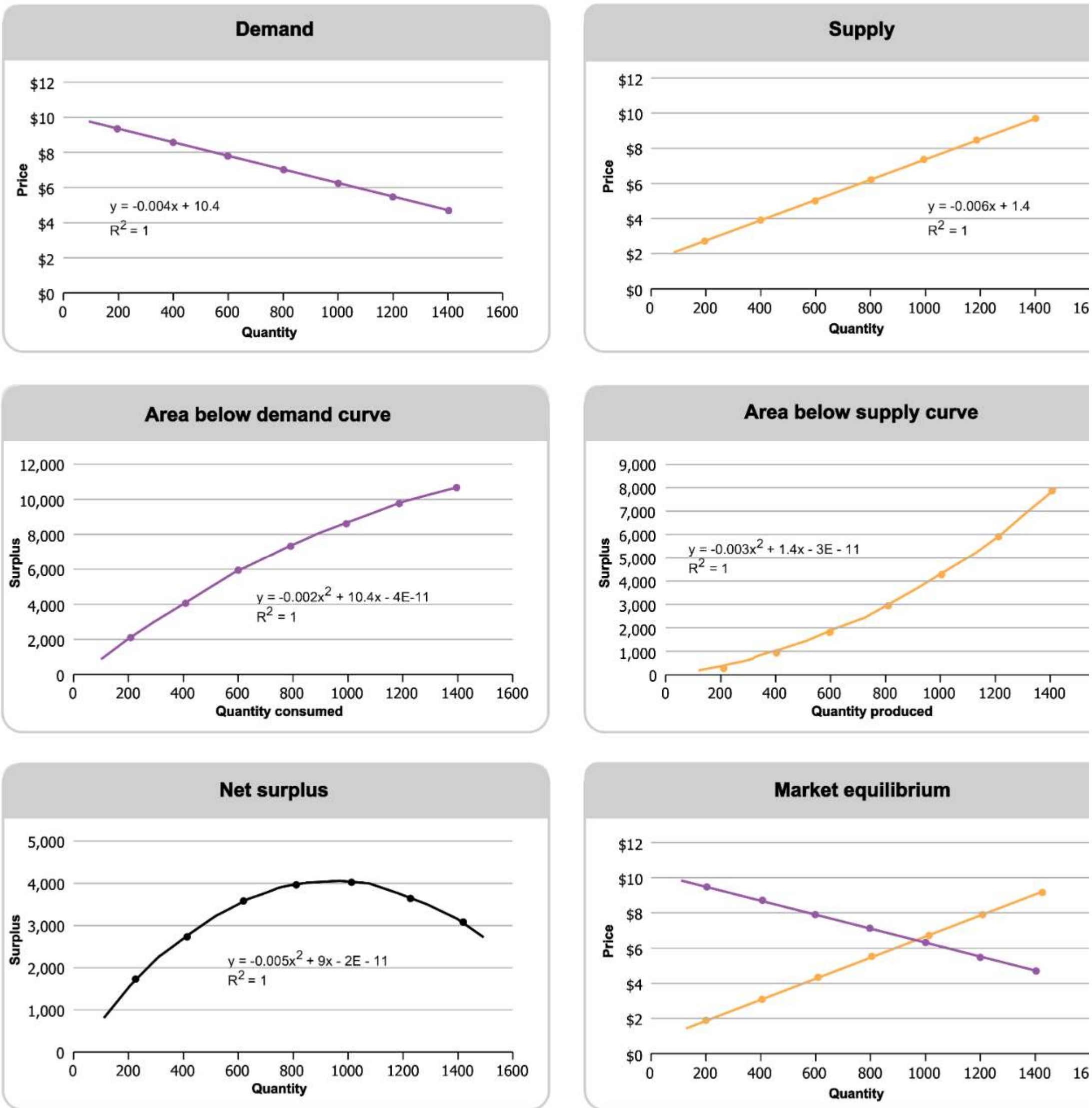
Figure B.1 seeks to explain diagrammatically a simplified example of the optimisation process. The two charts at the top of Figure B.1 show simple linear demand and supply functions for a particular market. The figures in the middle of Figure B.1 show the integrals of these demand and supply functions, which represent the areas under the demand and supply curves. These are equivalent to the consumer and producer surpluses at each price point along the curve. The figure on the bottom left shows the summation of the consumer and producer surplus, with a maximum clearly evident at a quantity of 900 units. This is equivalent to the equilibrium quantity when demand and supply curves are overlayed as shown in the bottom right figure.

