

Chapter 2

Project rationale



2.1 Overview

This chapter describes the status of gas supply and demand on the east coast of Australia and the rationale for the Gas Import Jetty and Pipeline Project (the Project) in the context of energy security, efficiency and affordability.

The chapter considers the need for the Project in the context of:

- production declines leading to supply shortfalls
- regional supply and demand imbalances
- pipeline infrastructure constraints
- transition to renewable energy.

This chapter is also intended to provide background to the site selection process, including:

- an overview of the LNG import options considered during the development of the Gas Import Jetty Works, including an explanation of the floating storage and regasification (FSRU) approach in preference to a land-based alternative, and a rationale for selecting the proposed site at Crib Point (see **Section 2.5**).
- an explanation of the selection process for the pipeline alignment, including gas pipeline options considered as part of the development of the Pipeline Works (see **Section 2.5.3**).

The aim of the Project is to meet the needs of industrial, commercial and residential gas customers on the east coast of Australia against a backdrop of predicted gas shortfalls in the south-eastern Australian states from 2024 onwards.

The Project is part of AGL's commitment to deliver gas supply certainty to the south-eastern Australian market safely, within agreed timeframes and at competitive prices, while balancing economic, social and environmental factors.

The abundant gas supplies Victoria has enjoyed since the 1960s are in decline, particularly from the Gippsland Basin fields in Bass Strait. This means that Victoria needs to find alternative sources of gas supply. While Australia is a major exporter of natural gas, most is produced in locations extended distances from demand centres and is not available to customers in the south-eastern states.

The interconnected nature of gas and electricity markets on the eastern seaboard means the Project would benefit and provide energy security to Victoria as well as other south-eastern states and the national economy more broadly.

The Project would assist in Victoria's transition to a low-carbon economy and increased energy efficiency (including reduced usage). The Project would contribute to the foundation for maintaining energy security to support the state's growth and development. Liquefied natural gas (LNG) imports offers a flexible option of short and long-term energy supply to provide a secure, stable source of supply to customers as the energy sector becomes decarbonised and transitions to more renewables.

2.2 East coast gas production and Project need

The Project is necessary to fill the shortfall in gas supply predicted from 2024 and to support essential energy supply to enable Victoria's energy security and continued economic development.

The Project provides a viable and flexible solution with proven technology and, as described in **Section 2.5**, the selected site already contains major maritime infrastructure and provides optimal flexibility to meet demand and adjust to market requirements.

The Victorian economy is highly dependent on gas. Victoria's gas-intensive manufacturing sector and its cold winters mean the state accounts approximately 50 per cent of gas demand in south-eastern Australia.

Victoria, New South Wales and South Australia (the south-eastern states) have historically received much of their gas from Victoria's offshore Gippsland and Otway basins in Bass Strait. These mature southern gas reserves are facing declining production, which will reduce gas availability in Victoria and limit gas exports to New South Wales and South Australia.

Reduced production from the southern reserves will mean greater reliance on gas from northern reserves in Queensland but their ability to supply the southern states is limited by pipeline infrastructure capacity and cost constraints.

Even if the gas could be physically transported to the southern states cost effectively, the bulk of the gas production from Queensland is already committed to LNG export contracts. Other sources of gas production in Western Australia are not directly available to south-eastern customers due to the absence of pipeline infrastructure connecting the east coast network.

The Australian Energy Market Operator (AEMO) advised in its 2020 Gas Statement of Opportunities (AEMO, 2020, p. 3¹) that:

Supply from existing and committed gas developments will be sufficient to meet forecast gas demand across eastern and south-eastern Australia until at least 2023, provided that liquefied natural gas (LNG) export spot cargoes are redirected to meet domestic demand, if required.

Several gas fields are forecast to cease production sometime between mid-2023 and mid-2024. If production ceases earlier, this could create peak winter day supply gaps in Victoria in 2023.

Southern supply from existing and committed gas developments will reduce by more than 35% (163 petajoules [PJ]) over the next five years, despite an increase in committed gas developments in the past year. 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.

Anticipated gas field projects (considered likely to proceed within the outlook period) are forecast to improve resource adequacy until at least 2026 if developed. However, due to the location of most of the anticipated projects within Victoria, dynamic operational pipeline constraints would limit their effectiveness in addressing the forecast peak winter day supply gaps under certain conditions.

1 https://aemo.com.au/-/media/files/gas/national_planning_and_forecasting/gsoo/2020/2020-gas-statement-of-opportunities.pdf?la=en

2.2.1 Gas demand and availability of reserves

Gas is an important natural resource for households, businesses and industries.

