Commercial Viability of the Narrabri Gas Project

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Pegasus Economics is a boutique economics and public policy consultancy firm that specialises in strategy and policy advice, economic analysis, trade practices, competition policy, regulatory instruments, accounting, financial management and organisation development.

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Photograph on the front cover is from coal seam gas waste water processing infrastructure in the Pilliga forest – image from the film, Pilliga Rising. Credit | Mark Pearce.

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Executive Summary

In early March, an OPEC negotiation to address over-production failed, triggering a dramatic collapse in international oil and gas prices just as the global Covid-19 outbreak was accelerating.

Lock the Gate commissioned Pegasus Economics to assess what bearing, if any, this price slump would have on the justification and prospects for the Narrabri Gas Project (NGP).

The NGP is a production gas field for coal seam gas (CSG) proposed by Santos about 20km south-west of the town of Narrabri in the central portion of the Gunnedah Basin. In February 2016, Santos downgraded its proven and probable reserves in the Gunnedah Basin as contingent resources (Santos 2016a). The value of Santos' assets in the Gunnedah Basin are currently listed as zero on its balance sheet.

The context for the project is the Eastern Gas Region, an interconnected gas grid connecting all of Australia's eastern and southern states and the Australian Capital Territory (ACT) (Australian Energy Market Commission, 2019). For decades, the Eastern Gas Region operated in isolation from other gas markets in Australia and overseas: there were no gas exports from or imports into the region (Jacobs SKM, 2014, p. 4). Starting in the late 1990's, CSG from Queensland began to enter the Eastern Gas Region (Forcey & McConnell, 2017, p. 10) and by 2007, estimated CSG resources had outgrown the requirements of the domestic market and CSG developers sought monetisation of the resource in new, larger markets, the most accessible of which were Asian liquid natural gas (LNG) markets (Jacobs SKM, 2014, p. 11).

Three LNG projects were conceived, approved and constructed, all located at Curtis Island near Gladstone in Queensland. As a result, the majority of Eastern Gas Region's gas reserves, which are located in the Surat and Bowen Basins in Queensland, are now largely committed to the LNG export industry (Australian Energy Regulator, 2018, p. 201) and consumption of natural gas from the LNG export projects now dwarfs the domestic market (Bethune & Wilkinson, 2019, p. 520). In 2019 LNG exports accounted for almost 69 per cent of natural gas consumption in the Eastern Gas Region (Australian Energy Market Operator, 2020).

The Eastern Gas Region is simultaneously producing record volumes of gas and continually predicted to be under threat of supply shortfalls. Supply of natural gas in the Eastern Gas Region has tightened since the Queensland LNG export projects do not rely solely on their own gas resources, but also draw on other gas resources within the Eastern Gas Region (Australian Energy Regulator, 2017, p. 8).

This is particularly the case for the LNG export project led by Santos, Gladstone LNG (GLNG). While the other two the Queensland LNG export projects primarily expected to meet their LNG export commitments through the new development of gas resources owned by them, the Santos-led GLNG always expected to source gas from other producers and existing sources in the Eastern Gas Region to supplement its CSG reserves (Australian Competition and Consumer Commission, 2016, p. 28). And this expectation was fulfilled: the Santos-led GLNG project has diverted natural gas from domestic users to export markets to fulfil its export contracts and it has been the major contributor towards any impending natural gas shortfalls within the Eastern Gas Region.

Santos has used the pretext of looming gas supply shortages in NSW as a fulcrum to garner regulatory approval for its NGP without acknowledging the central role it played in creating the circumstances that it now claims the NGP will address. The development of the NGP would provide some additional gas supply, but the Australian Energy Market Operator (2020, p. 52) has suggested that an LNG import terminal would delay future gas supply shortages for the southern states longer than the development of the NGP.

The estimated production costs of the NGP are $6.40 per gigajoule (GJ), with a delivered cost to Sydney somewhere in the order of $7.60 to $8.40 per GJ, making it a comparatively high cost gas development. There are 30 (15 developed and 15 undeveloped) Eastern Gas Region gas projects with lower estimated production costs than the NGP.

Given this context, there appear to be three main risks to the commercial viability of the NGP:

1) imported gas from Queensland currently contracted to LNG export markets redirected towards the domestic market due to the growing gap between spot prices and contract prices
2) the development of an LNG import terminal
3) the discovery and development of lower cost gas resources in the Eastern Gas Region.

The three Queensland LNG export projects are understood to be underwritten by long-term contracts of 20 years, with LNG prices linked to crude oil prices coupled with take-or-pay provisions.

The LNG prices linked to crude oil prices are based on the Japanese Customs-Cleared Crude Oil price, colloquially referred to as the Japan Crude Cocktail (JCC) price mechanism, a published index of the prices of crude oils imported into Japan (Rogers & Stern, 2014, p. 1).

Bruce Robertson (2017, p. 4) from the Institute for Energy Economics and Financial Analysis has observed that in all resource markets, highest-cost producers have to curtail production first, and that the three Queensland LNG export projects "sit at the very apex of the global cost curve, so these plants will feel the pressure to shut in capacity most acutely." The breakeven point for the three Queensland LNG export projects is at an average oil price of around US$29-32 per barrel.[1] While ongoing low crude oil prices would provide an incentive for the Queensland LNG export projects to cut back on their LNG export sales due to the prospect of incurring losses, crude oil prices below US$30 per barrel are unlikely to persist.

By late May 2020, crude oil prices had recovered from recent lows of less than US$20 per barrel and were above US$30 per barrel. Crude oil prices are likely to gradually recover and remain above the breakeven point for the Queensland LNG export projects, thus ensuring the Queensland LNG export projects will remain viable, provided their long-term supply contracts remain in force. On this basis, low crude oil prices do not pose an immediate threat to the commercial viability of the NGP as they are unlikely to result in the redirection of Queensland CSG back into the domestic market.

However, increasing quantities of Queensland gas could be redirected to the domestic market for another reason. The significant gap that has opened up between LNG spot prices and the long-term LNG contract prices based on the JCC does pose a risk to the commercial viability of the NGP. Unlike low crude oil prices, this gap is likely to persist and grow as likely long-term supply contract prices for the Queensland LNG export projects are expected to remain much higher than the cost of procuring LNG from the US Gulf Coast. Trade on a spot basis and under short-term contracts of less than four years has increased from just under 14 per cent of all Asian LNG imports in 2009 to almost 31 per cent in 2019.[2] This price dynamic creates incentives for buyers to take the minimum possible volumes allowed for under long-term LNG supply contracts, renegotiate and/or even renege on contractual terms.

As high cost suppliers of LNG, the Queensland LNG export projects are not price competitive with other international suppliers, suggesting that increasing quantities of Queensland CSG gas production could eventually be redirected back into the domestic market. In turn this provides a serious threat to the commercial viability of the NGP that has much higher expected production costs than existing Queensland CSG projects.

High local prices create another risk for the NGP. The raising of wholesale gas prices above the level they should be presents a market opportunity for LNG imports into the Eastern Gas Region that

[1] See Origin Energy (2020, p. 51).
[2] See International Group of Liquified Natural Gas Importers (2010; 2020).

poses a long-term and continuing risk to the commercial viability of the NGP. Paradoxically, Santos' own business strategies may be elevating this risk.

The ACCC has implied that Queensland gas producers may be exercising market power to maintain higher gas prices in the Eastern Gas Region.[3] The prevailing market structure and the characteristics of natural gas lend support to the ACCC's implication and a level of tacit collusion may be underpinning current domestic pricing of the three Queensland LNG export projects. Further adding to concerns the Queensland LNG export projects may be exercising market power, there are longstanding concerns that there has been hoarding of gas reserves.

Despite claims to the contrary, LNG imports into the Eastern Gas Region can be price competitive, if not undercut, gas produced and transported to Sydney from the NGP. Arguably, the proposed LNG import terminal at Port Kembla is competing directly against the NGP for commercial viability with only one project likely to proceed.

In relation to the third risk, it has been suggested that Victoria's onshore gas basins could in fact house Australia's second largest gas reserves (Gottliebsen, 2019), although there is no evidence of gas resources present of this magnitude. Even if such gas resources were present in Victoria's onshore basins, it would still take several years to properly assess and then extract if they proved to be commercially viable.

Even if Santos is granted planning approval to proceed with the NGP, there are reasons to believe the company would not proceed to a final investment decision any time soon. There have been longstanding concerns expressed that the Queensland LNG export projects have been hoarding, banking and warehousing CSG gas reserves, perhaps in order to maintain tacitly collusive gas pricing. As a part-owner of one of the Queensland LNG export projects, presumably Santos is subject to the same incentives as the other operators and affiliates. In the current environment for oil and gas prices, Santos would be unlikely to commit the capital investment of $3.57 billion that is required for the development of the NGP, let alone the ongoing project operating costs of $5.47 billion over 25 years, especially given its decision to cut capital expenditure and investment decisions on other projects earlier this year.

Our findings indicate the divergence of Asian LNG spot prices from the oil-linked JCC contract prices since late 2018 could well mean that Asian buyers continue to increase the proportion of LNG imports purchased on the spot market, thereby prompting more CSG from Queensland to be redirected into the domestic market, eroding the market justification for the NGP. Furthermore, LNG imports into the Eastern Gas Region can be price competitive, if not undercut, gas produced and transported to Sydney from the NGP, thereby undermining the commercial viability of the NGP.

[3] See ACCC (2020, p. 58).

1. Introduction

Lock the Gate has commissioned Pegasus Economics to assess the implications for the economic viability of the Narrabri Gas Project (NGP) arising from recent falls in the price of crude oil and natural gas. This follows the referral by the NSW Minister for Planning and Public Spaces, the Hon. Rob Stokes MP, of the NGP to the Independent Planning Commission for determination on 3 March 2020.

International crude oil and natural gas prices have fallen dramatically since the COVID-19 coronavirus outbreak. The dramatic price falls in crude oil were exacerbated when a price war broke out between Russia and Saudi Arabia following the breakdown of talks between the Organization of the Petroleum Exporting Countries (OPEC) and Russia over proposed oil-production cuts in the midst of the COVID-19 outbreak in early March 2020.

The views and opinions expressed in this report are entirely those of the authors.

2. Natural Gas

2.1 Natural Gas Deposits

Natural gas comprises gases occurring in deposits, whether liquefied or gaseous, consisting primarily of methane (International Energy Agency, 2018, p. 1.3).

Natural gas commonly exists in mixtures with other hydrocarbons, principally ethane, propane, butane, and pentanes, also known as 'natural gas liquids' (NGLs) (Naturalgas.org, 2013). In addition, raw natural gas contains water vapor, hydrogen sulfide, carbon dioxide, helium, nitrogen, and other compounds.

A basin is a geological formation creating a depression, or dip, in the Earth's surface (National Geographic, 2011). Basins are shaped like bowls, with sides higher than the bottom and structural basins are formed by tectonic activity. Tectonic activity is the movement of large pieces of the Earth's crust, called tectonic plates. The natural processes of weathering and erosion also contribute to forming structural basins. Structural basins form as tectonic plates shift. Rocks and other material on the floor of the basin are forced downward, while material on the sides of the basin are pushed up.

Sedimentary basins are a type of structural basin sometimes forming long troughs (National Geographic, 2011). Over millions of years, the remains of plants and animals build up in thick layers on the earth's surface and ocean floors, sometimes mixing with sand, silt, and calcium carbonate (U.S. Energy Information Administration, 2018). These layers are buried under sand, silt, and rock, and with subsequent pressure and heat changes this carbon and hydrogen-rich material is converted into coal, crude oil, or natural gas.

In some places, natural gas moved into large cracks and spaces between layers of overlying rock (U.S. Energy Information Administration, 2018). The natural gas found in these types of formations is referred to as conventional natural gas. In other places, natural gas occurs in the tiny pores (spaces) within some formations of coal, shale, sandstone, and other types of sedimentary rock. This natural gas is referred to as unconventional natural gas.

Unconventional gas is created in more complex geological formations which limit the ability of gas to easily migrate and therefore different extraction methods are required as compared to conventional gas deposits (NSW Environment Protection Authority, 2015, p. 1).

There are several types of unconventional gas, including shale gas and tight gas, which occur in reservoirs that have very low permeability compared to conventional reservoirs (NSW Environment Protection Authority, 2015, p. 1). Shale gas is mainly methane trapped within shale rock layers at depths greater than about 1,500 metres (CSIRO, 2019). Tight gas refers to natural gas resources that are sealed in extremely impermeable, hard rock, making the underground formation extremely 'tight' and difficult to access (Rajput & Thakur, 2016).

Coal seam gas (CSG) is a form of natural gas, typically extracted from coal seams at depths of 300-1000 metres (CSIRO, 2019). It is mostly made up of methane.

2.2 Natural Gas Production

Production wells used to extract gas from subsurface deposits are drilled through the earth directly into gas deposits contained in underground formations (Kegler Brown Hill + Ritter, 2014). Natural gas wells can be drilled vertically and horizontally into natural gas-bearing formations (U.S. Energy Information Administration, 2018). In conventional natural gas deposits, the natural gas generally flows easily up through vertical production wells to the surface.

In shale gas and tight gas geological formations, horizontal drilling and fracking are often necessary for economic gas extraction (NSW Environment Protection Authority, 2015, p. 1). Horizontal drilling involves the production well changing from a vertical to a horizontal direction underground (Scientific Inquiry into Hydraulic Fracturing of Onshore Uconventional Reservoirs in the Northern Territory, 2017, p. 6). Fracking refers to the injection of fluid (comprising approximately 99.5 per cent water and proppant (sand) and approximately 0.5 per cent chemical additives) at high pressure into targeted sections of the layers of gas-bearing rocks (Scientific Inquiry into Hydraulic Fracturing of Onshore Uconventional Reservoirs in the Northern Territory, 2017, p. 7). This creates localised networks of fractures that unlock gas and allow it to flow into the well and up to the surface.

To extract CSG, a steel-encased well is drilled vertically into the coal seam at which point the well may also be fracked or drilled horizontally along the coal seam to increase access to the gas reserves (NSW Environment Protection Authority, 2015, p. 2). The extraction of CSG does not always require fracking, but does require the removal of water from the coal to unlock the gas (dewatering) (Scientific Inquiry into Hydraulic Fracturing of Onshore Uconventional Reservoirs in the Northern Territory, 2017, p. 5). Large amounts of water with salt and sometimes other contaminants are produced in this process.

Once the gas is extracted from the wellhead, it is sent to processing plants (U.S. Energy Information Administration, 2018). Natural gas processing involves separation of the various hydrocarbons, fluids and other contaminants from the natural gas (Naturalgas.org, 2013). The NGLs can be very valuable by-products of natural gas processing (Naturalgas.org, 2013), and can be used as inputs for petrochemical plants, burned for space heat and cooking, and blended into vehicle fuel (U.S. Energy Information Administration, 2012). Ethane occupies the largest share of NGL field production and is used almost exclusively to produce ethylene, which is then turned into plastic. Blends of propane and butane are more commonly known as liquid petroleum gas (LPG).

Unconventional gas, in particular CSG, has been subject to much public criticism which has focused on issues such as the environmental impacts of extraction and the legal rights of landholders whose properties are subject to CSG exploration or production (Select Committee on the Supply and Cost of Gas and Liquid Fuels in New South Wales, 2015, p. 3). This is due to concerns about the impact it may have on water resources and public health, and the potential for wells and associated infrastructure to impact upon farmland and rural communities.

2.3 Applications of Natural Gas and the Domestic Supply Chain

Natural gas plays a very important role in our society as a raw material for a great variety of industrial processes (Abánades, 2018). Its utilisation as a primary energy source has been consolidated during the past few decades due its high hydrogen/carbon ratio, efficient combustion, and lower amounts of contaminants in the exhausted gases, including lower carbon dioxide emissions than coal when used for electricity generation.

Natural gas has a wide range of applications including as a feedstock for gas powered generators (GPG) for electricity production, and as a power source for appliances such as gas heaters, gas water heaters and gas stoves. Natural gas for electricity generation is complementary for renewable energy due to its lower carbon dioxide emissions and reliability as an energy source capable of being switched up and down quickly to deal with peaking demand and the intermittency of wind and solar power electricity generation (Gallagher, 2018, p. 6). Rapid changes in electricity generation power output from variable renewable energy generation need to be balanced with generation technology that has the ability to increase (ramp up) or decrease (ramp down) power output at the same time and gas-fired generators have the ability to 'fast ramp' (Finkel, Moses, Munro, Effeney, & O'Kane, 2017, p. 107).

Natural gas is also an important input in many industrial processes, including for the production of pulp and paper, metals, chemicals, stone, clay, glass and processed foods (Australian Energy Regulator, 2018, p. 183). It is also a major feedstock in ammonia production for fertilisers and explosives.

Gas producers sell wholesale gas domestically to electricity generators, to other large gas users and to energy retailers, who then on-sell the gas to businesses and household customers (Australian Competition and Consumer Commission, 2018b, p. 5). The gas produced for domestic consumption is transported ('shipped') through high pressure transmission pipelines from the production facility to the entry point of the distribution network ('city gate') or to large users (for example, large commercial and industrial users) connected to the transmission pipeline.

Gas distribution pipelines transport natural gas from transmission pipelines to end users (Australian Competition and Consumer Commission, 2018b, p. 5). These typically consist of a backbone of high and medium pressure pipelines running between the city gate and major demand centres. This pipeline system feeds low pressure pipelines which deliver the gas to businesses and homes. Energy retailers act as intermediaries by buying gas from producers and packaging it with pipeline services for sale to residential, commercial and small business customers.

2.4 Natural Gas Exports

International trade in natural gas occurs through two modes of transport – pipelines and sea freight. Where natural gas pipelines are not feasible or do not exist, liquefying natural gas is a way to move natural gas from producing regions to markets (U.S. Energy Information Administration, 2019). Natural gas liquefies at minus 161.5 degrees Celsius, at which temperature it reduces to 1/630 times its original volume (Stopford, 2009, p. 606).

A liquefaction plant has one or more 'trains' which liquefy the gas (Stopford, 2009, p. 486). A train is a compressor, usually driven by a gas turbine, which compresses a coolant until it reaches minus 163 degrees Celsius, at which temperature the gas is reduced in volume and feeds into cooling coils which liquefy the gas passing over them. This liquid natural gas (LNG) is stored in refrigerated tanks until a ship arrives and transports it to its destination.

LNG tankers (or transport ships) rely on insulation to prevent the gas from reliquefying during transit (Stopford, 2009, p. 486). While the tanks on an LNG tanker are designed to stay cool, they cannot provide perfect insulation against warming (Fluenta, 2018). Heat slowly affects the tanks, which can cause the LNG inside to evaporate and produces a substance known as boil-off gas (BOG). When boil-off occurs and the methane returns to gas, the larger volume of gas will increase the tank pressure. To relieve the pressure in LNG tanks, BOG can be re-liquefied, used as fuel in the ship's engines or burned in a gasification unit.

At its destination, a regasification plant at an import terminal turns the LNG back into natural gas, and feeds it into a power utility or the local pipeline system (Stopford, 2009, p. 487).

There are two basic types of LNG import terminals: onshore land-based terminals and Floating Storage Regasification Units (FRSUs) (Department of Industry, Innovation and Science, 2018, p. 101). The FSRUs and onshore LNG import terminals both take up LNG, regasify it by taking it from a liquid and expand it back into a gas (Mishra, 2018).

An onshore land-based terminal consists of a terminal to receive LNG tankers, LNG storage tanks, regasification equipment, and generally an entry point to a pipeline network to deliver gas to customers. A FSRU is essentially a floating LNG import terminal. The FSRUs are custom-built vessels, similar to LNG tankers but with an ability to transform LNG back to the gaseous state (Mishra, 2018). Like an onshore land-based terminal, FSRUs generally need a berth for the LNG tanker, storage tanks and pipelines.

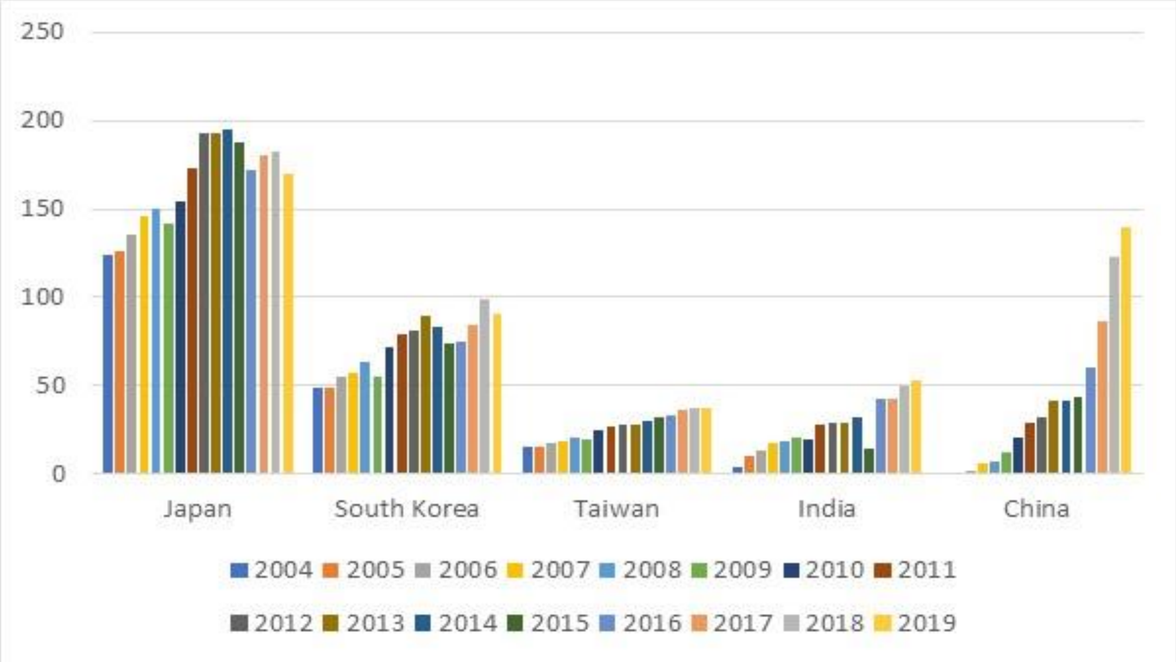
While onshore LNG terminals can take between 5 and 7 years to plan, construct and bring online, FSRUs require little construction or investment, can provide access to LNG much faster, and cost less than half the cost of an onshore facility (Mishra, 2018). Most FSRUs are leased as the vessel is owned by a shipping company and can be reassigned on project completion (Songhurst, 2017, p. 33). This provides a major advantage over onshore LNG import terminals where the construction cost represents a sunk cost.