6 The theoretical framework for the market solution used in GMG is attributed to Nobel Prize winning economist Paul Samuelson.

The distinguishing characteristic of spatial price equilibrium models lies in their recognition of the importance of space and transportation costs associated with transporting a commodity from a supply source to a demand centre. Since gas markets are interlinked by a complex series of transportation paths (pipelines, shipping paths) with distinct pricing structures (fixed, zonal or distance based), GMG Australia also includes a detailed network model with these features.

Spatial price equilibrium models have been used to study problems in a number of fields including agriculture, energy markets, mineral economics, as well as in finance. These perfectly competitive partial equilibrium models assume that there are many producers and consumers involved in the production and consumption, respectively, of one or more commodities and that as a result the market settles in an economically efficient fashion. Similar approaches are used within gas market models across the world.

FIGURE B.1 SIMPLIFIED EXAMPLE OF MARKET EQUILIBRIUM AND SETTLEMENT PROCESS



SOURCE: ACIL ALLEN CONSULTING

B.2 Data inputs

The user can establish the level of detail by defining a set of supply regions, customers, demand regions, pipelines and LNG facilities. These sets of basic entities in the model can be very detailed or aggregated as best suits the objectives of the user. A 'pipeline' could represent an actual pipeline or a pipeline corridor between a supply and a demand region. A supplier could be a whole gas production basin aggregating the output of many individual fields or could be a specific producer in a smaller region. Similarly, a demand point could be a single industrial user or an aggregation of small consumers such as the residential and commercial users typically serviced by energy utility companies.

The inputs to GMG Australia can be categorised as follows:

— **Existing and potential new sources of gas supply**: these are characterised by assumptions about available reserves, production rates, production decline characteristics, and minimum price expectations of the producer. These price expectations may be based on long-run marginal costs of production or on market expectations, including producer's understandings of substitute prices. The "gas field" objects in the model can also be used to represent LNG import terminals since these are, in effect, simply alternative sources of gas supply that are not subject to intrinsic reserves limits or production decline functions, but that have similar characteristics in terms of minimum selling prices (representing cost of purchasing LNG plus terminal costs) and maximum delivery (production) rates.

— **Existing and potential new gas demand**: demand may relate to a specific load such as a power station, or fertiliser plant. Alternatively, it may relate to a group or aggregation of customers, such as the residential or commercial utility load in a particular region or location. Loads are defined in terms of their location, annual and daily gas demand including daily demand profiles, and price tolerance.

— **Existing, new and expanded transmission pipeline capacity**: pipelines are represented in terms of their geographic location, physical capacity (which may vary over time), flow characteristics (uni-directional or bi-directional) and tariffs.

— **Existing and potential new LNG facilities**: LNG facilities include liquefaction plants, regasification (receiving) terminals and assumptions regarding shipping costs and routes. LNG facilities play a similar role to pipelines in that they link supply sources with demand. LNG plants and terminals are defined at the plant level and require assumptions with regard to annual throughput capacity and tariffs for conversion.

Existing and potential gas storage facilities: storage facilities (whether UGS or LNG) are defined in terms of total storage capacity, maximum injection and withdrawal rates, cushion gas requirements, storage losses, and price limits for purchase of gas into storage and sale of gas from storage. Storage charges are taken into account via tariffs on the pipelines connecting storage facilities into the transmission pipelines system.

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