Domestic demand for gas in eastern Australia is derived from three sources:

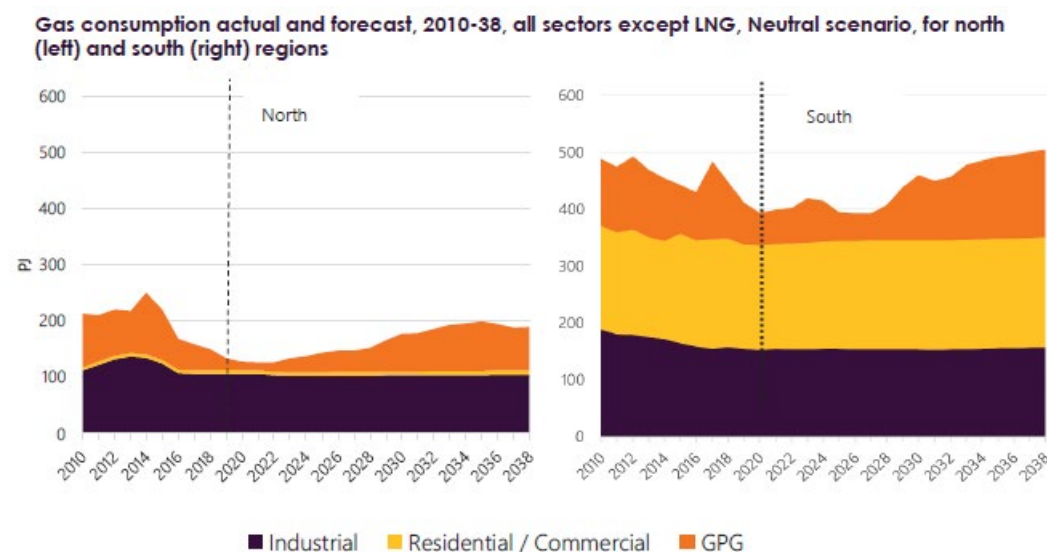
- commercial and industrial gas users (around 41 per cent of domestic demand)
- gas-powered generators (29 per cent)
- residential customers (29 per cent).

As identified by the Australian Energy Regulator (AER) in its 2018 State of the Energy Market report, with the commissioning of three separate new LNG export projects in Queensland in 2015, international customers became the largest source of demand. In round figures, the demand for gas from the Queensland LNG export projects is roughly double the rest of the east coast demand combined.

Although, the forward domestic gas demand (mid case) forecast by the AEMO remains relatively flat overall, the most significant demand increase for gas comes from the Queensland LNG export projects. These projects were originally anticipated to source their gas requirements from their own reserves in the Surat-Bowen Basin. However, development of upstream reserves such as the Gladstone LNG (GLNG) project has proven lower than expected, resulting in the sourcing of gas from other producers. In its June 2019 Energy Quarterly, consultancy EnergyQuest reported that in the March quarter of 2019, the GLNG project produced approximately 48 per cent of the LNG from gas reserves within its portfolio. Fourteen per cent was produced elsewhere in project partner portfolios and third parties provided the balance. This puts increasing pressure on the demand for domestic gas.

Gas demand in Victoria is primarily driven by the residential and commercial sectors while in Queensland these sectors comprise a very small percentage of total gas consumption.

Figure 2-1 shows the geographic variance of gas use for each customer sector (industrial, residential/commercial and gas-powered generation [GPG]) between the warmer northern states of Queensland and the Northern Territory and the southern states of Victoria, New South Wales and South Australia.



▲ **Figure 2-1:** Gas consumption actual and forecast, 2010 to 2038, all sectors, neutral scenario, by north and south regions
Source: Victorian Gas Planning Report Update; AEMO, 2019

The AEMO March 2020 Gas Statement of Opportunities identified that residential and commercial sector gas consumption is projected to grow modestly from 191 PJ in 2020 to 205 PJ in 2039. Demand from the gas-powered generation sector saw an increase in 2017 following the retirement of the coal-fired Hazelwood Power Station in March 2017 and extended coal outages of Yallourn and Loy Yang coal-fired power stations. However, consumption from the gas-powered generation sector is forecast to decrease from recent historical levels until approximately 2029 as new renewable electricity generators are installed in the National Electricity Market (NEM), and then increase post 2029 as coal fired generators are retired from the NEM.

Figure 2-2 shows the AEMO's forecast of the expected production forecast if existing, committed, and anticipated projects are available to add supply to the market in the long term². The 2P reserves shown in the figure (Developed and Undeveloped) are the sum of proved and probable gas reserve estimates. The 2P Developed reserves include gas accessible from existing production wells. The 2P Undeveloped reserves are gas reserves expected to be supplied from wells yet to be drilled. In previous publications AEMO has shown the supply gap identified in this Figure being fulfilled by contingent resources, namely those quantities of gas estimated to be recoverable from known accumulations using established technology but which are currently considered uncommercial due to one or more uncertainties (such as excessive cost to recover) as well as prospective resources, gas volumes estimated to be potentially recoverable from undiscovered accumulations.