However, while conventional onshore LNG import terminals have much larger construction costs than FRSUs, they are much cheaper to operate (International Gas Union, 2019, p. 73). A conventional onshore LNG import terminal also usually has a greater gas storage capacity, compared to an FSRU (International Gas Union, 2019, p. 93). This offers long-term supply security for the market and therefore provides a more permanent solution.

As of February 2019, nearly 85 per cent of existing LNG import terminals were located onshore (International Gas Union, 2019, p. 78). However, after more than 10 years of operations, FRSUs are considered a proven and reliable for use in LNG import terminals (International Gas Union, 2019, p. 93).

During 2019, 42 countries imported LNG with Asia accounting for 69.4 per cent of global LNG imports (International Group of Liquefied Natural Gas Importers, 2020). Details on the import volumes of the five largest importing countries since 2004 who account for almost 62 of global LNG imports is provided in Figure 1 below.

Figure 1: LNG Imports by the Five Largest Importing Countries – 2004 to 2019 (10^6 m^3 liquid)



Source: International Group of Liquified Natural Gas Importers (2020).

3. Narrabri Gas Project

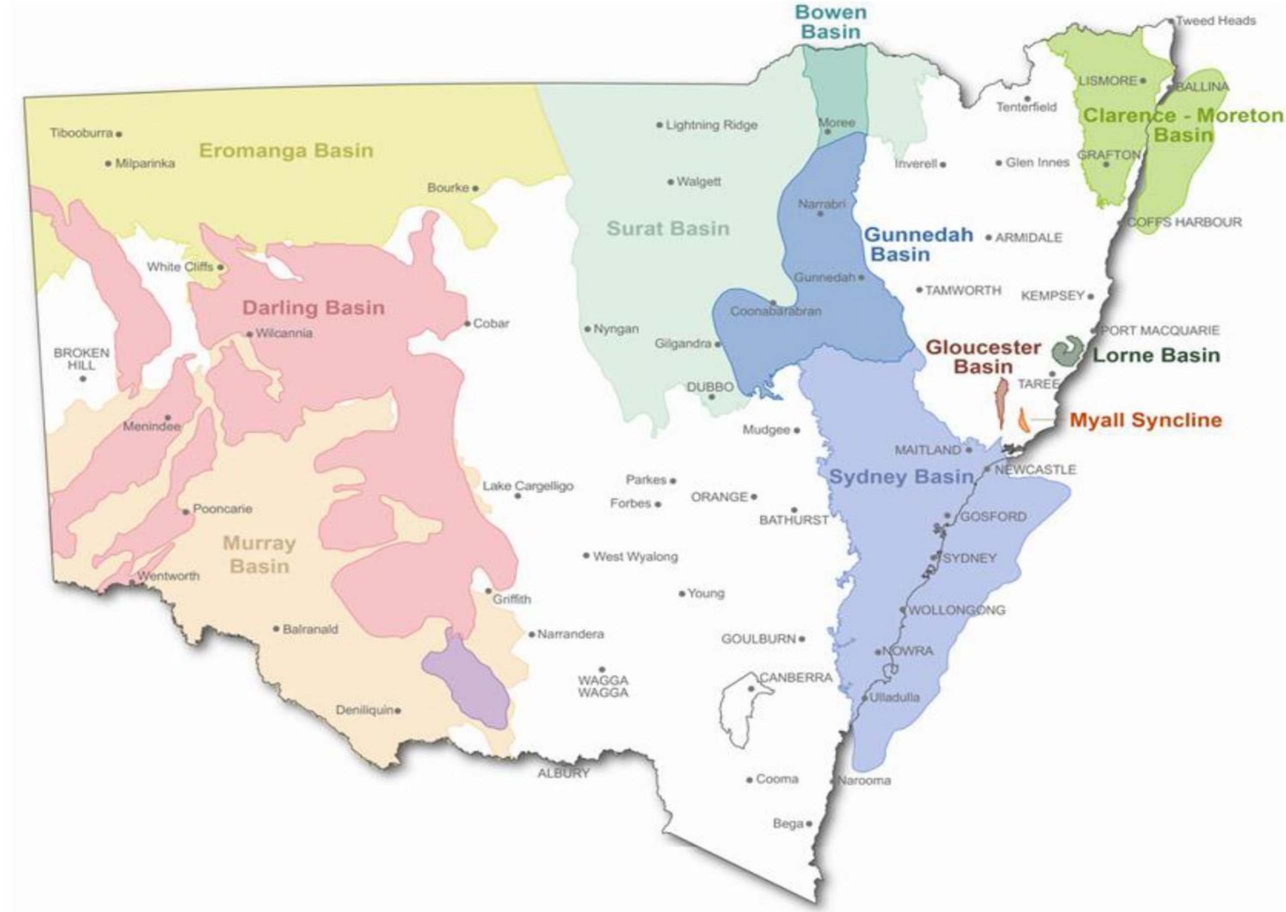
3.1 Gunnedah Basin

The Gunnedah Basin is a structural trough in northeast New South Wales (NSW) (O'Kane, 2013, p. 43). The basin appears continuous with the Bowen Basin in the north and the Sydney Basin in the south. The Great Artesian Basin overlies the Gunnedah Basin. The Gunnedah Basin covers an area of approximately 15,000 km^2 (Welsh, et al., 2014, p. 37).

The Gunnedah Basin is divided into two sub-basins of unequal portions by the north−south-trending Boggabri Ridge (Department of Planning and Environment, 2017).

A map of the Gunnedah Basin along with other NSW sedimentary basins is provided below in Figure 2.

Figure 2: New South Wales Sedimentary Basins



Sources: O'Kane (2013, p. 42) taken from (NSW Division of Resources and Energy (Cartographer), 2013).

Several areas of the Gunnedah Basin have been indicated as having potential for CSG resources (O'Kane, 2013, p. 43).

3.2 Narrabri Gas Project

The NGP proposes to extract natural gas resources from CSG about 20 km south-west of the town of Narrabri in the central portion of the Gunnedah Basin (GHD, 2017).

The project area contains a portion of the Pilliga forest, with the majority of the project located on Crown land (GHD, 2017, p. 1.1). The Pilliga forest is an agglomeration of forested areas covering more than 500,00 hectares around Coonabarabran, Baradine and Narrabri. The majority of native vegetation on more productive soils in the surrounding area has been cleared for agriculture, with the Pilliga forest left as a large dry woodland remnant on the poorest sandy soils (Murphy & Murphy, 2015, p. 517). The landform of the Pilliga forest ranges from low sandstone hills and broad sandy valleys in the south-east to a flat outwash sand plain in the west and north. The NGP covers the Pilliga north of Coonabarabran and the eastern part of the Pilliga outwash, and bordering the northern end of the Liverpool Plains (Herr, et al., 2018, p. 12). The Liverpool Plains supports highly valuable agricultural development including cropping of cotton and grains, with the less arable soils being under livestock grazing (Herr, et al., 2018, p. 10).

The NGP has been proposed by Santos NSW (Eastern) Pty Ltd, a wholly owned subsidiary of Santos Ltd (Santos), an Australian oil and gas company listed on the Australian Securities Exchange. Santos will operate the project on behalf of its joint venture participants (GHD, 2017, p. 1.1).

The NGP would include the progressive installation of up to 850 new gas wells on up to 425 new well pads over approximately 20 years and the construction and operation of gas processing and water treatment facilities (GHD, 2017, p. ES.1).[4]

Santos (2017a) states that it is intending to make the gas extracted by the NGP available to NSW via a pipeline linking into the existing Moomba to Sydney Pipeline.

Small amounts of CSG are currently being generated from the NGP exploration wells to supply gas to the Wilga Park Power Station (General Purpose Standing Committee No. 5., 2012, p. 11) providing electricity for the equivalent of about 23,000 households in northwest NSW (Santos Ltd, 2019a). The Wilga Park Power Station is located to the west of Narrabri (Eastern Star Gas Limited, 2010). The Wilga Park Power Station was originally supplied with gas produced from the conventional Coonarah Gas Field, but when this field failed to live up to production expectations, it was closed down (Eastern Star Gas Limited, 2010, p. 10). Following the installation of pipeline infrastructure, the Wilga Park Power Station was instead supplied with gas from CSG fields at Bibbiwindi and Bohena (Eastern Star Gas Limited, 2010, p. 28).

In July 2012 the NSW Environment Protection Authority (EPA) (2012) issued Eastern Star Gas, the former operator of the NGP, with two penalties and fines of $3,000 for discharging polluted water to Bohena Creek in the Pilliga Forest. In February 2014 the EPA (2014) issued a $1,500 fine to Santos NSW (Eastern) Pty Ltd following a pollution incident at their Narrabri Gas Field operations in the Pilliga. In May 2015 the EPA (2015a) completed investigations into two separate incidents that occurred at the NGP in 2013 and 2015. Although the investigations showed that neither of these incidents resulted in any significant environment impacts, the EPA did express concerns with aspects of the site operations and management.

In its 2014 investor seminar, Santos (2014, p. 66) announced that its proven and probable gas reserves in the Gunnedah Basin were likely to be 30 per cent lower than its year-end estimates in 2013. On 12 February 2015 Santos (2015b) announced an impairment charge of $808 million before tax on the NGP following the downgrading of its proven and probable gas reserves in the Gunnedah Basin.

Similarly, in February 2015, CLP Holdings (2015, p. 72), the Hong Kong based parent company of EnergyAustralia that holds a minority stake in NGP, also announced an impairment provision for the NGP:

> *In 2014, an impairment provision of HK$1,578 million (A$248 million) was made on the Narrabri Coal Seam Gas Project, in which EnergyAustralia holds a 20% interest. The provision was made based on additional drilling data and analysis that reflected a reduction in the estimated total gas reserves and a fall in estimated daily production.*

In February 2016 Santos (2016a) downgraded its proven and probable reserves in the Gunnedah Basin to contingent resources. Also in February 2016 Santos (2016, p. 61) booked another impairment charge of $588 million on the NGP, writing down the book value of the project to zero.

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[4] The first stage in the life cycle of a well once a location has been selected is to prepare a well pad for drilling (Huddlestone-Holmes, Measham, Jeanneret, & Kear, 2018, p. 4). Well pads are typically 1 to 1.5 hectares in area and provide the working area for drilling operations. They are usually prepared using earthworks machinery to level the site and clear vegetation. Aggregate may be laid down to allow all-weather access and operations of the drill rig. Topsoil is stockpiled at the site so that it can be put back in place during rehabilitation of the site. The well pad may have one or two sumps to store water, catch drill cuttings and hold drilling mud during operations. These sumps have a capacity of around 100,000 litres. The well may also have a flare pit to contain ground flares that allow for the controlled burning of gas from the well.

In December 2016 Santos (2016b) relegated the NGP to the status of a “non-core asset” which would be run as a standalone business. Santos’ announced policy in relation to its non-core assets was to optimise value through sweating or exiting the assets.

At its 2017 Investor Day in November 2017, Santos (2017) announced the NGP would join the company’s core asset portfolio. Despite this, the value of Santos’ assets in the Gunnedah Basin are still listed as zero on its balance sheet.[5]

3.2.1 Gas Resources in the Gunnedah Basin

Reserves are those quantities of natural gas anticipated to be commercially recoverable by a project from known accumulations from a given date forward (Society of Petroleum Engineers, 2017, p. 3). Reserves must satisfy four criteria: discovered, recoverable, commercial, and remaining. Reserves are most commonly reported at the proven plus probable reserves or 2P level where there is a 50 per cent probability that the actual quantities recovered will exceed the estimate (Society of Petroleum Engineers, 2017, p. 13).

Natural gas can also be reported as contingent resources and prospective resources. Contingent resources are quantities of natural gas estimated, as of a given date, to be potentially recoverable from known accumulations, by the application of a project not currently considered to be commercially viable due to one or more contingencies (Society of Petroleum Engineers, 2017, p. 4). Contingent resources are commonly reported on a 2C basis which refers to the best estimate of contingent resources (Society of Petroleum Engineers, 2017, p. 38).

Prospective resources are those quantities of natural gas estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future projects (Society of Petroleum Engineers, 2017, p. 4). Prospective resources are commonly reported on a 2U basis which refers to the unrisked best estimate qualifying as prospective resources.

The Australian Energy Market Operator (AEMO) (2020) reports contingent resources (2C) of 971 petajoules (PJ) and prospective resources (2U) of 3,502 PJ for the NGP.[6] As discussed above, in February 2016 Santos (2016a) downgraded its proven and probable (2P) reserves in the Gunnedah Basin as contingent resources and hasn’t provided an update since. Grossing up the Santos share of the NGP to account for the entire project provides an estimate of contingent resources in the Gunnedah Basin consistent with the level of 2C resources reported by the AEMO. This is outlined in Table 1 below.

Table 1: Estimates of Gas Resources in the Gunnedah Basin (PJ)

Resource category	Australian Energy Market Operator	Narrabri Gas Project*
Reserves		
Contingent resources	971	971
Prospective resources	3,502	

Sources: AEMO (2020) and Santos (2015; 2016a).
* The Santos share of reported gas reserves in the Gunnedah Basin that were reclassified as contingent resources were grossed up to account for the entire NGP.

3.2.2 Production from the Narrabri Gas Project

It is claimed the NGP has the capacity to deliver up to 200 terajoules (TJ) of gas per day (GHD, 2017, p. 1.11). This converts to an annualised figure of 73 PJ. It was claimed in the Preliminary Environmental Assessment that the project would have the capacity to produce approximately 70 PJ of gas per annum (GHD, 2014, p. 19). In the economic assessment of the NGP on behalf of Santos,

[5] See Santos (2020, p. 87).
[6] A petajoule is a unit of energy used for expressing the energy content of fuels.

GHD (2016, p. 13) assumed that production would start at 12.8 PJ per annum in 2020 and increase to 74.1 PJ in 2025 from where production would plateau and then eventually tail off, falling to 55 PJ by 2041 (GHD, 2016, p. 19).

By contrast, the most recent estimate by the Commonwealth Department of Industry, Innovation and Science (2019) has put the expected production of the NGP at 36 PJ of gas per annum.

Based on a production capacity of up to 200 TJ of gas per day, it has been claimed that the NGP could supply up to 50 per cent of current gas demand for NSW based on gas consumption of 138 PJ in 2013 (GHD, 2014, p. 19). However, based on current estimated NSW gas consumption of almost 120 PJ in 2019 and reduced gas production of 36 PJ per annum by the Commonwealth Department of Industry, Innovation and Science, this amounts to only around 30 per cent of current NSW gas consumption.

3.2.3 Narrabri Gas Project Production and Delivery Costs

In its 2019 Gas Statement of Opportunities report for eastern and south-eastern Australia, the AEMO (2019) published estimates of natural gas resources and estimates of production costs for both developed and undeveloped gas projects with data sourced from Core Energy & Resources and gas industry participants. This suggested the NGP was a relatively high cost gas development project with an estimated production cost of $7.40 per gigajoule (GJ), ranking 41 out of 51 actual and undeveloped gas projects in terms of production costs.[7]

In the preparation for the 2020 Gas Statement of Opportunities report, the AEMO commissioned Core Energy & Resources (2019, p. 7) to develop an estimate of the cost of production of reserves and contingent resources as at 31 December 2018. While Core Energy & Resources on this occasion did not provide a precise figure for the estimated production cost of gas from the Gunnedah Basin, it provided a range of estimated production costs of between $6.77 to $9.87 per GJ depending on what components were to be included as part of the cost base.

In its 2020 Gas Statement of Opportunities report, the AEMO (2020) provided an updated estimate for production costs at the NGP of $6.40 per GJ based on Santos' P50 production cost at the gate (post processing).[8] This presumably followed representations made by Santos to the AEMO.[9]

The cost of transporting gas by pipeline must also be added to all sources of gas supply. It has previously been estimated that transmission adds $2 per GJ to the cost of delivering gas from the NGP (Forcey & McConnell, 2017, p. 39).

Pipeline infrastructure operator APA (2018, p. 2) is currently progressing preliminary studies for construction of a 460 kilometre gas pipeline – the Western Slopes Pipeline, connecting natural gas from the NGP to the NSW gas transmission network, via the Moomba to Sydney Pipeline. The Core Energy Group (2015, p. 10) has previously suggested an indicative tariff in the order of $0.10 per 100 kilometres of gas transmission pipeline. The current tariff for the Moomba to Sydney Pipeline is $1.13 per GJ (APA Group, 2020). Based on this publicly available information, a transmission charge to deliver gas from the NGP to Sydney is probably somewhere in the order of $1.60 per GJ. Based on the best tariff price for the Moomba to Sydney Pipeline in 2019, this would reduce to $1.20 per GJ.[10]

This suggests the cost of delivering gas from the NGP is likely to be somewhere in the order of $7.60 to $8.40 per GJ to Sydney.

In its economic assessment of the NGP for Santos, GHD (2016, p. 13) commented that:

[7] One petajoule is equal to one million gigajoules.
[8] P50 is defined as 50 per cent of estimates exceed the P50 estimate (Cooper Energy, n.d).
[9] See Santos (2020b, p. 3).
[10] See https://www.accc.gov.au/focus-areas/inquiries-ongoing/gas-inquiry-2017-2025/transportation-prices.

Santos estimated a constant gas price of $8.70 per GJ for the duration of the appraisal period. This gas price estimate includes the implicit costs of transporting gas to the Sydney Moomba pipeline.

The $8.70 per GJ used in the economic assessment is in 2016-17 constant prices; that equates to around $9.21 per GJ at the end of March 2020.[11]

4. Eastern Gas Region

4.1 Overview

The Eastern Gas Region is an interconnected gas grid connecting all of Australia's eastern and southern states and the Australian Capital Territory (ACT) (Australian Energy Market Commission, 2019).[12]

Gas production in the Eastern Gas Region began around 50 years ago (Australian Energy Regulator, 2018, p. 180). Relatively low prices at that time encouraged residential, commercial and industrial customers to use gas. Gas use later expanded into the electricity generation market, because the rapid responsiveness of gas powered turbines make them suitable for peak electricity generation capacity and combined cycle intermediate load generation. Gas powered generation (GPG) also plays an important role in managing fluctuations in intermittent wind and solar generation. More recently, gas has become a major export industry in the Eastern Gas Region, with the launch in early 2015 of the three LNG export projects at Curtis Island in Queensland.

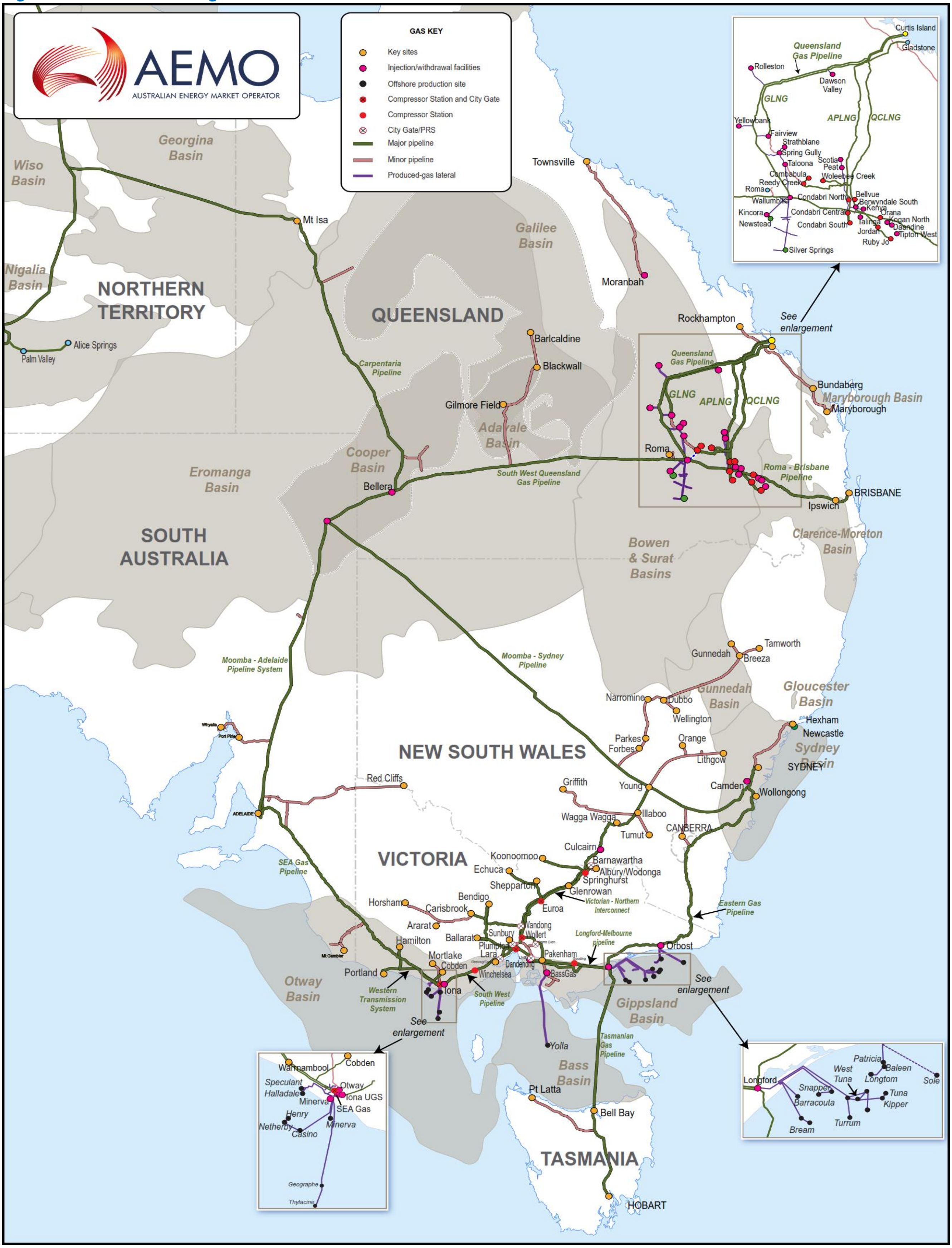
The Eastern Gas Region has evolved from separate state based markets, each served by a single gas basin and a single transmission pipeline (Australian Energy Regulator, 2018, p. 182). Over the past 20 years, new pipeline investment has interconnected these markets, making it possible to transport gas from Queensland to the southern states, and (since key pipelines became bi-directional) vice versa. This interconnected network further expanded with the opening in December 2018 of the 622 kilometre (km) Northern Gas Pipeline linking Tennant Creek in the Northern Territory with Mount Isa in Queensland. For the first time, the new pipeline allows the Eastern Gas Region to source gas from the Bonaparte Basin in the Timor Sea (located between the Northern Territory and East Timor).

NSW, Victoria, Queensland, South Australia, Tasmania and the ACT are now connected through a series of gas transmission pipelines that make up the Eastern Gas Region. This is outlined in Figure 3 below.

[11] Deflated by the all groups consumer price index (Australian Bureau of Statistics, 2020).

[12] For the purposes of this report the term Eastern Gas Region has been adopted as used by the Australian Energy Market Commission. The same region has also been described as the east coast gas market (Australian Competition and Consumer Commission, 2016, p. 1) and the south-eastern Australian gas markets (Australian Energy Market Operator, 2019, p. 13).

Figure 3: Eastern Gas Region



Source: AEMO (2020, p. 35).

Traditionally, the Eastern Gas Region operated in isolation from other gas markets in Australia and overseas because there were no gas exports from or imports to the region (Jacobs SKM, 2014, p. 4). In turn, the Eastern Gas Region had a balanced gas market in which the production of conventional gas largely from the Gippsland Basin in offshore Victoria and the Cooper Basin located in the southwest part of Queensland and north eastern South Australia had been more than sufficient to meet demand (Wood, 2015, p. 2).

Starting in the late 1990's, CSG from Queensland began to enter the Eastern Gas Region (Forcey & McConnell, 2017, p. 10). The onshore Cooper Basin and the offshore Gippsland Basin dominated gas production until 2002, when Cooper Basin production began to decline (Department of Industry and the Bureau of Resources and Energy Economics, 2014, p. 13). In its place, CSG production dramatically increased in the Surat and Bowen Basins in Queensland from 2006.

By 2007, estimated CSG resources had outgrown the requirements of the domestic market and CSG developers sought monetisation of the resource in new, larger markets, the most accessible of which were Asian LNG markets (Jacobs SKM, 2014, p. 11). A number of export projects were proposed between 2007 and 2008 and three projects commenced construction in 2011 and 2012 (Jacobs SKM, 2014, p. 12).

Located in the Eastern Gas Region at Curtis Island near Gladstone in Queensland are three LNG export projects each operating two trains:

- Queensland Curtis Liquid Natural Gas (QCLNG) commenced exporting LNG from its first train in January 2015 and from its second train in July 2015
- Gladstone Liquid Natural Gas (GLNG) commenced exporting LNG from its first train in September 2015 and from its second train in May 2016
- Australian Pacific Liquid Natural Gas (APLNG) commenced exporting from its first train in January 2016 and from its second train in October 2016 (Downey, Thomas, & Stone, 2019; Australian Competition and Consumer Commission, 2016, p. 24).

Train 1 of the QCLNG is jointly owned by multinational energy company Shell (QGC) with a 50 per cent interest and the Chinese National Offshore Oil Corporation (CNOOC) with a 50 per cent interest while train 2 is majority owned by Shell with a 97.5 per cent interest and with a small 2.5 per cent interest owned by Tokyo Gas. Shell acquired QGC (formerly the Queensland Gas Company) in 2016.

GLNG is a joint venture developed and led by Santos (2015a) with a 30 per cent interest, in partnership with Malaysian national oil and gas company PETRONAS with a 27.5 per cent interest, French energy company Total with a 27.5 per cent interest, and the Korea Gas Corporation (KOGAS) from South Korea with a 15 per cent interest.

APLNG is a joint venture operated by US oil and gas company ConocoPhillips with a 37.5 per cent interest, Australian energy company Origin Energy with the 37.5 per cent interest, and China Petrochemical Corporation (Sinopec) with a 25 per cent interest.

Further details on each of the LNG trains at Gladstone are provided in Table 2 below.

Table 2: Gladstone LNG Trains

Project Name	Start Year	Nameplate Capacity (MTPA)*	Owners	Operator
QCLNG Train 1	2015	4.25	Shell (QGC), CNOOC	Shell
QCLNG Train 2	2015	4.25	Shell (QGC), Tokyo Gas	Shell
GLNG Train 1	2015	3.9	Santos, PETRONAS, KOGAS, Total	Santos
GLNG Train 2	2016	3.9	Santos, PETRONAS, KOGAS, Total	Santos
APLNG Train 1	2016	4.5	ConocoPhillips, Origin Energy, Sinopec	ConocoPhillips
APLNG Train 2	2017	4.5	ConocoPhillips, Origin Energy, Sinopec	ConocoPhillips

Sources: International Group of Liquified Natural Gas Importers (2020), International Gas Union (2019), and Origin Energy (Origin Energy Ltd, 2018).
* MTPA – Million tonnes per annum.

4.2 Production

The main production basins within the Eastern Gas Region are the Surat and Bowen Basins in Queensland, the Cooper Basin in South Australia and Queensland and three basins off coastal Victoria, the largest of which is the Gippsland Basin. This is outlined in Table 3 below.

*Table 3: Gas Basins Serving the Eastern Gas Region in 2018-19 Financial Year**

	Gas Production 12 months to June 2019		2P Gas Reserves (August 2019)	
Gas Basins	Petajoules	Share of Eastern Australia Supply (%)	Petajoules	Share of Eastern Australia Supply (%)
Surat–Bowen (Qld)	1,431	75%	34,140	64%
Cooper (SA–Qld)	89	5%	1,040	2%
Gippsland (Vic)	258	13%	2,596	5%
Otway (Vic)	68	4%	667	1%
Bass (Vic)	14	%	175	0%
Sydney and Narrabri (NSW)	5	0%	11	0%
Amadeus (NT)	15	1%	242	0%
Bonaparte (NT)	33	2%	747	1%
Eastern Gas Region Total	**1,913**		53,186	

Source: EnergyQuest, Energy Quarterly, September 2019 as cited by the Australian Energy Regulator (2019).
* Includes production of ethane.

While a majority of Eastern Gas Region's gas reserves are located in the Surat and Bowen Basins in Queensland, those reserves are now largely committed to the LNG export industry (Australian Energy Regulator, 2018, p. 201).

Historically, there have been strong levels of production from the Victorian gas basins – Gippsland, Otway, and Bass (Australian Energy Market Operator, 2019, p. 35). Production in the Gippsland Basin is dominated by the Gippsland Basin Joint Venture (GBJV) composed of Esso (a subsidiary of energy company ExxonMobil) and BHP Billiton. However, several of the Gippsland fields are projected to reach their end of life between mid-2023 and mid-2024, and all currently producing fields in the Otway Basin will cease production unless anticipated gas field development or plant modification projects proceed (Australian Energy Market Operator, 2020, p. 8).

The Cooper Basin has been an important source of supply for the South Australian market via the Moomba to Adelaide Pipeline System (MAPs), and for the NSW market via the Moomba to Sydney Pipeline (MSP) (Australian Competition and Consumer Commission, 2016, p. 29). The Cooper Basin is a mature conventional gas production area, having been in production for around 50 years (Oakley Greenwood, 2017, p. 40). The Cooper Basin's peak gas production occurred around 2000-2002 after which it entered a tail gas phase where new deliverability projects are unable to arrest the natural decline in production due to a reduction in available 2P gas reserves (Oakley Greenwood, 2017, p. 41).

Santos is the major producer in the Cooper Basin, leading the South Australian Cooper Basin joint ventures and the South West Queensland Cooper Basin joint ventures. The Santos-led joint ventures, alongside Beach Petroleum as the other major participant, control most of the gas reserves in the Cooper Basin (Australian Energy Regulator, 2018, p. 188).

The bulk of production from the Cooper Basin has now been committed to the GLNG project (Australian Competition and Consumer Commission, 2017, p. 29). Santos entered an agreement in 2010 to supply GLNG with 750 PJ of gas over 15 years, which accelerated the depletion of the basin's conventional gas reserves (Australian Energy Regulator, 2018, p. 188).

NSW has only been a small producer of gas and has been reliant on importing gas from Queensland or South Australian Cooper Basin producers through Moomba via the MSP or from Victoria through the Eastern Gas Pipeline (EGP) (Oakley Greenwood, 2017, p. 33). Historically, around 40 per cent of NSW's gas has come from the Cooper Basin, around 55 per cent has come from Victoria and around 5 per cent has come from NSW (GHD, 2017, p. 3.2).

The most significant production of natural gas in NSW comes from the Camden Gas Project operated by AGL. The Camden Gas Project has been in operation since 2001 and supplies around 5 per cent of NSW demand (AGL Energy Limited, 2017a). The Project produces CSG throughout the Macarthur region of NSW. The field is located around 65 km south-west of Sydney and operates within the Camden, Campbelltown and Wollondilly local government areas.

The Camden Gas Project originally had 144 wells, 86 of which are currently in production (AGL Energy Limited, 2019). The other major element of the Camden Gas Project is the Rosalind Park Gas Plant in Menangle, where natural gas is collected via low pressure underground gathering lines, compressed, dried and made ready for use by households and businesses, and transmitted into the greater Sydney natural gas network (AGL Energy Limited, 2017a). In February 2016, AGL announced that it will progressively decommission wells and rehabilitate sites at the Camden Gas Project prior to ceasing production in 2023.

As discussed above, a small amount of gas produced by NGP exploration wells is being used to power the Wilga Park Power Station.

4.3 Domestic Consumption

Demand for gas in the Eastern Gas Region has evolved in recent years, from mainly serving domestic consumers, to now servicing a growing LNG export market (Australian Energy Market Operator, 2019, p. 17). Consumption of natural gas from the LNG export projects now dwarfs that for domestic users (Bethune & Wilkinson, 2019, p. 520). In 2019 LNG exports accounted for almost 69 per cent of natural gas consumption in the Eastern Gas Region (Australian Energy Market Operator, 2020).

Gas is used in different ways across the Eastern Gas Region. In Victoria, gas consumption is dominated by the residential/commercial sector with heating representing a significant proportion of usage, but in Queensland, this sector has a very small proportion of regional gas consumption, with markedly less gas used for heating (Australian Energy Market Operator, 2019, p. 19). Gas consumption in Queensland is dominated by the LNG export sector.

Table 4 below provides the estimated gas consumption by region and purpose within the Eastern Gas Region during 2019.

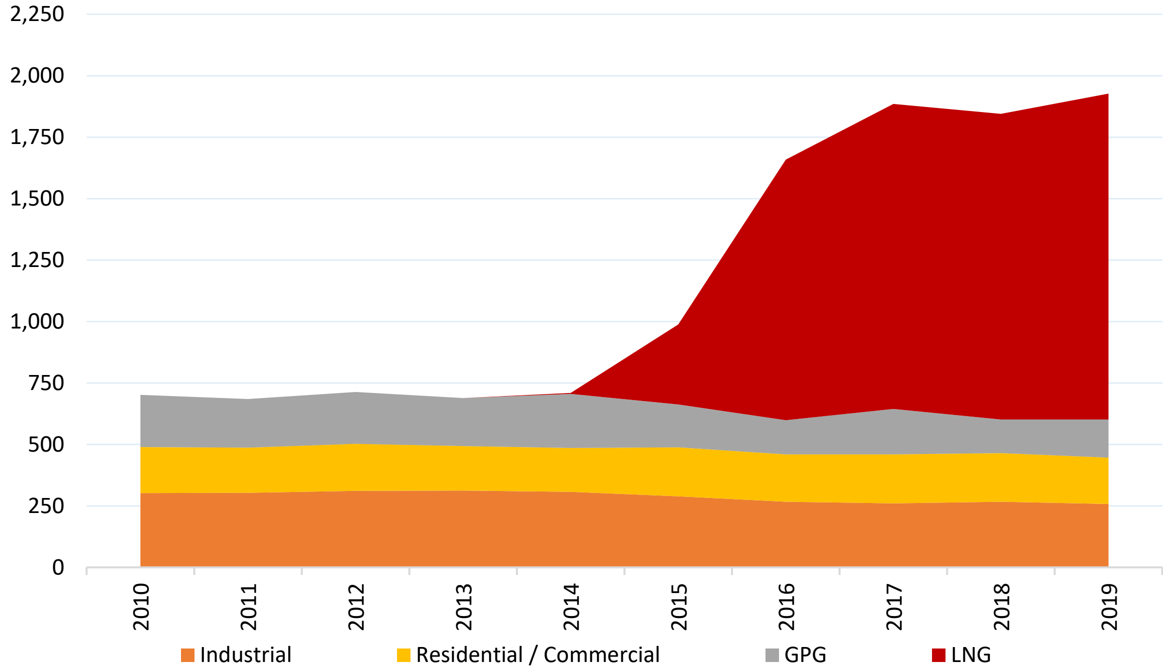
Table 4: Estimated Regional Consumption of Gas within the Eastern Gas Region by Sector – 2019 Calendar Year

Region	Residential/ Commercial (%)	Industrial (%)	Gas-Powered Electricity Generation (%)	LNG Exports (%)	Regional Gas Consumption (PJ)
Queensland	0.4%	7.1%	2.4%	90.1%	1,380 PJ
New South Wales	39.9%	46.2%	13.9%	0%	116 PJ
South Australia	11.0%	23.7%	65.3%	0%	93 PJ
Tasmania	7.5%	48.6%	43.9%	0%	10 PJ
Victoria	55.3%	29.3%	15.3%	0%	212 PJ
Total	9.9%	13.2%	8.1%	68.8%	1,811 PJ

Source: AEMO (2020).

Actual consumption of natural gas is provided below in Figure 4, which outlines the significant ratcheting up of gas consumption by the LNG export projects since 2014.

Figure 4: Eastern Gas Region Natural Gas Consumption – 2010 to 2019 (PJ)



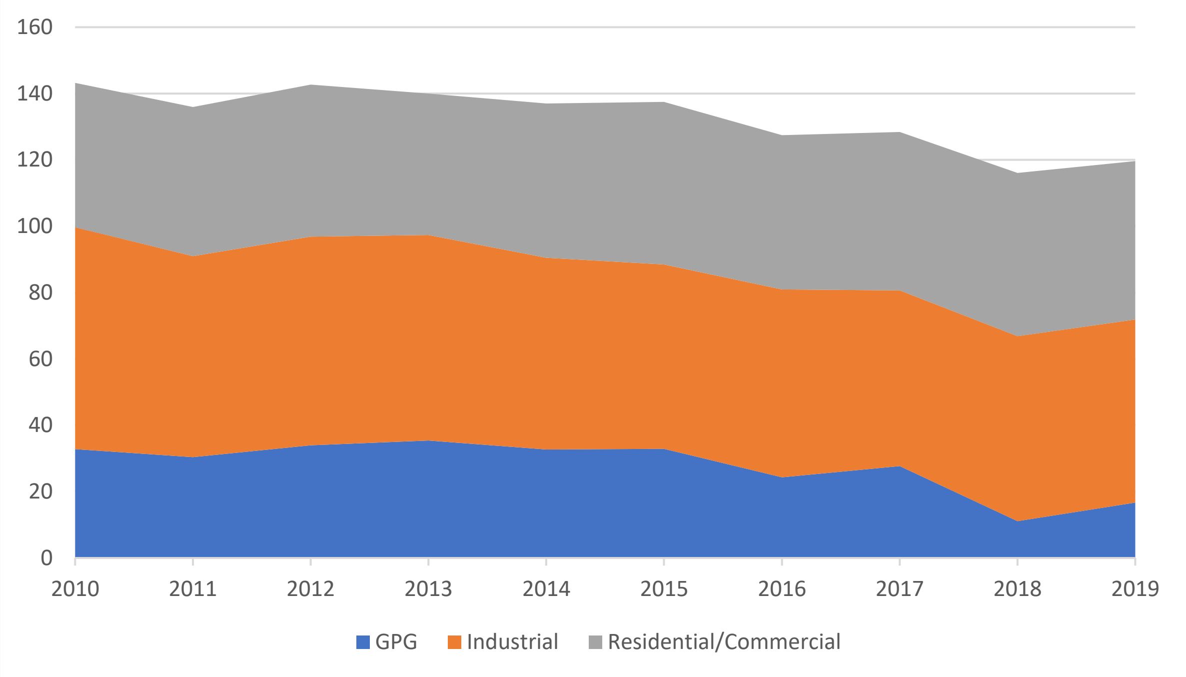
Source: AEMO (2020).

NSW consumption of gas has been in decline in trend terms since 2010 driven by falling industrial consumption as well as a marked drop off in consumption for GPG since 2014, slightly offset by increased commercial and residential consumption.

Consumption by GPG has been trending downwards since 2014 as new renewable energy has entered the National Electricity Market (Australian Energy Market Operator, 2020, p. 64). However, this downward trend in GPG was not observed in 2019, as the Mount Piper Power Station experienced coal quality issues, which drove increased GPG to replace the lost generation, and NSW also provided some support for the loss of Loy Yang A2 in Victoria across 2019.

Declining NSW consumption of gas is outlined in Figure 5 below.

Figure 5: New South Wales Natural Gas Consumption by Sector – 2010 to 2019 (PJ)



Source: AEMO (2020).

4.4 Demand and Supply Balance

Prior to recent economic disruptions caused by the COVID-19 coronavirus outbreak, numerous parties were predicting gas supply shortfalls in the Eastern Gas Region in the foreseeable future. According to the AEMO (2020, p. 9):

> *Gas production from only existing and committed gas developments is forecast to provide adequate supply to meet gas demand until between 2023 and 2025 depending on scenario, provided cargoes of export LNG above contracted levels are diverted to meet domestic demand if needed. Beyond this point, existing and committed southern field projects are forecast to be insufficient to meet southern demand, and major southbound pipeline infrastructure upgrades would be required to deliver more gas from northern to southern states, particularly during winter peak days.*

According to the Australian Competition and Consumer Commission (ACCC) (2020, pp. 1-2):

> *The long term supply outlook for the East Coast Gas Market from 2021–2031 remains uncertain. The Southern States risk facing a shortfall in the medium-term unless:*
>
> *• more exploration and development occurs in the south to compensate for declining ex-Longford production*
>
> *• more investment occurs in north-south transportation infrastructure to enable greater volumes of gas from Queensland or the Northern Territory to flow south, and*
>
> *• one or more LNG import terminals are developed.*

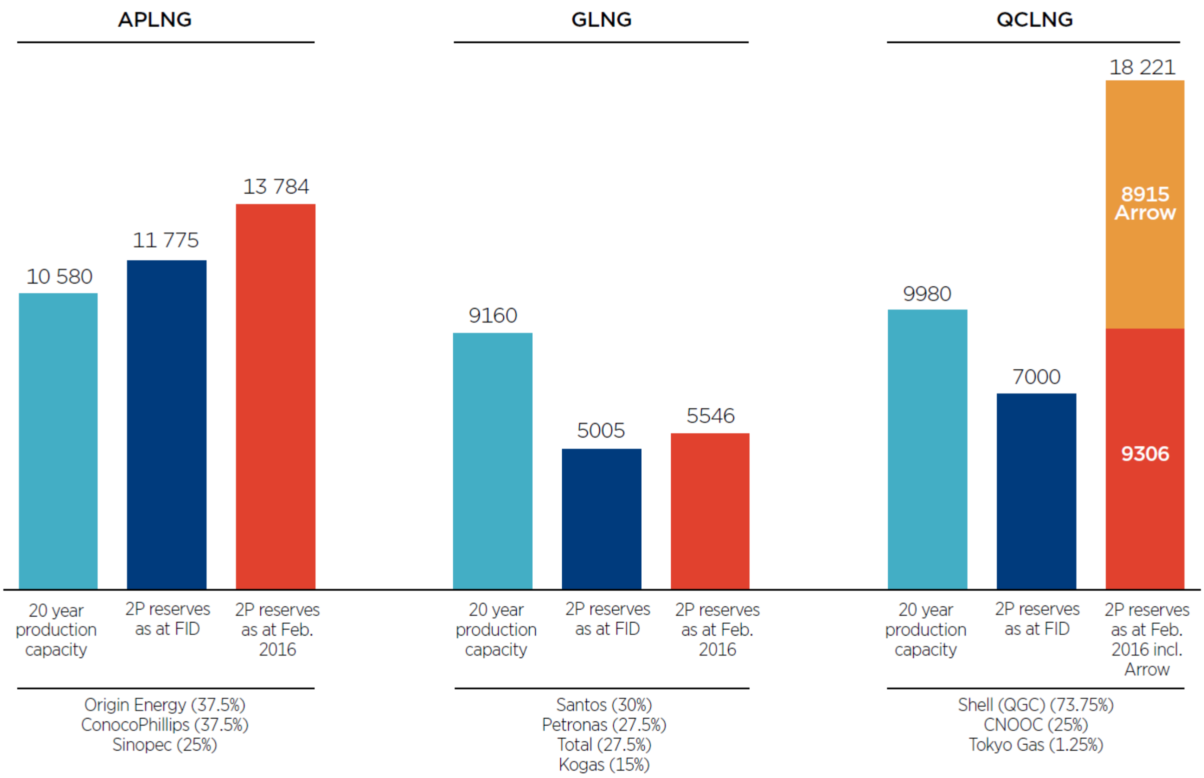
Similarly, Dr Graeme Bethune and Rick Wilkinson (2019, p. 521) of energy advisory firm EnergyQuest have predicted a looming gas shortfall:

Gas supply in the east coast is struggling to meet demand and will fall short by 2026 without a major shake-up or break through, such as a bold new gas exploration success, importing LNG or demand destruction.

The supply of natural gas in the Eastern Gas Region has tightened since the Queensland LNG export projects started to draw on reserves (Australian Energy Regulator, 2017, p. 8).

Decisions made by one of the Queensland LNG export projects, in particular, stand out as the root cause for any future impending natural gas shortfalls in the Eastern Gas Region. While APLNG and QCLNG primarily expected to meet their LNG export commitments through the development of gas resources owned by them, the Santos-led GLNG always expected to source gas from other producers in the Eastern Gas Region to supplement its CSG reserves (Australian Competition and Consumer Commission, 2016, p. 28). This is reflected in Figure 6 below which shows the total production capacity of the two GLNG trains significantly exceeded the volume of gas that GLNG could produce from its 2P CSG reserves at the time the project was sanctioned.

Figure 6: Expected LNG Plant Production Capacity and 2P Reserves of the Queensland LNG Projects (PJ)



Source: ACCC (2016, p. 28).

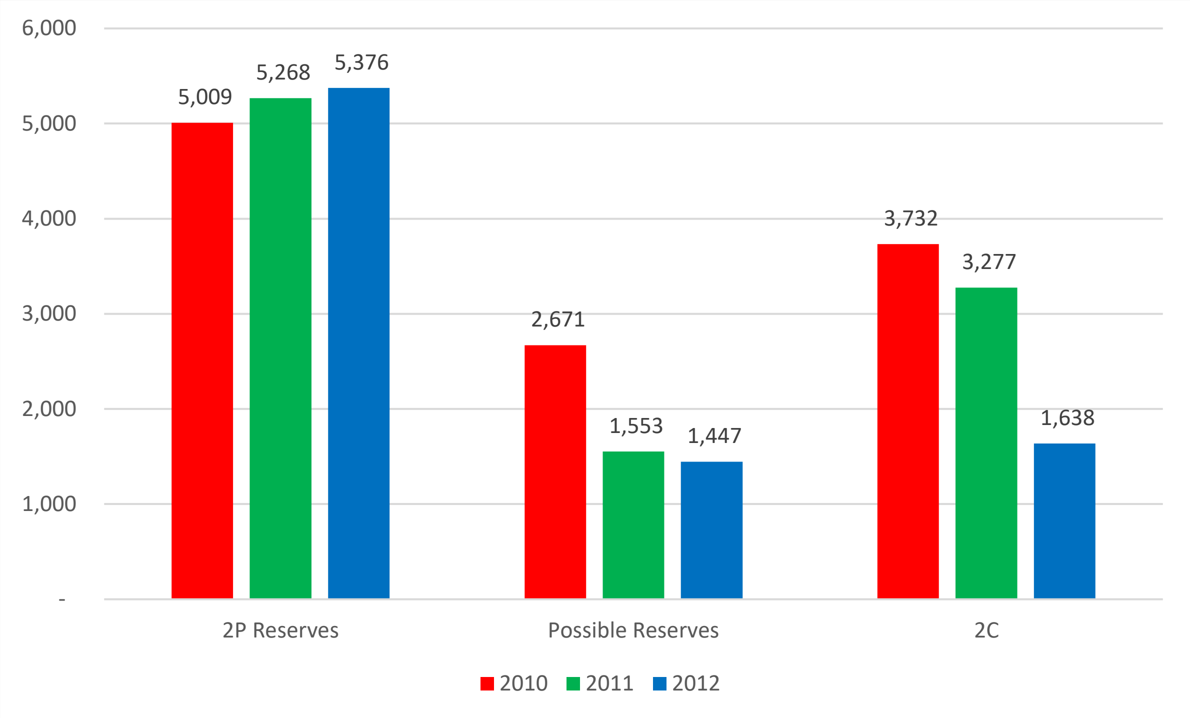
At the time the final investment decision was made to proceed with the GLNG project, it had only 5,005 PJ of 2P reserves (Santos Ltd, 2011, p. 10). However, Santos claimed that GLNG had ultimate 2P CSG reserves maturation of 9,848 PJ from existing acreage based on analysis by petroleum consultants Netherland, Sewell & Associates who contended that continued development and appraisal drilling in the GLNG dedicated areas had a reasonable likelihood of extending the 2P reserves area into most of the regions then categorised as possible reserves or 2C contingent resources.[13]

However, the contention by Netherland, Sewell & Associates that possible reserves and contingent resources would eventually be converted over to 2P reserves became increasingly difficult to justify

[13] Possible reserves are those additional reserves which analysis of geoscience and engineering data suggest are less likely to be recoverable than probable reserves (Society of Petroleum Engineers, 2017, p. 13).

in the face of GLNG reserve updates provided by Santos (2013). While GLNG actual 2P reserves did increase, possible reserves and contingent resources slumped with each further gas reserve update. This is shown in Figure 7 below.

Figure 7: Proven and Probable Reserves (2P), Possible Reserves and Contingent Resources (2C) for GLNG (PJ) – 2010 to 2012 (year end to December)



Source: Santos (2013).

Concerns over the lack of reserves for the Santos-led GLNG project have been longstanding, with Mathew Murphy (2010) reporting in *The Sydney Morning Herald* in September 2010 that GLNG did not yet have "adequate reserves to support it." Journalist Paddy Manning (2014) reported in February 2014:

> *Santos is in a bind. Its $20 billion-plus Gladstone LNG project is widely considered to be short of gas, with analysts scratching their heads at a lack of reserve growth and further contingent resource downgrades in its latest accounts.*

In late 2016, Geoscience Australia (2016, p. 14) reported to the Council of Australian Governments (COAG) Energy Council in relation to the three LNG export projects that:

> *APLNG and QCLNG appear best placed to utilise their native gas volumes (i.e. sourced from within their tenure holdings) to fulfil contractual requirements. Conversely, current reserve and resource figures for the GLNG project show a potential native gas shortfall.*

When asked about constructing two trains for the GLNG project in late August 2010, the then Santos Chief Executive Officer and Managing Director, David Knox, commented:

> *The key issue you've got to be absolutely confident of when you sanction trains is that you've got the full gas supply to meet your contractual obligations that you've signed up with a buyer.*
>
> *Now you should have confidence that we will sanction the second train because we will have signed up with the buyers to supply gas from that second train. In*

> *order to do it, we need to have absolute confidence ourselves that we've got all the molecules in order to fill that second train. (CQ Transcriptions, LLC., 2010)*

Then in late October 2010 Santos (2010) announced that it had reached an agreement to supply 750 PJ of gas to the GLNG project, with existing uncontracted Cooper Basin 2P reserves being the primary supply source. The agreement was conditional on the final investment decision for the GLNG second train. As a consequence of this agreement, the conventional gas reserves in the Cooper Basin will be depleted sooner than they otherwise would have been (Australian Competition and Consumer Commission, 2016, p. 60). Jim Snow (2017), Executive Director of energy consultants Oakley Greenwood, has described this agreement as the "smoking gun" for impending natural gas shortfalls in the Eastern Gas Region.

In 2016, the ACCC (2016, p. 24) observed the Santos-led GLNG had been purchasing substantial volumes of gas in the domestic market over the previous five years to supplement production from its inadequate reserves. In December 2016 Santos (2016b) reported on the third party gas supply contracts that GLNG had entered, a summary of which is presented below in Table 5.

Table 5: GLNG Third Party Gas Supply Agreements

Supplier	Quantity PJ	From	Term
Santos	750	2015	15 years
Origin	365	2015	10 years
Origin	194	2016	5 years
Other Suppliers	85	2015 2016	7 years 21 Months
Meridian JV	445	2016	20 years
AGL	254	2017	11 years
Senex	340	2018	20 years
Combabula	52	2015	20 years
Spring Gully	17	2015	20 years
Uncommitted Combabula / Spring Gully / Ramyard	321	2015	15 years +

Source: Santos (2016b, p. 64).

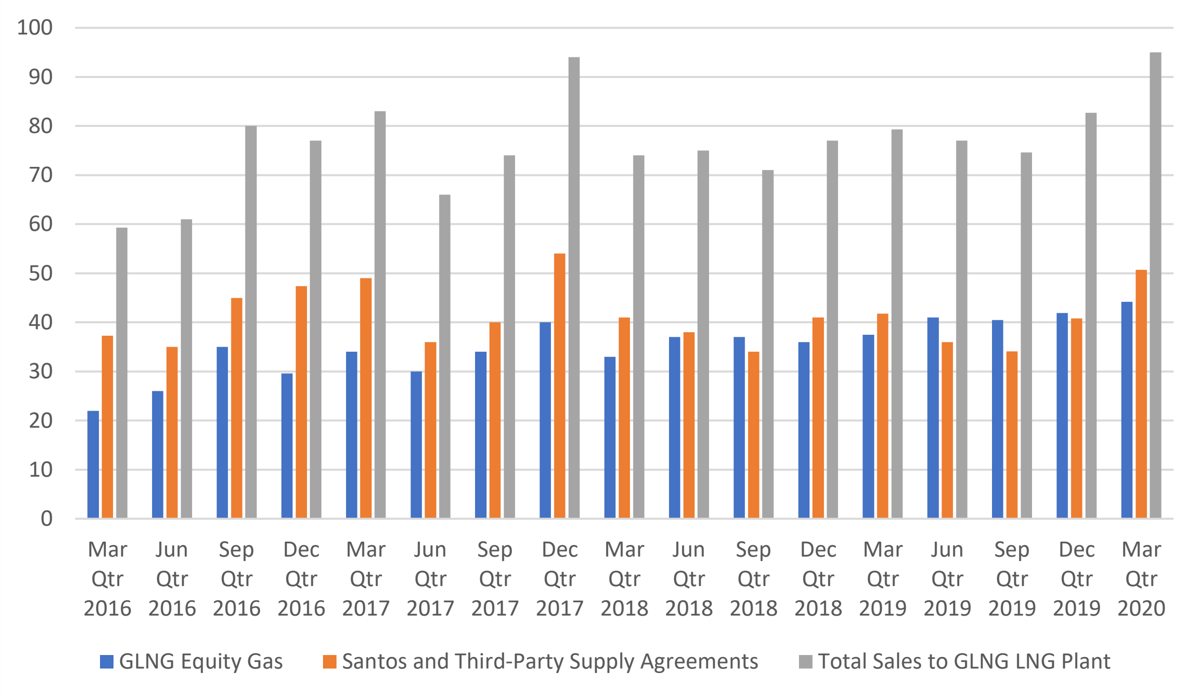
The available evidence suggests Santos did not in fact possess all the *molecules* it required to fill the second train for the GLNG project as suggested by its former Managing Director and Chief Executive Officer. Furthermore, the number of third party gas supply agreements entered into by GLNG commencing in 2010 also directly repudiates claims made by Santos (2009, p. 6.15.11) in the GLNG *Environmental Impact Statement* in 2009:

> ***The project may initially supply domestic gas markets, but it is not diverting gas from local markets to export markets.*** *The project's supply of gas to the domestic market is uncertain at this stage. Options to manage ramp up gas and any gas that is surplus to the requirements of the LNG facility include a range of commercial and technical possibilities. Therefore the project has no direct implications for domestic gas prices.* ***The gas to supply the LNG facility will come from newly developed CSG fields.*** *The amount of gas is very small relative to the*

identified conventional and CSG fields reserves available to supply the Australia east gas fields. ***It is therefore unlikely to contribute to a future shortage of gas in the domestic market.***[14]

As a matter of fact the Santos-led GLNG project has diverted natural gas from domestic users to export markets, as it has not exclusively relied upon newly developed CSG fields for its gas supply, and it has been the major contributor towards any impending natural gas shortfalls within the Eastern Gas Region. Only in four quarters out of seventeen has GLNG sourced more than 50 per cent of the gas supplied to its LNG plant from its own sources, with the bulk of gas generally supplied by Santos and through other third-party agreements. This is outlined in Figure 8 below.

Figure 8: Sales of Gas to GLNG LNG Plant – March Quarter 2016 to March Quarter 2020 (PJ)



Source: Santos (2020a).

In an article entitled *Why Santos owns the gas crisis*, *The Australian Financial Review* columnist Matthew Stevens (2017) put responsibility for any impending natural gas shortfalls within the Eastern Gas Region squarely at the feet of Santos and the GLNG project:

> *The facts of the role that Santos and its partners in the GLNG project have played in delivering the nation to gas shortage are well appreciated and incontrovertible.*
>
> *Despite some internal debate, Team Santos decided to proceed with the construction of a second train at its Curtis Island liquefied natural gas plant.*
>
> *That debate was triggered by the fact that Santos did not have enough gas to justify that investment. But, because it found customers enough prepared to sign up to long-term contracts, the GLNG partnership took the risk that the oil price would hold at better than $US70 a barrel and thus oil-linked LNG prices would ensure the venture would make money by filling its freezer with other people's gas.*
>
> *Then the oil price went bust and with it went that investment paradigm.*

---

[14] Emphasis not in the original document.

Similarly, business journalist for *The Australian* newspaper Matt Chambers (2017) wrote:

> *Rightly or wrongly, GLNG and its past investment decisions are being painted by many as the major culprit in the east coast gas crisis.*
>
> *…*
>
> *GLNG is in its gas-short position after it approved two production trains at Gladstone in 2011 without having enough gas reserves to supply them.*

Apparently not willing to let a good crisis go to waste, Santos has used the pretext of looming gas supply shortages in NSW as a fulcrum to garner regulatory approval for its NGP, without acknowledging the central role it played in creating the circumstances that it now claims the NGP will address. The Preliminary Environmental Assessment for the NGP in 2014 stated:

> *The anticipation of restricted gas supply to NSW heightens the need for a local gas resource for NSW to provide increased security for the current demand and to meet the projected future demand. The proposed development would provide infrastructure to help facilitate overcoming these predicted challenges and thereby meet projected demand for eastern states over the next decades. (GHD, 2014, pp. 19-20)*
>
> *The do nothing option would result in the absence of potentially 50% of NSW gas requirements being* available for supply to the NSW gas market. *(GHD, 2014, p. 20)*

Similarly, in early 2015 Santos (2015d, pp. 12-13) commented on the prospect of looming gas supply shortages in NSW in its submission to the NSW Legislative Council Select Committee on the Supply and Cost of Gas and Liquid Fuels in following terms:

> *It is now widely accepted that NSW may have gas shortages and challenges after 2016 when the existing supply contracts with NSW gas retailers from the Cooper Basin come to an end ... there will be a significant shortfall in gas for NSW customers as contracts roll-off and instead the gas from the Cooper Basin and Queensland is contracted to supply export customers via the Gladstone LNG projects or domestic customers in Queensland and SA.*
>
> *…*
>
> *As a result after 2016, NSW will be predominately supplied, as much as is possible, from Victoria. The supply will be impeded by transmission constraints, with gas flowing up the Eastern Gas Pipeline (EGP) as well as the NSW-Victoria interconnector ... This is despite adequate Moomba-Sydney Pipeline (MSP) capacity being available for supply from the Cooper Basin and/or Queensland into NSW as that gas is very unlikely to be available.*
>
> *From 2016 NSW will increasingly need to compete for gas supplies with others in the Eastern Gas Market. If NSW gas resources are not developed it is unclear where the additional gas required to meet static demand will come from, notwithstanding any growth in demand.*

In 2017 the Environment Impact Statement for the NGP also focused on impending gas shortages in NSW in support of the project:

> *From 2017 a major shift will occur when all three liquefied natural gas (LNG) facilities in Queensland will reach more stable production levels. The majority of the gas that was previously contracted from the Cooper Basin will no longer be available to supply NSW, as it has been contracted from 2016 to meet some of the supply requirement of these Queensland natural gas facilities.*
>
> *The absence of alternative sources of gas going forward, coupled with the diversion of gas from the Cooper Basin to fulfil LNG export contracts, means NSW will require the vast majority of its gas to be supplied from Victoria. This reliance on a single supply source may pose significant security of supply risk in the event of an interruption, as occurred in 1998 when there was an event at the Longford gas plant in Victoria that resulted in severe gas shortages across the state. (GHD, 2017, pp. ES.5-ES.6)*

Santos has also acknowledged that the company's actions have been blamed for any impending gas shortages in the Eastern Gas Region, with current Santos Chief Executive Kevin Gallagher (2019, p. 4) telling the 2019 APPEA conference in late May 2019:

> *It has been said that not all six LNG trains on Curtis Island should have proceeded and that Santos should not have built the second of its two trains.*
>
> *That second train has sometimes been blamed for the tight east coast domestic gas market today.*

4.4.1 Future Supply Options

If there is an impending shortfall of gas in the Eastern Gas Region, increased gas supply and exports from Queensland could potentially make up some of the shortfall in the southern states (Bethune & Wilkinson, 2019, p. 521). However, there are infrastructure limitations on how much gas can be exported from Queensland to the southern states. The existing pipeline infrastructure cannot move more than 140 PJ per annum without more investment.

Additional investment in pipeline infrastructure will face a number of challenges (Bethune & Wilkinson, 2019, p. 521). First, there are no low cost 2P gas reserves left available to supply a pipeline long-term for the southern states. Second, while CSG from the Surat and Bowen Basins can meet some of the southern shortfall, the period before the decline of the CSG fields is only a few years away and not sufficient to underwrite further pipeline investments unless gas already committed to the LNG export projects is redirected toward domestic users (Bethune & Wilkinson, 2019, p. 521). Essentially, CSG reserves developed for export in Queensland are not sufficient to supply both the export market as well as the entire Eastern Gas Region (Collins, Cockerill, & Rasheed, 2019, p. 542).

While there has been a response from gas producers in the form of new gas developments, the currently approved projects and near term proposals are mostly small in scale and may not be able to fill the gap being created by declining reserves in large historic gas fields (Collins, Cockerill, & Rasheed, 2019, p. 542).

The AEMO (2020, p. 3) has warned in relation to gas supply for southern states that:

> *Unless additional southern supply sources are developed, LNG import terminals are progressed, or pipeline limitations are addressed, gas supply restrictions and curtailment of gas-powered generation (GPG) for the National Electricity Market (NEM) may be necessary on peak winter days in southern states from 2024.*

The AEMO (2020, p. 52) has suggested that an LNG terminal would delay future gas supply shortages for the southern states longer than the development of the NGP. An LNG import terminal would also allow for much greater flexibility in terms of being capable of ramping up supply in order to meet seasonal demand fluctuations than the NGP, especially during the winter months when the consumption of gas rises for heating.

4.4.2 NSW Demand and Supply Balance in the Context of the Narrabri Gas Project

NSW is currently heavily dependent on imports from other states for its gas supplies.

As previously discussed, the only indigenous gas production in NSW is the Camden Gas Project operated by AGL that currently supplies around 5 per cent of NSW demand. However, the Camden Gas Project is due to cease production in 2023.

In addition, the gas fields that have traditionally supplied the NSW market, primarily the Gippsland Basin in Victoria and the Cooper Basin in South Australia and Queensland, are in natural decline. Furthermore, most of the remaining future gas reserves in the Cooper Basin have been contracted to GLNG. In addition, CSG reserves developed by LNG export projects in Queensland are not sufficient to supply both the export market as well as the entire Eastern Gas Region (Collins, Cockerill, & Rasheed, 2019, p. 542).

Under these circumstances, the development of the NGP would provide additional gas supply for NSW. In this respect, Santos (2015d) is arguably broadly correct in its contention:

> *The Narrabri Gas Project could be a significant contributor to NSW's emerging predicament, should the project proceed. The project can supply up to 50 per cent of NSW's daily gas requirements via a dedicated pipeline heading south.*

However, the NGP will only provide a partial solution to any impending gas shortfalls in NSW at best. NSW will still need to find additional sources of supply, either from new projects from domestic sources within the Eastern Gas Region or from LNG imports to supplement any supplies it may receive from the NGP in the event it proceeds.

4.5 Prices

The Eastern Gas Region was historically characterised by long-term gas supply agreements (GSAs) where wholesale gas buyers typically had few difficulties renegotiating their GSAs when they expired (Australian Competition and Consumer Commission, 2016, p. 29). Gas supplied to industrial users under long-term GSAs was historically priced using a cost-plus formula, in which the contract price paid for gas by users was calculated based on the cost of production plus a margin and escalated with inflation. Non-price terms such as the duration of GSAs, price review mechanisms, quantities (including flexibility on delivered quantities) and delivery locations were typically rolled over from one GSA to another and remained relatively stable.

Aside from GSAs, wholesale gas within the Eastern Gas Region can also now be traded on a short-term basis through the Victorian declared wholesale gas market (DWGM), the Short Term Trading Market (STTM) operating in Sydney, Adelaide and Brisbane, and the Wallumbilla Gas Supply Hub (GSH) west of Brisbane and the Moomba GSH.

From the late 1970s until 2010, domestic gas production in the Eastern Gas Region had taken place in an environment of relatively low gas prices (Department of Industry and the Bureau of Resources and Energy Economics, 2014, p. 13). Until approximately 2010, new gas contracts were available in eastern Australia at price levels that had remained steady in real terms over the previous decade or longer (Jacobs SKM, 2014, p. 11). Domestic gas contract prices historically averaged around $3-$4 per GJ (Australian Energy Regulator, 2018, p. 208).

The development of the three LNG export projects precipitated uncertainty about the future supply-demand balance within the Eastern Gas Region (Australian Competition and Consumer Commission, 2016, p. 24). According to the ACCC (2016, p. 24), this uncertainty was exacerbated by the Santos-led

GLNG purchasing substantial volumes of gas in the domestic market to supplement production from its inadequate reserves, with a large portion of this gas coming from the Santos dominated Cooper Basin that historically had supplied NSW and South Australia. In turn, wholesale gas prices offered to domestic users began to rise.

Where gas contracts had traditionally locked in prices and other terms and conditions for several years (Australian Energy Regulator, 2018, p. 208), the industry has more recently shifted towards shorter term contracts with review provisions. Coinciding with the growing uncertainty regarding future gas availability, many long-term domestic GSAs were set to expire over the course of 2016 through to 2018 (Australian Competition and Consumer Commission, 2016, p. 24). Anticipating potential gas supply challenges, a number of industrial gas users approached gas suppliers in the period from about 2012 to the end of 2014 to secure gas for supply in 2016 and beyond. Many quickly found that they had fewer options for gas supply than previously and some users encountered difficulties getting any offers at all for supply in certain periods. Where offers were made, they were often at substantially higher prices and on less flexible terms than in the past.

Jacobs SKM (2014, p. iii) reported in April 2014 in relation to new GSAs that:

- Prices have escalated since before 2010 and cover a wide range from approximately $5.50/GJ to $10.00/GJ
- Prices in Queensland appear to have escalated further in 2013 relative to 2010-2012 as more third-party gas has been purchased by the LNG export projects
- Prices for gas in southern states, sourced from the Gippsland Basin Joint Venture (GBJV), are lower than those in Queensland but may be set to escalate to parity levels.

With the commencement of LNG exports in early 2015, the Eastern Gas Region was transformed from a captive domestic “buyer's” market to an internationally-linked “seller's” market (Forcey & McConnell, 2017, p. 12). In turn, the development of the three LNG export projects in Queensland exposed domestic gas users to international gas prices for the first time (Australian Competition and Consumer Commission, 2016, p. 22).

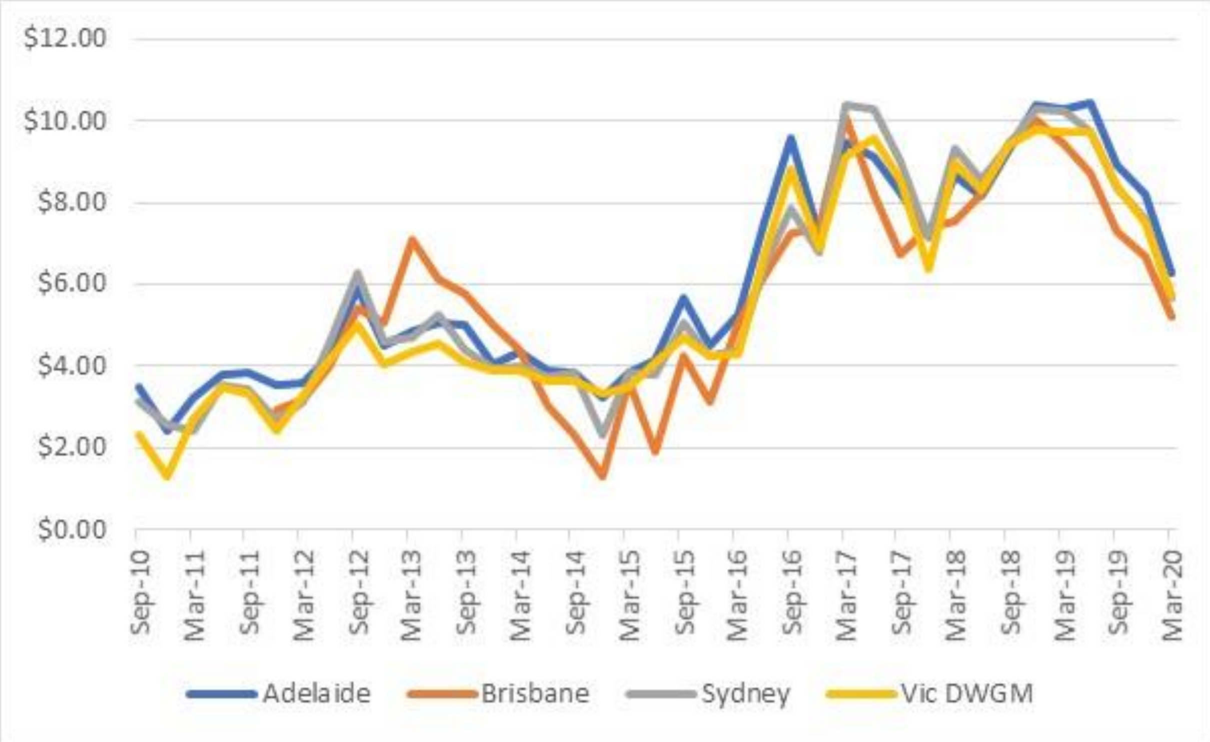
GSAs signed around 2015 were often for around $6 per GJ; in late 2016 prices offered to industrial customers began to rise rapidly, peaking above $20 per GJ in the first half of 2017 (The Australian Industry Group, 2018, p. 9). However, prices have since abated from these more extreme levels. By August 2018, most offers were priced at, or above, the mid-$10 per GJ level (Australian Competition and Consumer Commission, 2018a, p. 12). The latest available data shows that the bulk of commercial and industrial gas users will be paying mostly within a range of around $9–12/GJ (Australian Competition and Consumer Commission, 2020, p. 1).

Any competitive tensions in the supply of gas for the Eastern Gas Region that may have previously existed would have evaporated when Santos decided to prioritise and redirect the bulk of its Cooper Basin gas production to GLNG and the LNG export market. According to the ACCC (2016, p. 42):

> *… there has been a significant change in the pricing dynamics in the southern states as a result of the decisions made by the Cooper Basin producers, particularly Santos, to commit significant volumes of gas produced in the Cooper Basin to the LNG projects. The Cooper Basin producers historically played a critical role in competing with the GBJV for market share in the southern states. The reduction in the diversity of gas suppliers in the southern states has substantially strengthened the competitive position of the GBJV and has severely undermined the bargaining position of domestic users in negotiation with the GBJV.*

Wholesale gas price rose from historical values of around $3 per GJ to around $10 per GJ by the June quarter 2019 since the three LNG export projects commenced operations in 2015 and Santos prioritised Cooper Basin production to GLNG. Since then, wholesale gas prices have fallen dramatically, exacerbated recently by the COVID-19 coronavirus outbreak. This is shown below in Figure 9 from the Victorian DWGM and the STTM prices in Sydney, Adelaide and Brisbane.

Figure 9: Average Quarterly Prices for the Imbalance Price for the Victorian Declared Wholesale Gas Market and the Short Term Trading Market Prices for Sydney, Adelaide and Brisbane – September Quarter 2010 to March Quarter 2020 ($ per GJ)



Source: Australian Energy Regulator.

With the commencement of the three LNG export projects, gas producers in the Eastern Gas Region now have an export option for their gas while any of the LNG projects require additional gas to meet their contractual export commitments or fill spare production capacity in their trains (Australian Competition and Consumer Commission, 2016, p. 45). This means that domestic gas users in Queensland will have to directly compete with the LNG projects for any gas that is available for supply in Queensland. Similarly, domestic gas producers are likely to be seeking a price that is commensurate with an amount the LNG projects are willing to pay.

The ACCC (2016, p. 45) has suggested that future domestic gas prices in Queensland will typically be influenced by LNG netback prices, which represent the maximum amounts the LNG projects would be willing to pay to purchase third party gas. LNG netback prices represent the export parity price a domestic gas producer would expect to receive from exporting its gas rather than selling it domestically (Australian Energy Regulator, 2018, p. 210). It is calculated as the price for selling LNG (based on Asian spot prices) and subtracting or 'netting back' the costs of converting gas to LNG and shipping it overseas. The cost includes liquefaction, shipping to Asia and regasification in Asia. If LNG netback prices exceed domestic prices, it becomes more profitable to export gas than to sell it locally.

While the option for southern gas producers of selling gas to the LNG export projects remains, the price they can achieve from selling to the LNG export projects represents the floor price in their negotiations with domestic gas buyers (Australian Competition and Consumer Commission, 2016, p. 51). Given the lack of alternative southern producers that are able to offer significant volumes of uncontracted gas, a buyer's alternative in the negotiation with the GBJV is likely to be uncontracted gas available in Queensland. Given the Queensland market is now being driven by the LNG fundamentals, southern buyers would have to offer the LNG netback price at Wallumbilla to northern producers to bid this gas away from the LNG projects and then transport this gas to their location. This price generally represents the ceiling in a buyer's negotiations with the GBJV. In this regard, the ACCC (2019, p. 41) has noted the Victorian gas producers (Gippsland, Bass and Otway basins) received higher prices at the end of 2018 than other gas producers in the Eastern Gas Region.

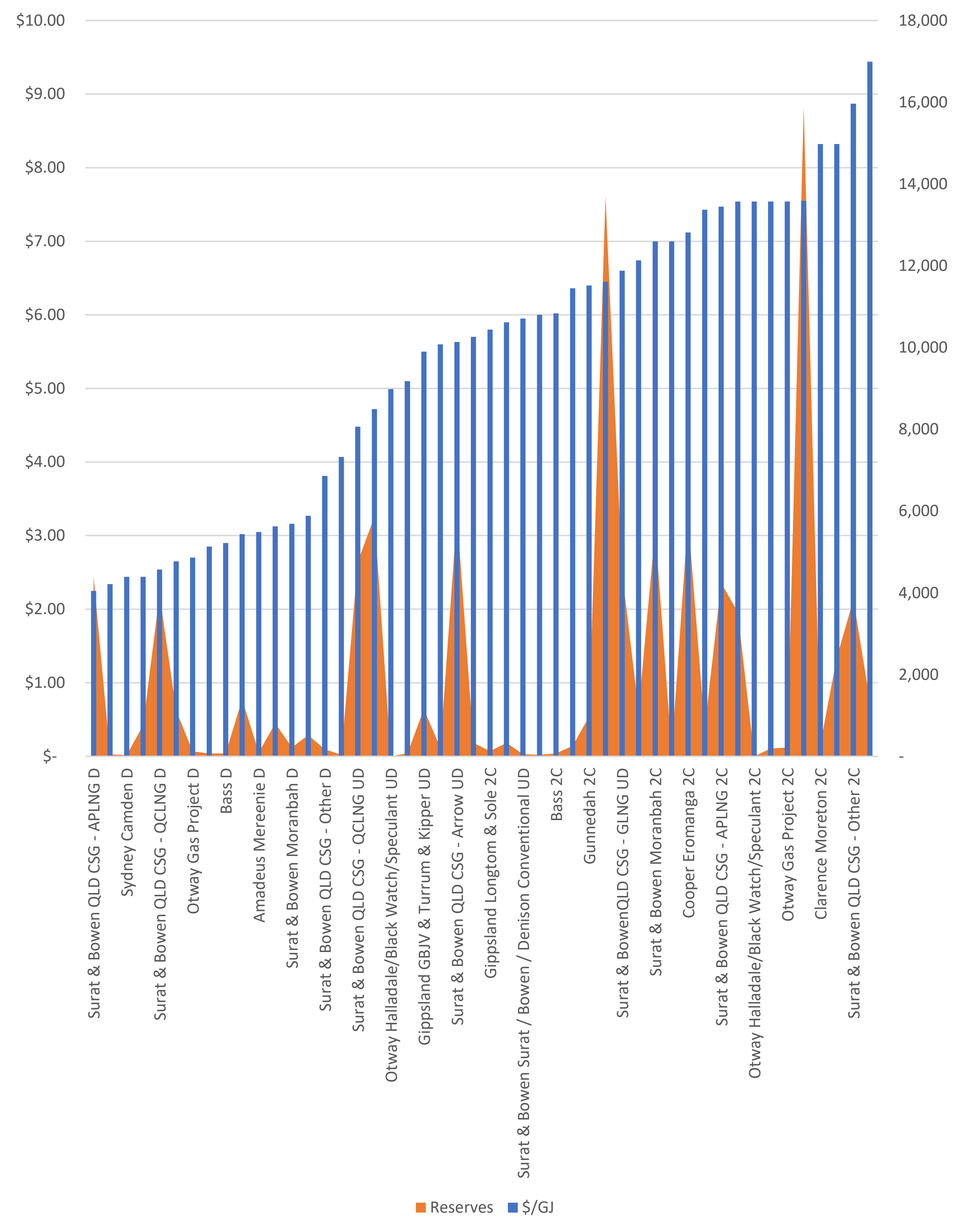
5. Economic Viability of the Narrabri Gas Project

5.1 Narrabri Gas Project Production Costs

As previously outlined above, in its 2020 Gas Statement of Opportunities report, the AEMO (2020) provided an updated estimate for production costs at the NGP of $6.40 per GJ. Based on this revised figure, the NGP is still a relatively high cost gas development project ranking 31 out of 48 actual and undeveloped gas projects in terms of production costs.

There are 15 developed and 15 undeveloped gas projects with lower estimated production costs than the NGP. The 15 undeveloped gas projects with lower production costs represent in excess of 19,000 PJ of 2P and 2C natural gas resources. The estimate of production costs and gas resources for both developed and undeveloped gas projects is provided in Figure 10 below, whereby the estimated production costs for each project provides an effective gas supply curve for the Eastern Gas Region.

*Figure 10: Estimated Supply Curve for Developed and Undeveloped Gas Project ($/GJ) and Estimated 2P and 2C Gas Resources for the Eastern Gas Region (PJ)**



Source: AEMO (2020).
* D – 2P developed gas project, UD – 2P undeveloped gas project, 2C – 2C undeveloped gas project.

There appear to be three main risks to the commercial viability of the NGP:

1. imported gas from Queensland currently contracted to LNG export markets redirected towards the domestic market
2. the development of an LNG import terminal
3. the discovery and development of lower cost gas resources in the Eastern Gas Region.

The first of these risks – arising from the redirection of imported gas to domestic markets – is discussed in sections 5.2 and 5.3 below. The second risk relating to import competition arising from the construction of an LNG import terminal is discussed in section 5.4. Both of these risks are critically related to international prices for LNG.

In relation to the third risk, it has been suggested that Victoria's onshore gas basins could in fact house Australia's second largest gas reserves (Gottliebsen, 2019). Although there is no evidence of gas resources present of this magnitude, the Geological Survey of Victoria (2020) has nonetheless suggested that there could be conventional gas resources of up to 830 PJ of potentially discoverable and extractable gas in the onshore Gippsland and Otway Basins, comparable with NGP's 2C gas resources of 970 PJ. However, even if such gas resources were present in Victoria's onshore basins, it would still take several years to properly assess and then extract if they proved to be commercially viable. On this basis, consideration of the discovery and development of lower cost gas resources will not be considered further.

5.2 Asian LNG Trading

LNG prices in Asia have traditionally been based on the price of Japanese Customs-Cleared Crude Oil price, more colloquially referred to as the Japan Crude Cocktail (JCC) price mechanism, a published index of the prices of crude oils imported into Japan (Rogers & Stern, 2014, p. 1).

The crude oil price linkage was introduced into Japanese LNG import contracts during the 1970s when crude oil was the main competing fuel to gas in electricity power generation (Rogers & Stern, 2014, p. 17). Oil-linked formula and long-term commitments have been key components of LNG supply contracts in Japan since around 1985 as large-scale financing associated with LNG liquefaction projects commanded commitments of nearly 20 years (Platts, 2016, pp. 6-7). Long-term contracts provided buyers with security of energy supply, while producers received certainty when making large scale, long-term investment decisions (Jacobs, 2011, p. 23). Long-term contracts are also a means of sharing commercial risks among parties: the buyer takes a volume risk by committing to a minimum off-take quantity (commonly known as a 'take-or-pay' clause), whereas the seller takes a price risk by ensuring the competitiveness of natural gas on the buyer's final market through a price indexation mechanism (International Energy Agency and the and Korea Energy Economics Institute, 2019, p. 63).

By the time that Japan was joined by other LNG importers in the Pacific Basin (South Korea in 1986 and Taiwan in 1990), the JCC price mechanism was already well established and LNG exporters were unwilling to countenance any other mechanism (Rogers & Stern, 2014, p. 18).

The price of LNG is generally given per million British thermal units (MMBtu), a thermal unit that measures the amount of energy required to heat one pound of water from 59°F to 60°F at a pressure of 14.696 psia (i.e. atmospheric pressure at sea level) (Collier, 2019). On average, one MMBtu of natural gas has approximately 17 per cent of the energy content of a barrel of oil. As a result, the price for one MMBtu of LNG in a crude oil-linked LNG pricing formula will be a similar percentage of the price of one barrel of oil using the relevant oil price index. This percentage is known as the price slope.

In generic terms, the formula linking the price of LNG to JCC can be approximated by the following equation:

$$Price_{LNG} = \alpha + \beta Price_{JCC} \qquad (1)$$

where $Price_{LNG}$ is the long-term delivered contract price of Asian LNG (measured in US$/MMBtu) and $Price_{JCC}$ is the JCC price of oil (measured in US$ per barrel), often measured as a lagged average of the Brent oil price (Cassidy & Kosev, 2015, p. 37). *β* is the price slope, which determines the sensitivity of LNG prices to changes in the oil price benchmark (factoring in the conversion between US$ per barrel and US$ per MMBtu), and α is a constant that reflects transportation costs. Most LNG long-term contracts in Japan are linked to trailing three-month average of JCC prices (Platts, 2016, p. 7).

The main focus in commercial negotiations utilising the JCC has been upon the determining the value of the slope (Rogers & Stern, 2014, p. 18). The Australian LNG pricing slope reportedly ranges between 12 and 15 per cent (Cassidy & Kosev, 2015, p. 37).

It has been common for long-term LNG supply contracts to have formulas that are non-linear, incorporating an 'S-curve' that moderates the impact of both high and low oil prices upon the LNG price (Jacobs, 2011, p. 24). S curves flatten the slope of the relationship between oil prices and gas prices at prices lower and higher than expected market conditions (Jensen, 2011, p. 17n). They thus tend to protect buyers when oil prices are high and sellers when prices are low.

Historically, the linkage between LNG and crude oil prices was in general accepted as a reasonable practice in Asia until around 2008 (Platts, 2016, p. 2). However, concerns began to emerge following crude oil price fluctuations (Productivity Commission, 2015, p. 49). There have been two recent episodes when long-term LNG contract prices indexed to the JCC and LNG spot prices have decoupled, prompting reconsideration of the use of the JCC as an appropriate benchmark upon which to base LNG prices.

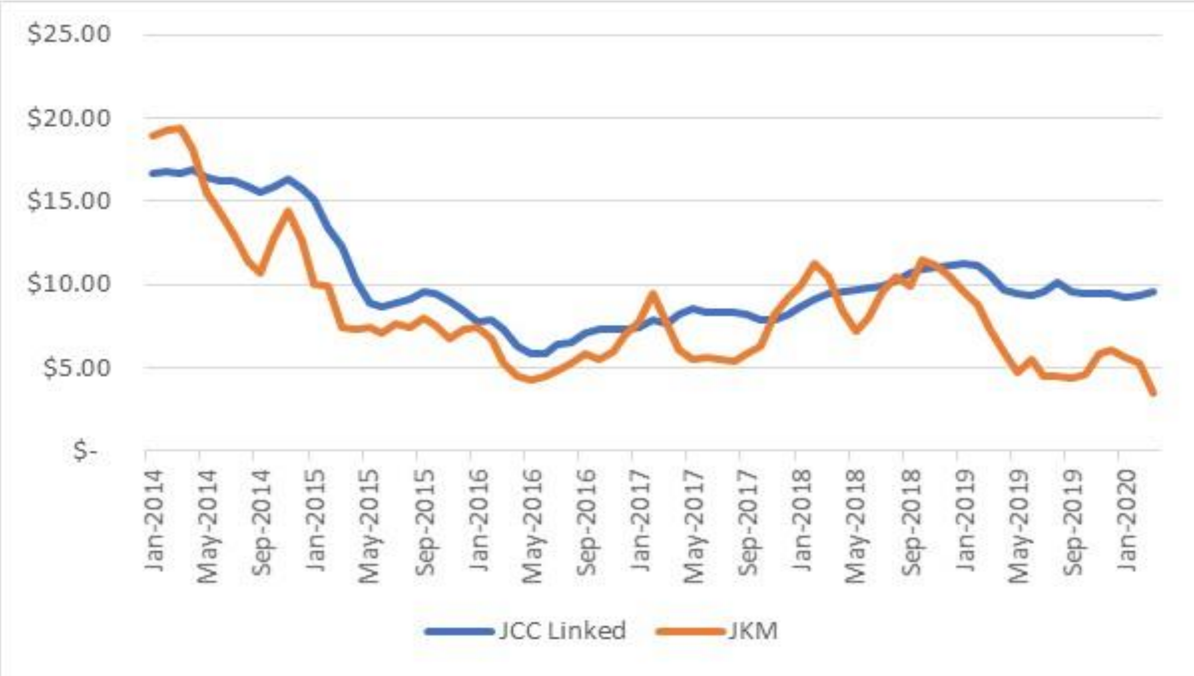
The most widely quoted measure of the prices of spot LNG trades in Asia is the Japan-Korea Marker (JKM) price published by Platts (Alim, Hartley, & Lan, 2015, p. 2). The JKM is Platts' price assessment for physical LNG spot cargoes delivered ex-ship into northeast Asia (Australian Competition and Consumer Commission, 2018, p. 10). These daily price assessments are published by Platts (to subscribers) in US$ per MMBtu on the basis of information obtained from market participants such as producers, consumers, traders, brokers, shippers and other active spot market participants. Information that is considered by Platts when making price assessments includes firm offers and bids, expressions of interest, confirmed trades, and third party reports of transactional activity. The JKM has been adopted as a price reference in contracts, both within Japan itself and more broadly in Asia as well as in the global context (Mexico, Brazil, India, etc) (Platts, 2016, p. 3).

In the middle of 2014 Asian LNG spot prices began declining well below oil linked prices as LNG demand weakened but then oil prices also fell sharply, with prices recoupling (Fulwood, 2019, p. 3). Average spot prices in 2016 and 2017 were around US$1 less than average contract prices, while in 2018 they were around the same average level.

Another bout of decoupling that is still underway commenced in early 2019 when spot prices began to fall sharply, from over US$10 in January to less than US$5 by May (Fulwood, 2019, p. 3). At the time, oil prices were above $70 per barrel, leading to Japan contract prices above US$10.

Comparison of the JKM with the JCC linked LNG price is provided in Figure 11 below.

Figure 11: Japan-Korea Marker (JKM) and JCC LNG Prices – January 2014 to March 2020 (US$ per MMBtu)



Source: Platts LNG Daily.

It has been observed that customers tend to demand change in the formation of prices when the current situation creates a significant disadvantage for them (The Oxford Institute for Energy Studies, 2020, p. 4). This occurred in Europe when spot and contract prices diverged and customers began to demand an end to oil-linked pricing, prompting new European Union rules on market liberalisation. The trend away from oil-linked pricing in Asia has been much more gradual. However, there are signs of a customer response to the significant divergence between spot and contract prices that opened up during 2019. The instance of arbitration cases on long-term contracts has started to increase, albeit from a low base, and rumblings of discontent from those tied into higher-priced oil linked contracts has grown.

5.2.1 US Shale Gas Revolution and the Increasing LNG Spot Trading in Asia

A number of developments have destabilised traditional LNG pricing arrangements in Asian markets.

The expansion of US shale gas production arising from technological advances in combining horizontal drilling and fracking has generated growth in production that has been expanding much faster than US domestic consumption, and created opportunities for US producers to export natural gas to the Asia Pacific region where gas prices have been traditionally significantly higher than elsewhere in the world (Ripple, 2016, p. 23).

The increase in LNG prices in the Asia-Pacific market following the Fukushima nuclear power plant accident in Japan was also an important driver for LNG exports from the US (Foss & Gülen, 2016, p. 33). The 2011 Fukushima nuclear power plant accident disabled the Japanese nuclear power generation fleet, which led to a sudden surge in Japanese and Chinese gas demand (Kim, 2018, p. 129).

One characteristic of the U.S. market structure that facilitated a relatively rapid move into export markets was the existence of several LNG regasification terminals along the US Gulf and East Coasts. Some of these facilities date back to the 1970s, but they contained a significant share of the capital requirements for an LNG export operation. They were already connected to the pipeline grid, they had dock facilities built to handle LNG tankers, and they had LNG storage facilities. While not insignificant, this meant that to enter the natural gas export trade these facilities needed to only construct liquefaction trains. This meant that relative to other projects around the world, the US projects (at least the earliest ones proposed) had a significant capital expenditure advantage over virtually all greenfield projects and even some brownfield projects. Even so, the newly emerging opportunities also generated a rush of new applications to construct natural gas liquefaction facilities where none had previously existed (Ripple, 2016, p. 23). The first US exports of LNG occurred in February 2016 (Ministry of Economy, Trade and Industry, Government of Japan, 2016, p. 2).

The underlying pricing reference point for US gas is a pipeline interconnection hub at Henry, Louisiana (known as Henry Hub) (Jensen, 2011, p. 14). US LNG contracts offer an alternative to oil-linked pricing (Department of Industry, Innovation and Science, 2018, p. 43). Prices are indexed to the Henry Hub pricing point, plus shipping and liquefaction tolling fees. While pricing arrangements vary across US LNG contracts, the rule of thumb is that the cost of US LNG can be broken into four components: the Henry Hub gas price, a 15 per cent surcharge on the Henry Hub price to cover the cost of liquefaction and pipeline costs from Henry Hub to liquefaction plants, a fixed capacity charge (also known as a 'tolling fee') that covers the capital costs of the liquefaction plant, and transport costs from the US to Asia (Department of Industry, Innovation and Science, 2018, p. 102).

In late 2014 Nhu Che and Tom Kompas (2014, p. 10) from the Australian National University predicted in relation to forthcoming LNG imports to Asia from the US that:

> *Given the disparity of LNG prices and rapid development of shale gas, North America will be an important LNG supplier, making the potential integration of Henry Hub pricing into the Asia-Pacific region likely. Henry Hub prices are attractive to LNG importers in Asia-Pacific region, given they are historically less volatile at lower and more stable levels. The risk of linking to high oil prices, which are uncertain by geopolitical, economic and accident events, is also eliminated.*

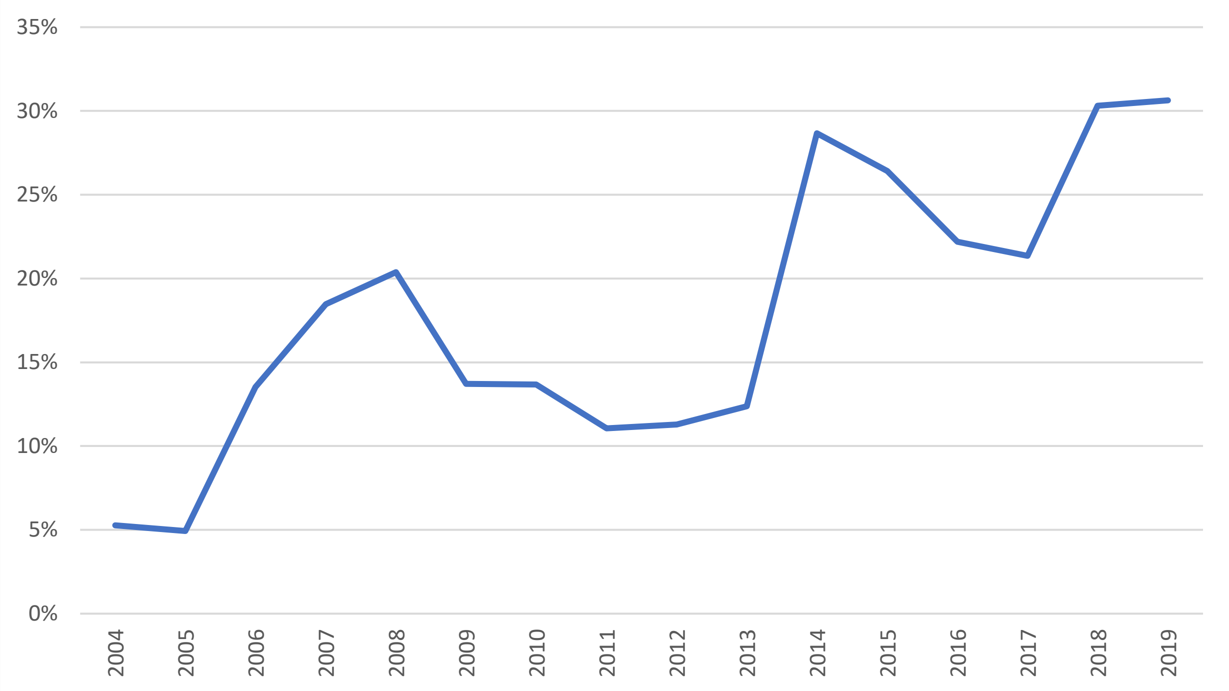
Dr Jeff Brown, President of global energy consulting firm Facts Global Energy (FGE), commented back in 2015 that he expected long-term LNG contract renegotiation pressures to grow in light of surging supplies out of Australia and the United States, with Asian spot prices likely to track well below term contract prices for several years (Evans, 2015). In this regard, the Japanese Government (Ministry of Economy, Trade and Industry, Government of Japan, 2016, p. 7) has been seeking to overhaul long-term LNG contractual arrangement that index LNG prices to crude oil prices to better reflect demand and supply market conditions and has declared the linking the pricing of LNG to crude oil prices as no longer necessarily justifiable. According to the Japanese Government (Ministry of Economy, Trade and Industry, Government of Japan, 2016, p. 8):

> *The establishment of price indices which accurately reflect the supply and demand of LNG itself will not only facilitate spot trading but also contribute to stabilizing import prices through immediately helping to diversify price formulae, which used to be mainly linked to crude oil prices.*

Trade on a spot basis and under short-term contracts (of less than four years) has increased from just under 14 per cent of all Asian LNG imports in 2009 to almost 31 per cent in 2019.[15] This is outlined in Figure 12 below.

[15] See International Group of Liquified Natural Gas Importers (2010; 2020).

Figure 12: Spot and Short-term Contracts as a Percentage of Total Asian LNG Imports – 2004 to 2019



Source: International Group of Liquefied Natural Gas Importers (2020).

5.2.3 East Coast LNG Export Arrangements with Asia

The three Queensland LNG export projects are understood to be underwritten by long-term contracts of 20 years or more that commenced once each train became commercial, with LNG prices linked to crude oil prices coupled with take-or-pay provisions. According to Origin Energy (2018, p. 36):

> *The vast majority of APLNG gas reserves are sold under 20 year take or pay contracts to major Asian counterparties on an oil-linked basis …*

Take-or-pay provisions allow the buyer to unilaterally decide to take less than the contracted volume in return for compensating the seller for the supply that was not taken (Hartley, 2014, p. 7).

The LNG prices linked to crude oil prices are based on the JCC, as Origin Energy (2019, p. 186) has stated in relation to the APLNG:

> *APLNG's long term LNG sales contracts are priced based on the JCC index.*

Similarly, Santos (2020a, p. 3) refers to the linkage of LNG sales by GLNG to a lagged JCC price in its quarterly production updates.

It is understood that the Queensland LNG export projects have contracted at price slopes in the range 0.12 to 0.155 (Lewis Grey Advisory, 2017, p. 20). In the calculation of its LNG price from Gladstone, Argus Media (2020) uses a price slope of 14.85 per cent.

It has been estimated that long-term contracts account for around 76 per cent of the total production capacity of the Queensland LNG export projects on a long term basis (McKinsey & Company, 2017, p. 11). In both the 2017-18 and 2018-19 financial years, long-term contract sales accounted for in excess of 90 per cent of LNG sales from APLNG (Origin Energy Ltd, 2019, p. 40). Over and above the long-term contracted supplies, additional quantities of gas can be sold on various spot LNG markets (Grafton, Shi, & Cronshaw, 2018, p. 45) or gas can be sold back into the Eastern Gas Region. According to Origin Energy (2018, p. 27):

Gas volumes produced by APLNG in excess of the contracted volumes are sold to the domestic gas market and the spot LNG market.

In the 2017-18 financial year, spot sales of LNG accounted for almost 9 per cent of LNG production of APLNG, falling to less than 4 per cent in the 2018-19 financial year (Origin Energy Ltd, 2019, p. 40), reflecting a dramatic fall in LNG spot prices in Asia.

Origin Energy (2014) has previously stated that APLNG had a breakeven point at average oil prices of around US$40-45 per barrel. Similarly, Santos (2015c) has said that the GLNG train 1 has a breakeven point of US$40 per barrel. More recently, Origin Energy (2020, p. 51) has estimated the breakeven point for APLNG at an average oil price of around US$29-32 per barrel.

As outlined in Table 6 below, most of the long-term contracts for the Queensland LNG export projects are under the most flexible free-on-board (FOB) agreements. FOB contracts shift the risk of transportation from the producer to the purchaser, who is responsible for transportation and associated costs (Cassidy & Kosev, 2015, p. 37n). On this basis, the constant in the pricing formula to allow for the cost of transportation has been set at zero in FOB agreements (Lewis Grey Advisory, 2017, p. 20). This contrasts with the other main form of sales agreement, where the purchase price includes costs, insurance and freight (Cassidy & Kosev, 2015, p. 37n). This typically makes the seller responsible for transportation and is referred to as 'delivered ex-ship'.

Table 6: Contractual Arrangements for Queensland LNG Export Projects

Project Name	Contract Buyer	Acquisition (MTPA)	Duration	Delivery Format
QCLNG Train 1	CNOOC	3.6	2015 to 2035	Delivered Ex-Ship
QCLNG Train 2	Tokyo Gas	1.2	2015 to 2035	FOB
QCLNG Train 1 and Train 2	Shell	3.8	2014 to 2034	FOB
GLNG Train 1	PETRONAS	1.8	2015 to 2035	FOB
GLNG Train 1	KOGAS	1.7	2015 to 2015	FOB
GLNG Train 2	PETRONAS	1.7	2016 to 2036	FOB
GLNG Train 2	KOGAS	1.8	2016 to 2036	FOB
APLNG Train 1 and Train 2	Sinopec	7.6	2016 to 2036	FOB
APLNG Train 2	Kansai Electric	1	2016 to 2035	FOB

Sources: International Group of Liquified Natural Gas Importers (2020), International Gas Union (2019) and Santos (2010).

Long-term contract price arrangements can often be subject to periodic renegotiation (e.g. every three to five years) (Cassidy & Kosev, 2015, p. 37). Renegotiations may occur due to bilateral agreement or can be triggered contractually by large oil price movements. In this regard, Origin (2019, p. 16) commented last year:

As is typical in long-term LNG contracts, APLNG's LNG contracts contain periodic price reviews every 5–7 years. The first opportunity for such a price review will arise under APLNG's LNG contract with Sinopec within the next 18 months and requires the parties to use reasonable endeavours to agree on any changes required to achieve the objective of in-market pricing. In the absence of agreement, neither party is permitted to request this first price review to be

> *determined by an expert. Subsequent price reviews can be referred to expert determination in the absence of agreement between the parties.*

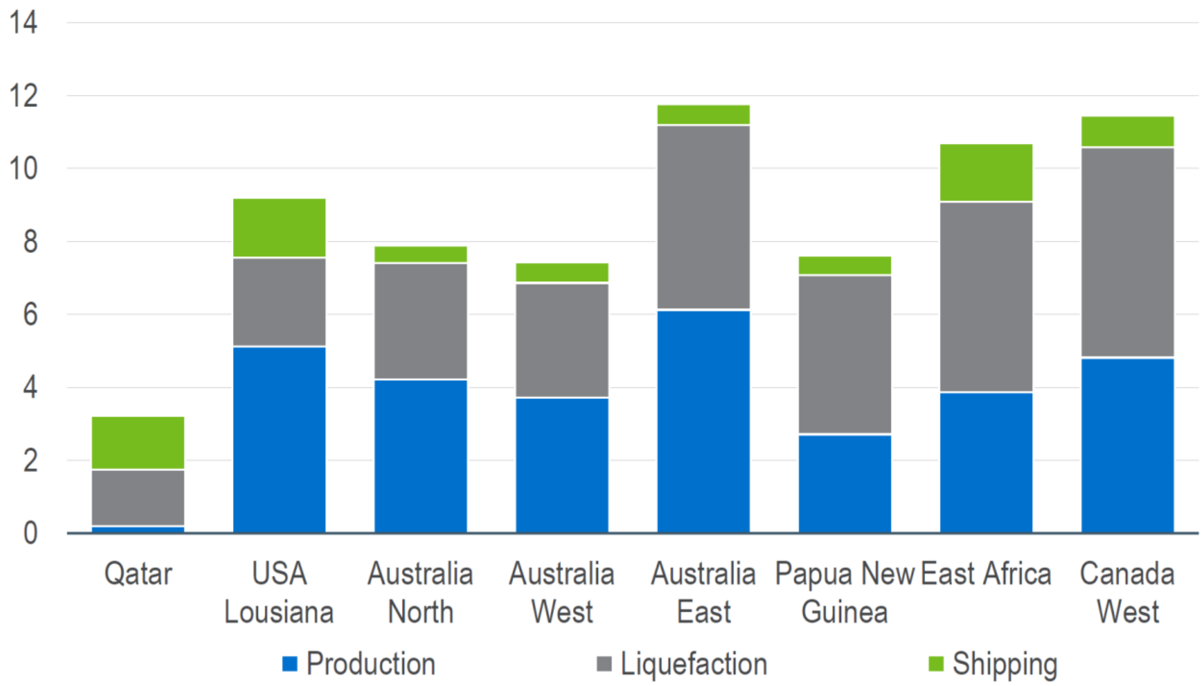
LNG buyers also have some flexibility on long-term oil-linked contracts, allowing them to increase/decrease long-term contract purchases depending on the relative attractiveness of the LNG spot market (Department of Industry, Innovation and Science, 2018, p. 104).

5.3 Incentives Facing LNG Suppliers and their Asian Customers

Recent developments in Asian LNG markets create some risks for the commercial viability of the NGP.

Bruce Robertson (2017, p. 4) from the Institute for Energy Economics and Financial Analysis has observed that in all resource markets, highest-cost producers have to curtail production first, and that the three Queensland LNG export projects "sit at the very apex of the global cost curve, so these plants will feel the pressure to shut in capacity most acutely." Similarly, Platts Commodity News (S&P Global Platts, 2020) has observed the three Queensland LNG export projects "are on the higher end of the cost spectrum" in terms of both gas and liquefaction costs. This is borne out in Figure 13 below by Dr Nelly Mikhaielv (2016, p. 12) from energy consultants Nextant.

Figure 13: Cost Components from Various Supply Sources to Japan ('delivered ex-ship') for Calendar Year 2024 (US$ per MMBtu)



Source: Mikhaielv (2016, p. 12).

The gas feedstock used by the Queensland LNG export projects is arguably the most expensive in the world because it is primarily based on CSG where production requires the additional expense of drilling new wells each year as compared to conventional gas resources. Maintaining CSG production requires higher operating cost and ongoing capital expenditure to support a continuous program of drilling and new infrastructure development (Australian Competition and Consumer Commission, 2016, p. 62). According to Dr Graeme Bethune and Rick Wilkinson (2019, p. 521) of energy advisory firm EnergyQuest in relation to gas production from Queensland CSG:

> *Just to maintain CSG production at current levels requires the drilling of 1000 to 1400 wells per year. With the associated infrastructure, this is an ongoing investment in the order of $2 to 3 billion per year. At least one-third of the CSG to*

LNG capital is yet to be spent. This is unlike any of the other LNG projects in Australia, where the drilling of production wells is usually completed for the commissioning of the project.

LNG from CSG is also less robust than conventional LNG train plant economics, as it has no by-product revenue stream from natural gas liquids (Ferrier Hodgson, 2017, p. 13).

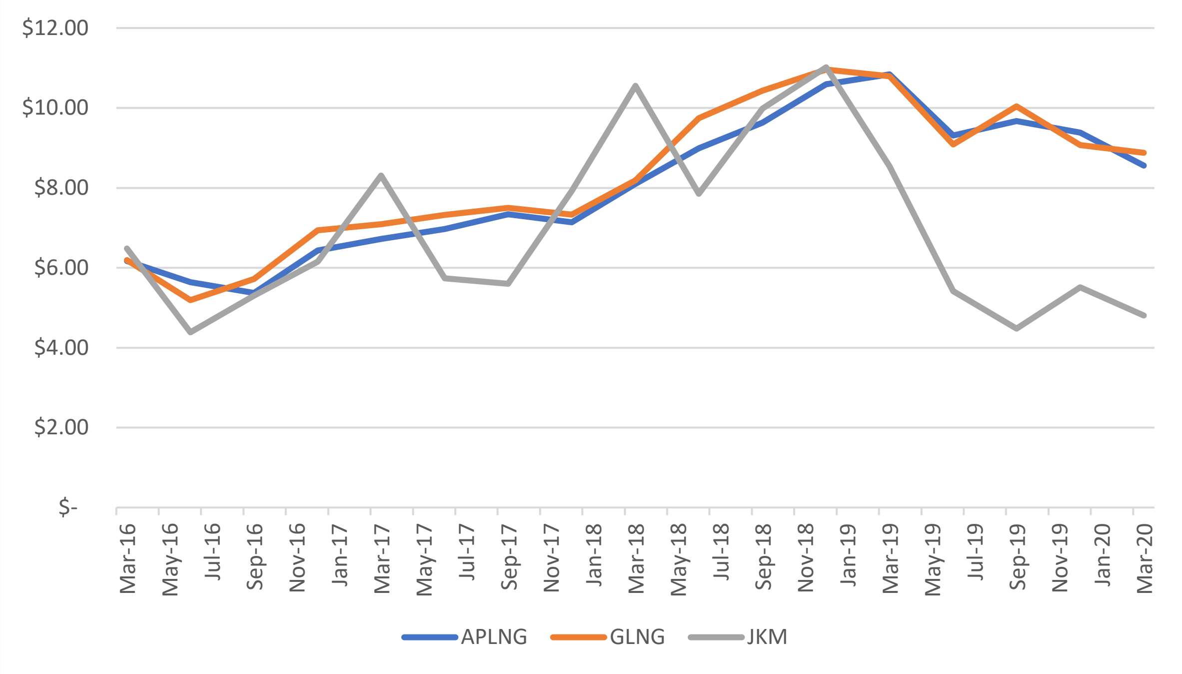
The Queensland LNG export projects have long-term supply contracts with LNG prices linked to crude oil prices based on the JCC. As a consequence, any drop in the price of oil tends to affect LNG prices between three and six months later (Crossley, 2018, p. 146).

When the contracts for the Queensland LNG export projects were negotiated the oil price was over US$100/barrel, hence implying a contract price in excess US$14 per MMbtu, well in excess of the long run marginal cost and generating returns above the cost of capital for the sellers (Lewis Grey Advisory, 2017, p. 20). By late April 2020 the oil price had fallen to below US$20 per barrel, implying LNG contract prices of less than US$3 per MMbtu in forthcoming months, in turn suggesting potential losses on the horizon for the Queensland LNG export projects based on a breakeven point for APLNG at an average oil price of around US$29-32 per barrel.

While ongoing low crude oil prices provide an incentive for the Queensland LNG export projects to cut back on their LNG export sales due to the prospect of incurring losses, crude oil prices below US$30 per barrel are unlikely to persist. By late May 2020, crude oil prices had recovered from recent lows of less than US$20 per barrel and were above US$30 per barrel. The World Bank (2020) is forecasting crude oil prices to gradually recover from recent lows and average US$35 per barrel over this year before rising to US$42 per barrel in 2021. Over the long term, the World Bank is expecting crude oil prices to continue to rise over the years ahead, reaching US$70 per barrel by 2030. Crude oil prices are likely to gradually recover and remain above the breakeven point for the Queensland LNG export projects, thus ensuring the Queensland LNG export projects will likely remain viable provided their long-term supply contracts remain in force. On this basis, low crude oil prices do not pose an immediate threat to the commercial viability of the NGP as they are unlikely to result in the redirection of Queensland CSG back into the domestic market.

However, there is a risk to the commercial viability of the NGP presented by the significant gap that has opened up between long-term LNG contract prices based on the JCC and LNG spot prices in Asia as outlined in Figure 11 above. A price gap is also apparent when comparing the average LNG prices received by two of the three Queensland LNG export projects and average spot LNG prices on a quarterly basis as outlined in Figure 14 below.

Figure 14: Quarterly Average LNG Prices for APLNG, GLNG and the JKM: March Quarter 2016 to March Quarter 2020 (US$ per MMbtu)



Sources: Origin Energy (2020a), Santos (2020a) and Platts LNG Daily.

When LNG spot prices in Asia are high, this creates incentives for the Queensland LNG export projects to ramp up production to their full capacity (Lewis Grey Advisory, 2017, p. 60). This would occur regardless of whether buyers under long-term contract took their full contract entitlements. However, the converse of this is that low LNG spot prices in Asia provides opportunities and incentives for LNG buyers with long-term contracts to cut back contracted supply to their take-or-pay levels. In this regard, Peter Downey, Jon Thomas and Mark Stone (Downey, Thomas, & Stone, 2019, p. 68) from the Queensland Department of Natural Resources, Mines and Energy have warned:

> *The expansion of the LNG spot market has implications for pricing that pose a major challenge to Queensland's CSG-LNG projects. In addition to these projects being underwritten by long-term sales contracts, these contracts include the traditional pricing mechanism in which the prices are linked to that of oil. The expansion of the spot market as well as a divergence between oil and gas price over the period 2008–14 … is leading to a move away from oil-linked pricing towards prices based on significant gas trading hubs, such as the Henry Hub in the USA.*
>
> *The implications of a shift away from long-term oil-linked pricing towards more short-term and flexible gas-hub pricing may influence both the existing three projects and any expansion of the Queensland LNG industry.*

According to the AEMO (2020a, p. 26), in the short term lower international LNG prices arising from lower LNG spot prices as well as oil-linked JCC long-term contracts will likely increase the supply of gas from Queensland into the domestic market. However, in the longer term, AEMO suggests that lower international LNG prices may suppress exploration and development expenditure, reducing the longer term supply outlook.

The opening of a gap between long-term LNG contract prices based on the JCC and LNG spot prices creates incentives for buyers to take the minimum possible volumes allowed for under long-term

LNG supply contracts, renegotiate and/or even renege on contractual terms. According to the Commonwealth Department of Industry, Science, Energy and Resources (2020, p. 62):

> *If the large differential between spot and long-term contract prices persists, contract prices may come under downward pressure. Buyers are reportedly pushing to have contract prices lowered during the periodic price reviews that are built into long-term supply agreements, reducing purchases on long-term contracts and increasing spot cargo purchases where their contract permits. In the longer term as contracts expire, low spot prices relative to oil-linked prices may encourage buyers to push for shorter, more flexible, or more favourably-priced contracts.*

In 2015 it was reported that Chinese national oil companies (NOCs) were desperately trying to renegotiate term LNG import deals as they faced weaker gas demand and oversupply at home, including Sinopec in relation to its contract with APLNG (Evans, 2015). Aside from Chinese NOCs, Damon Evans (2015) writing in Petroleum Economist even suggested:

> *In future, legacy buyers, such as Japan, South Korea and Taiwan, might more openly pursue a strategy of buying low-priced cargoes, while backing out of long-term contracted volumes.*

As the gap between long-term contract prices and spot prices opened up last year, Origin Energy (2019, p. 38) reported in relation to APLNG that:

> *An LNG customer has elected to defer delivery of 30 cargoes over six years (2019–2024). The customer will pay for the deferred cargoes and APLNG expects to re-sell the gas during the period 2019–2024, and then deliver the deferred cargoes during the period from 2025 to the end of the LNG sale and purchase agreement.*

More recently there have been press reports that CNOOC issued *force majeure* notices covering its LNG purchases for February and March 2020 with at least three suppliers, including Shell (Jaganathan & Aizhu, 2020).[16] Shell is CNOOC's largest Australian supplier of LNG through the QGLNG project (Macdonald-Smith, 2020). Press reports further suggest the three suppliers rejected the *force majeure* notices they received from CNOOC on the grounds that high storage levels and slack demand were not *force majeure* events (LNG World News, 2020).

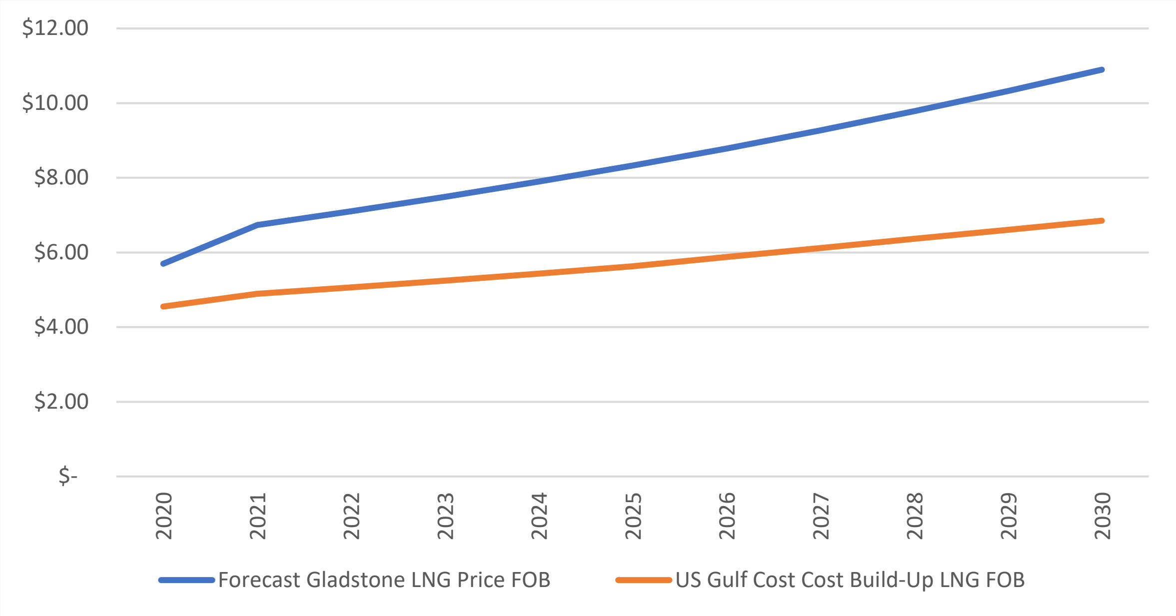
According to Ira Joseph (2020) from S&P Global Platts Analytics:

> *As we speak, force majeure clauses are being invoked throughout the entire LNG value chain. Buyers are postponing or cancelling contracts, and producers are doing the same with the building of new liquefaction capacity. Whether or not these invocations are legally valid is not the issue. What matters is that the dispute can be used as leverage for how gas will be priced in the future.*
>
> *One thing the coronavirus has revealed is that using oil indexation for gas pricing is just as dysfunctional on the way down as it is on the way up. Movements in oil markets do not reflect global gas balances in any way.*

[16] Force majeure, broadly speaking, refers to unexpected external circumstances that impede performance under a contract (Ason & Meidan, 2020, p. 2). Typically, force majeure clauses list examples of events that can be considered as force majeure including Acts of God (such as an earthquake, hurricane, or epidemic), acts of war, and acts of government.

Forecasts by the World Bank provide an opportunity to compare likely future long-term supply contract prices for the Queensland LNG export projects (FOB) as compared to an expected cost build-up of US LNG exports from the US Gulf Coast. This is outlined in Figure 15 below.

Figure 15: Forecasts for Queensland LNG Export Project Prices Versus a Cost Build-Up of US LNG Exports from the US Gulf Coast (FOB) (US$ per MMbtu)



Sources: World Bank (2020) forecasts for crude oil and Henry Hub gas prices.
Note: Cost build-up of US LNG exports from the US Gulf Coast based on three of the four components for standard US LNG supply contracts – the Henry Hub gas price, a 15 per cent surcharge on the Henry Hub price to cover the cost of liquefaction and pipeline costs from Henry Hub to liquefaction plants, a fixed capacity charge (also known as a 'tolling fee') that covers the capital costs of the liquefaction plant.[17] The cost of shipping freight to Asia has been excluded. The tolling fee has been set at US$2.25 per MMbtu.[18] Queensland LNG export prices based on a price slope of 14.85 per cent for crude oil prices plus US$0.50 per MMbtu.[19]

Figure 15 shows a growing gap between likely long-term supply contract prices for the Queensland LNG export projects and the cost of procuring LNG from the US Gulf Coast is likely to persist. While freight costs to Asia have not been included in the analysis above, the differential in freight costs from Gladstone to Asia as compared to the US Gulf Coast to Asia have been far less than US$1 per MMbtu for the past 12 months, while the gap in Figure 15 increases from US$1.15 in 2020 to just over US$4 by 2030.

This analysis suggests the long-term supply contracts of the Queensland LNG export projects will come under increasing pressure for renegotiation in terms of both prices and quantities from Asian spot LNG prices. As high cost suppliers of LNG, the Queensland LNG export projects are not price competitive with other international suppliers, suggesting that increasing quantities of Queensland CSG gas production could eventually be redirected back into the domestic market. In turn this provides a serious threat to the commercial viability of the NGP that has much higher expected production costs than existing Queensland CSG projects.

While the pipeline network to transport gas from Queensland to southern Australia is currently capacity constrained, the renegotiation of the Queensland LNG export projects' long-term supply contracts could provide an impetus for the development of the proposed Hunter Gas Pipeline (HGP). The HGP was originally given development approval back in February 2009, but is yet to begin

[17] See Department of Industry, Innovation and Science (2018, p. 102).
[18] See Ledesma and Fulwood (2019, p. 26).
[19] See Argus Media (2020, p. 6).

construction, and recently requested a lapse date extension of five years that was approved by the NSW Government (Tsaousis, 2020). The proposed 820-kilometre pipeline would run from Queensland's gas hub at Wallumbilla, near Roma, to Newcastle, via Moree and the Hunter Valley and cost an estimated $1.2 billion to construct, and it has been suggested that it could cut the cost of transporting gas from Queensland to NSW by 40 per cent (Macdonald-Smith, 2019).

5.4 Competitiveness of LNG Imports

In January this year, Santos Chief Executive Kevin Gallagher declared:

> *If we can develop Narrabri gas, it will be the most competitively-priced gas for NSW customers, and it will always be cheaper than LNG imports, especially when gas prices are high in Asia. (Macdonald-Smith, 2020a)*

Similarly, in its submission to the NSW Legislative Council inquiry into the implementation of the recommendations contained in the NSW Chief Scientist's Independent Review of Coal Seam Gas Activities in NSW, Santos (2019, p. 5) contended that:

> *While import terminals may add supply to the market, imported gas will not be cheaper than gas developed within NSW.*

Echoing the same sentiment, in its 2019 Gas Statement of Opportunities report, the AEMO (2019, p. 3) asserted:

> *Continued interest in LNG import terminals, particularly in Victoria, New South Wales, and South Australia, would be expected to help relieve pressure on meeting southern gas demand during peak periods and assist in reducing pipeline constraints, but may do little to ease gas pricing pressures.*

However, rather tellingly, the AEMO chose not to repeat the same reflection on the price competitiveness of LNG imports in its 2020 Gas Statement of Opportunities report.

In August 2017 AGL (2017) announced Crib Point on Western Port Bay near Hastings in Victoria as the preferred site for its FRSU and pipeline to supply customers in south eastern Australia. AGL (2019a) expects the first gas to be delivered from the proposed terminal in the first half of 2023 and the Victorian Government is currently undertaking an Environment Effects Statement (EES) process to assess the project. In June 2019, AGL selected Höegh Esperanza as the FSRU for the project (International Group of Liquefied Natural Gas Importers, 2020, p. 44).

In December 2018 the South Korea-based Energy Projects and Infrastructure Korea or EPIK Co. Ltd. (EPIK) (2018), an LNG FSRU project development company, announced that it has entered into a Project Development Option Agreement with the Port of Newcastle to commence preliminary works on a proposed LNG FSRU import terminal. In August 2019, the project was declared Critical State Significant Infrastructure by the NSW Government (Barilaro & Stokes, 2019).

In April 2019, Australian Industrial Energy (AIE) (2019), a joint venture between Andrew Forrest’s Squadron Energy; global energy infrastructure investor Marubeni Corporation (Marubeni) and the world's largest buyer of LNG, JERA Co. Inc. (JERA), received planning approval from the NSW Government for an LNG import terminal at Port Kembla known as the Port Kembla Gas Terminal (PKGT). In April 2020, AIE (2020) received approval from the NSW Government to modify its existing planning approval for the PKGT enabling it to import more LNG during the high demand winter months. The $250 million project will involve minimal infrastructure, consisting of four key components:

- LNG tankers
- The Höegh Galleon, a FSRU which will remain moored at Berth 101 in Port Kembla’s Inner Harbour

- Wharf facilities – the existing berth will be modified and upgraded to include offloading arms to transfer gas from the FSRU to the wharf
- A standard high-pressure pipeline connection from the wharf to the Eastern Gas Pipeline.

AIE has signed a 10 year charter deal with Höegh LNG to secure its FRSU (Macdonald-Smith, 2018).

The revised planning approval enables AIE to import up to 115 PJ of LNG per annum (GHD, 2019, p. 15). Santos' partner in the NGP EnergyAustralia has signed a preliminary agreement for a five-year gas supply contract to take 15 PJ per annum for its residential and industrial customers as well as for electricity generation (Australian Industrial Energy and EnergyAustralia, 2019). Peter Mitchley, the head of the AIE venture, said a final investment decision could be taken in the September quarter 2020, depending on agreements with customers that would use gas from the terminal (Macdonald-Smith, 2020b).

Energy Consultant Nicholas Mumford (2019, p. 666) has contended that the clear commercial reality of gas supply sourced from an LNG import terminal is that it can only be supported by high gas prices. The reality, based on the available evidence, is that high gas prices appear to have been locked in across the Eastern Gas Region in any event.

The Productivity Commission (2015, p. 6) has previously reflected that a common understanding is that prices in the Eastern Australian gas market will eventually converge to an LNG netback price — the export price of LNG less the costs of transport and liquefaction. According to the Productivity Commission (2015, p. 6).

> *This is a good rule of thumb because prices for LNG exports represent the opportunity cost of supplying gas to the eastern market.*

In February this year the ACCC (2020, p. 1) raised concerns that gas prices in the Eastern Gas Region had not fallen in line with falls in the netback price:

> *Prices offered in the East Coast Gas Market have remained relatively steady, mostly within a range of around $9–12/GJ. However, domestic price offers have not fallen in line with the decline in LNG netback (export parity) price expectations for 2020.*

According to the ACCC (2020, p. 57), this disparity can be observed in the prices offered by all suppliers in Queensland, including LNG producers. The ACCC (2020, p. 6) also raised a further concern regarding the inclusion of a fixed price component for which there appeared to be no apparent justification for:

> *Of particular concern is the inclusion of a fixed price component, above a JKM-linked component that is equivalent or close to LNG netback prices, observed in some offers by LNG producers.*

The ACCC (2020, p. 57) also went on to highlight the fact that one of the Queensland LNG projects was intending to sell a number of spot LNG cargoes in late 2019 during 2020 for prices presumably lower than they could have received in the domestic market:

> *Understanding this price differential is particularly important in light of recent reports that APLNG is offering to sell an additional six to 12 LNG cargoes in 2020 through a short-term LNG strip contract. These cargoes would likely be sold at prices reflective of current market expectations for LNG spot prices over 2020, which as noted above, are below domestic price offers in Queensland.*

This is not rational behaviour by suppliers in competitive markets.

While both the Productivity Commission (2015, p. 6) and ACCC (2020, pp. 57-58) have recognised that there are legitimate circumstances under which prices in the Eastern Gas Region could diverge from netback prices for a period, none of those conditions appear to be prevalent at the moment. This has prompted the ACCC (2020, p. 58) conclude in relation to the matter that:

> *… it is surprising that Queensland price offers did not continue to fall over the period between May and August 2019. It is our expectation that LNG producers would have sought to take advantage of the difference in domestic and expected LNG netback prices by increasing their sales of gas to the domestic market (which, all other things equal, would be expected to put downward pressure on prices).*

The ACCC appears to be implying that Queensland gas producers may be exercising market power to maintain higher gas prices in the Eastern Gas Region.

5.4.1 Do Gas Producers Exercise Market Power?

Concerns regarding the exercise of market power by gas producers in the Eastern Gas Region are not new. As the Productivity Commission (2015, p. 23) has previously observed:

> *Some gas market stakeholders have argued that gas producers in the eastern Australian gas market have market power, and that the exercise of this power is affecting market outcomes, including the ability to secure a contract on competitive terms for gas purchases. A number of large industrial gas users have indicated that they are unable to secure contracts at any price (or that there is a risk of this happening). Some users have suggested that this too is a manifestation of the exercise of market power.*

The economic and legal literature has provided several different definitions of market power. One commonly used definition in economics is that provided by US economist Abe Lerner which is the ability of a firm to push its price above marginal cost (Lerner, 1934). However, the problem with the Lerner definition of market power is that it is often difficult to measure marginal cost in the real world.

Another definition of market power comes from prominent US competition law scholars Carl Kaysen and Donald Turner (1959, p. 75):

> *A firm possesses market power when it can behave persistently in a manner different from the behaviour that a competitive market would enforce on a firm facing otherwise similar cost and demand conditions.*

This definition has been used by the ACCC (2002, p. 64) and in a prominent Australian legal judgement.[20]

Identifying firms that have substantial market power enables one to distinguish between conduct that might harm consumers and conduct that cannot (Bork & Sidak, 2013, p. 511). Unfortunately, there is no definitive test for the exercise of market power. Instead, one must rely on a series of partial indicators in order to determine whether firms participating in a market are exercising market power. According to US competition law scholar Judge Robert Bork and Professor Gregory Sidak of Tilburg University (2013, p. 512):

> *Courts and competition authorities around the globe typically rely on indirect evidence of market power, such as market share and barriers to entry.*

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[20] Cited with approval by Dawson J in *Queensland Wire Industries Proprietary Limited v The Broken Hill Proprietary Company Ltd and Anor* (1989) 167 CLR 177 at 200.

Information on market share can be a useful first step in competition analysis and can provide guidance as to whether a given case is more likely to raise oligopoly issues or single firm conduct issues (Organisation for Economic Co-operation and Development, 2006, p. 8). An oligopoly is a market structure characterised by a few participants. It may include a “competitive fringe” of numerous smaller sellers who behave competitively because each is too small individually to affect prices or output (Areeda, Solow, & Hovenkamp, 2002, p. 9).

There is no single determinate solution to the problem of oligopoly with many possible outcomes being postulated. The range of solutions runs the full gamut of possible outcomes from that reminiscent of perfect competition to that of a monopoly (Areeda, Solow, & Hovenkamp, 2002, p. 10). The reason that there is no single unique solution to the problem posed by oligopoly is because of the interdependency of market participants. For an individual oligopolist the quantity of product which it is capable of selling at any given price is dependent on the price charged by its competitors, which in turn is affected by the price set by the individual oligopolist in the first instance (Fellner, 1949, p. 11).

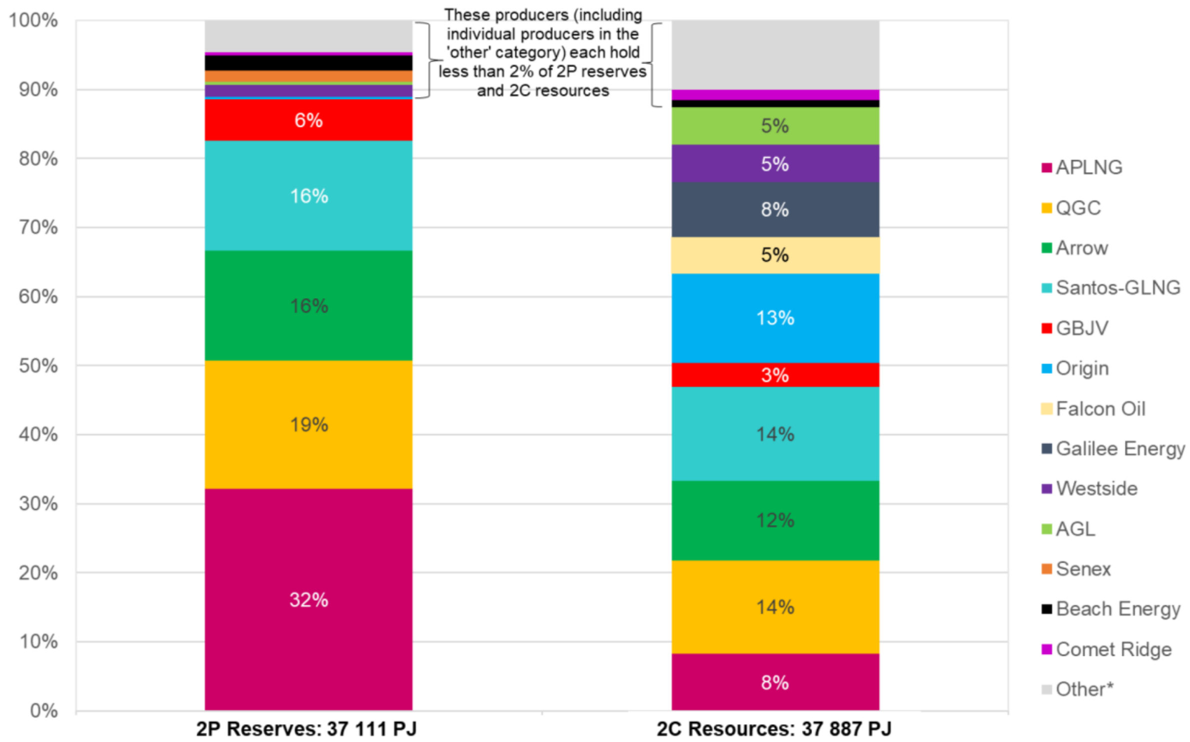
A number of theories of oligopoly predict that once firms recognise their interdependency, their most rational course of action would be to behave in a manner reminiscent of a monopoly. The outcome from these models has been described as tacit collusion, also known as conscious parallelism. Even where oligopolistic firms may not be part of a formal cartel arrangement that are seeking to collude by cutting back on production and raising prices, they may still be able to coordinate their conduct so that an outcome similar to a cartel or monopoly is achieved.[21]

The available evidence suggests the production of gas in the Eastern Gas Region is best characterised as an oligopoly with a competitive fringe based on 2P reserves. Over 80 per cent of 2P reserves are currently held by the Queensland LNG projects, either through ownership or through gas purchases from other related entities (Australian Competition and Consumer Commission, 2020, p. 35). APLNG holds the greatest share (32 per cent), QGC holds the second highest share (19 per cent) and has also acquired the bulk of Arrow Energy’s 2P reserves (16 per cent), while Santos-GLNG controls the third highest share (16 per cent). Amongst the other producers, the GBJV accounts for the greatest proportion of 2P reserves (6 per cent), followed by Beach Energy (2.2 per cent), Westside (1.8 per cent), Senex (1.6 per cent) and a range of other small to mid-tier producers (i.e. AGL, Armour Energy, Blue Energy, Central Petroleum, Cooper Energy, Macquarie Mereenie, Mitsui, OG Energy, Stanwell and Tri-Star). In addition, the Queensland LNG producers also currently hold around 47 per cent of 2C resources.

Details on 2P reserves and 2C resources held in the Eastern Gas Region is provided in Figure 16 below.

[21] A cartel is where there is a formal agreement amongst competing firms to collude to fix prices or cutback on production. The objective of a cartel is organise firms so they behave in manner similar to the outcome achieved by a monopoly. Within market economies, there are generally competition laws (also known as antitrust laws) prohibiting cartel arrangements.

Figure 16: 2P and 2C Resources held by Gas Producers in the Eastern Gas Region (at 30 June 2019)



Source: ACCC (2020, p. 36).
Note: QGC is owned by Shell that is part of the QCLNG project.

According to the UK Office of Fair Trading (2004, p. 11):

> *In general, market power is more likely to exist if an undertaking (or group of undertakings) has a persistently high market share.*[22]

However, just because a market is characterised as having an oligopoly structure does not necessarily mean that it will be prone to tacitly collusive behaviour. While market concentration can certainly provide guidance as to which markets are likely to raise competition concerns, it is certainly not a definitive determinate of anti-competitive behaviour.

Prominent industrial organisation economist Joseph Bain (1956) considered the force of potential competition as a regulator of price and output of comparable importance to that of actual competition and focused on the height of barriers to entry as the critical determinant of the price level. According to Bain, the extent of barriers to entry in an industry indicated the advantage that allowed existing sellers to raise their price over the competitive level without attracting new entry. Bain postulated that barriers to entry would have the greatest impact in oligopolistic markets where collective action would permit the deliberate elevation of prices to the extent allowed by barriers to entry.

According to the ACCC (2016, p. 61), barriers to entry into gas production are high:

> *… gas explorers and small new producers in particular face major challenges to achieve the scale necessary to enter the market for the wholesale supply of gas due to the cost and risks associated with gas production.*

[22] An undertaking covers any natural or legal person engaged in economic activity, regardless of its legal status (Office of Fair Trading, 2004, p. 2n).

> *Gas exploration and production have high capital costs, are high risk and have long project execution timeframes. Petroleum exploration and production permits, whether offshore or onshore, typically require work commitments such as seismic surveys and/or drilling wells. These investments tend to be sunk costs, where the investments have few alternative uses in the event that no gas is discovered. Exploration is also characterised as an activity with a low and uncertain probability of success.*

A number of features of gas production could dispose major producers towards tacit collusion and the exercise of market power:

- Market concentration on the selling side (Posner, 2001, p. 69). It is easier to coordinate a smaller number of firms.
- Standard (homogeneous) product (Posner, 2001, p. 75). Following processing, natural gas could be considered as a homogeneous product, thus minimising the scope for product differentiation and non-price competition and thereby providing a clear basis upon which a tacitly collusive agreement could be struck, namely the price of natural gas.
- Unconcentrated buying side of the market (Posner, 2001, p. 75). The incentive to break ranks from tacit collusion is lessened when the number of customers per seller increases as the reward from doing so diminishes (Stigler, 1964).
- Price competition is more important than other forms of competition (Posner, 2001, p. 76). When cutting prices is the only way of winning business away from competitors, eliminating price competition will yield higher profits.
- It is more difficult to cartelise the market for a durable than a nondurable product (Posner, 2001, p. 76). In many durable-goods industries, used products are traded in decentralised secondary markets not directly controlled by the producer that provide a source of competition and a substitute for new products. On the other hand, nondurable goods, such as natural gas, provide no such opportunities.
- Similar cost structures and production processes (Posner, 2001, p. 77). The more alike the firms in a market are with respect to the structure of their costs and to their production methods, the easier it will be for them to engage in tacit collusion.

The prevailing market structure as well as the characteristics of natural gas lend support to the ACCC implication that the three Queensland LNG export projects are exercising market power. In turn, a level of tacit collusion may be underpinning current domestic pricing of the three Queensland LNG export projects.

For reasons already outlined above, the ACCC (2016, p. 67) has been more forthright in declaring that the GBJV holds significant market power:

> *… due to significant market changes since the ACCC last considered arrangements in 2010, the GBJV now holds significant market power in the southern states …*

Further adding to concerns the Queensland LNG export projects may be exercising market power, there are longstanding concerns that there has been hoarding of gas reserves. According to the Productivity Commission (2015, p. 55):

> *Some large industrial gas users have suggested that gas companies are hoarding reserves, rather than developing them for production.*

In its most recent gas inquiry report, the ACCC (2020, p. 40) has commented that a number of smaller gas producers have suggested that some LNG producers and their affiliates have made decisions to 'bank' or 'warehouse' gas by delaying the development of some fields in order to meet their own commercial priorities. According to the ACCC (2020, p. 40):

> *One small producer in Queensland, for example, stated that it is "being prevented from developing its current modest reserves and resources due to the adjacent permit holder… not progressing their existing government approved…projects, for apparently global strategic reasons". Another small producer stated that one of the main barriers to the commercial recovery of its 2C resources is that its joint venture partner, which is a larger producer, is "not motivated to pursue a larger development".*

While noting there may be legitimate reasons for larger producers wanting to bank' or 'warehouse' gas, the ACCC (2020, p. 40) has nonetheless raised the possibility that larger producers may be seeking to write down the level of their reserves in order to withhold supply to maintain or raise prices. In turn, the ACCC (2020, p. 40) has expressed the following concern:

> *… the ACCC is concerned that larger producers and LNG producers in particular may have the ability to delay the development of much needed new sources of supply to suit their commercial priorities at the expense of the domestic market.*

The raising of wholesale gas prices above the level of LNG netback prices does present a market opportunity for LNG imports into the Eastern Gas Region that poses a risk to the commercial viability of the NGP.

5.4.2 Price Competitiveness of LNG Imports.

There are a number of reasons why LNG imports might be competitive with pipeline imports from Queensland (Department of Industry, Innovation and Science, 2018, p. 100).

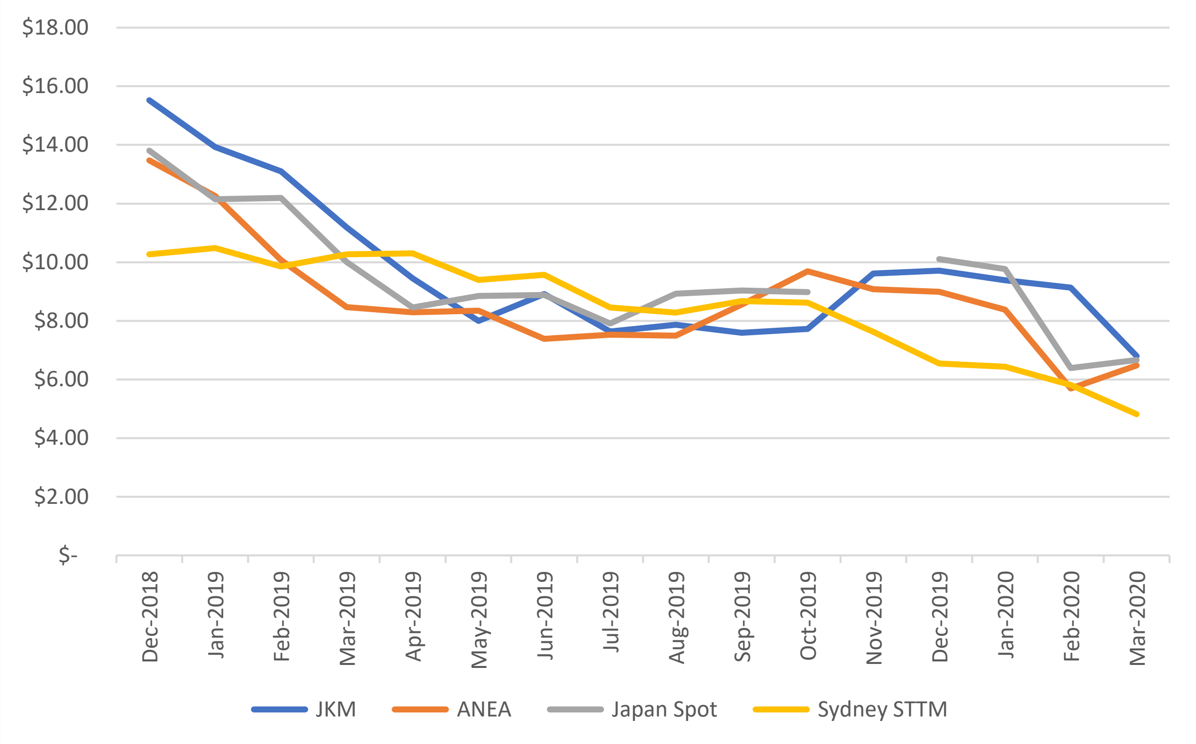
First, the cost of production in Queensland is relatively high (Department of Industry, Innovation and Science, 2018, p. 100). The vast majority of the gas produced in Queensland is CSG where production requires drilling hundreds of new wells per year — something that conventional gas production does not require — which adds to the cost of production. Gas in many other parts of the world — be it US shale gas or conventional gas in Qatar or off Australia's North West coast — has lower production costs.

Second, transporting gas via pipeline from Queensland to the southern states is relatively costly (Department of Industry, Innovation and Science, 2018, p. 100). The current published transmission costs from Wallumbilla to Sydney or to Culcairn for further transmission into Victoria is $2 per GJ (APA Group, 2020). On the other hand, it has been estimated that the costs per GJ of regasification for an FSRU importing up to 100 PJs per annum could be in range of between $0.60 - $1.50 per GJ (Department of Industry, Innovation and Science, 2018, p. 105).

It has been suggested that PKGT will source LNG from Australian oil and gas company Woodside as well as from the United States (2020). The sea freight voyage between Sabine Pass, the largest US LNG export terminal on the US Gulf Coast, and Tokyo, is comparable to the voyage between Sabine Pass and Port Kembla. On this basis, the JKM and similar Asian LNG spot price indicators provide reasonable proxies for the cost of importing LNG to Port Kembla. Other LNG spot price indicators include the Argus Northeast Asia 'delivered ex-ship' (des) (ANEA) (produced by Argus Media) that covers LNG spot prices for Japan, South Korea, Taiwan and China, as well as the Japanese Ministry of Economy, Trade and Industry (METI) contract LNG spot price landed in Japan.

Based on an imputed cost build-up of importing spot LNG cargoes to Port Kembla from December 2018 to March 2020 using the three LNG spot price indicators outlined above, and making allowances for the cost of regasification and pipeline transport to Sydney, it was found that during the six month period from April 2019 until September 2019 the imputed cost of regasified LNG exported to Sydney was cheaper than the average monthly Sydney STTM price on at least two of the three spot price indicators. This is outlined in Figure 17 below.

*Figure 17: Imputed Landed LNG Spot Price at Port Kembla, Regasified and Transported to Sydney and Average Sydney STTM Price – December 2018 to March 2020 (Aus$ per GJ)**



Sources: Platts LNG Daily, International Monetary Fund Primary Commodity Prices, Japanese Ministry of Economy, Trade and Industry contract-based LNG spot price, and Australian Energy Regulator Gas Weekly Reports, and Reserve Bank of Australia.
Note: Assumed cost of regasification of $1.20 per GJ based on Department of Industry, Innovation and Science (2018, p. 105), and an assumed $0.25 per GJ to transport gas from Port Kembla to Sydney.

Also, since March 2019 an imputed cost build-up of importing spot LNG cargoes to Port Kembla and transporting the gas to Sydney has been competitive against the cost of delivered gas from the NGP of somewhere in the order of $7.60 to $8.40 per GJ to Sydney. With an imputed cost build-up of less than $7 per GJ for LNG gas delivered to Sydney in March 2020, assertions that gas from NGP will "always be cheaper than LNG imports" is simply hubris.

Arguably, the PKGT is competing directly against the NGP for commercial viability with only one project likely to proceed. Whichever project proceeds will depend on whoever is able to secure more long-term supply agreements before a final investment decision (FID) is taken.

This analysis suggests the development of an LNG import terminal could be commercially viable in NSW, adding further risk to the development of the NGP.

6. Timeliness of the Narrabri Gas Project

Even if Santos is granted planning approval to proceed with the NGP, there is no guarantee that it would proceed to a final investment decision any time soon.

As discussed above, there have been longstanding concerns expressed that the Queensland LNG export projects have been hoarding, banking and warehousing CSG gas reserves, perhaps in order to maintain tacitly collusive gas pricing. As a part owner in one of the Queensland LNG export projects, presumably Santos is subject to the same incentives as the other operators and affiliates.

Furthermore, given current pressures on international and domestic oil and gas prices, Santos would be unlikely to commit the capital investment of $3.57 billion that is required for the development of the NGP, let alone the ongoing project operating costs of $5.47 billion over 25 years.[23] In March 2020 Santos (2020c) announced in its response to COVID-19 and a lower oil price environment that it would be reducing capital expenditure by $550 million during 2020, as well as deferring a final investment decision on its Barossa project, a gas and light natural gas liquids field located offshore about 300 kilometres north of Darwin.

7. Conclusions

Recent market developments raise increasing questions about the competitiveness of gas produced by the NGP.

There is a significant risk posed to the commercial viability of the NGP from any renegotiation of long-term export contracts for Queensland LNG export project arising from the gap that has opened up between Asian LNG spot prices and long-term oil linked contract prices. The available evidence suggests that the gap between Asian LNG spot prices and long-term oil linked contract prices is likely to persist. Should this occur, there is a likelihood that Queensland CSG could be redirected back into the domestic market and the Eastern Gas Region, thereby eroding the market justification for the NGP.

Despite claims to the contrary, LNG imports into the Eastern Gas Region can be price competitive with, if not undercut, gas produced and transported to Sydney from the NGP. There is evidence that gas prices in the Eastern Gas region are higher than they should be. This raises a market opportunity for LNG imports into the Eastern Gas Region that poses a risk to the commercial viability of the NGP.

Arguably, the PKGT is competing directly against the NGP for commercial viability with only one project likely to proceed. Whichever project proceeds will depend on whoever is able to secure more long-term supply agreements before a final investment decision is taken.

Even if Santos is granted planning approval to proceed with the NGP, there is no guarantee that it would proceed to a final investment decision any time soon. There have been longstanding concerns expressed that the Queensland LNG export projects, of which Santos is a part, have been hoarding, banking and warehousing CSG gas reserves. In the current environment when it has been cutting back on its capital expenditure deferring a final investment decision on its Barossa project, there is a material risk that Santos would be unlikely to commit the full capital investment of $3.57 billion for the development of the NGP, let alone the ongoing project operating costs of $5.47 billion over 25 years.

[23] See GHD (2016, p. 15).

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