Development of more uncertain reserves and resources will be required across eastern and south-eastern Australia to ensure demand is met to the end of the outlook period. There is a risk that anticipated projects, while having a reasonable expectation of progressing to production, in fact may not progress. To understand this risk, AEMO undertook the above GSOO analysis assuming only committed projects proceed. Victoria's gas demand is approximately 200 PJ per annum and with the forecast decline in production from the offshore Gippsland, Bass and Otway basins, the AEMO estimates of supply and demand for gas on the east coast of Australia as shown in **Figure 2-2** below highlight the importance of the development of alternate supply sources such as contingent resources; namely resources currently considered uncommercial or through gas importation.

Recent unsuccessful drilling campaigns in the Victorian offshore basins have shown that it is increasingly challenging to identify new resources. The distance and high mobilisation costs to bring drilling rigs to the region are additional impediments to development.

With dwindling production from the southern basins and the recent unsuccessful drilling campaigns, alternative gas supplies are required to meet domestic demand for south eastern Australia.

Table 2-1: 1 Evaluation objectives

	2P Developed reserves	2P Undeveloped reserves	2C Contingent resources
2019 GSOO	12,830 PJ	29,803 PJ	58,263 PJ
2020 GSOO	15,030 PJ	22,303 PJ	59,600 PJ

² https://aemo.com.au/-/media/files/gas/national_planning_and_forecasting/gsoo/2020/2020-gas-statement-of-opportunities.pdf?la=en Page 9

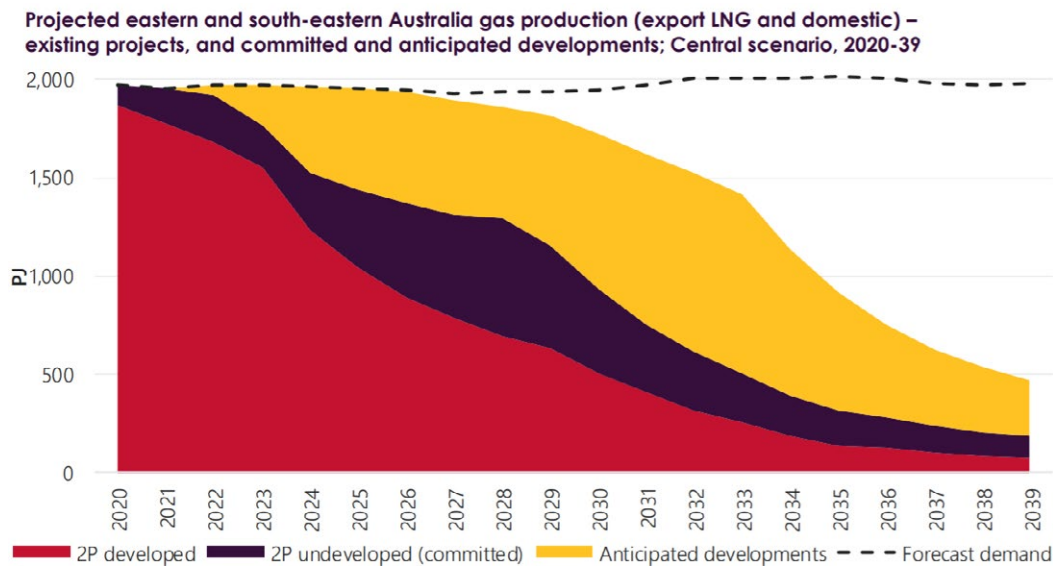


Figure 2-2:

AEMO forecast and status of southern resources to meet southern demand 2020–2039

Source: Victorian Gas Planning Report Update; AEMO, 2019

2.2.2 Lack of success in gas exploration

The AEMO March 2020 Gas Statement of Opportunities report shows many of the supply sources that AGL has relied on to meet customer needs are in decline. Furthermore, as shown in **Figure 2-2** above, AEMO has highlighted that current proven and probable reserves are insufficient and future production is reliant on contingent and prospective resources that have yet to be proven technically or commercially viable.

In the year between the release of AEMO's 2019 and 2020 Gas Statement of Opportunities reports, while 2P Developed reserves increased this was more than offset by the drop in 2P Undeveloped reserves, as shown in **Table 2-1**. The result across the three categories was a decline in reserves and resources estimates of 3,963 PJ.

In its Gas inquiry 2017–2020 Interim Report (January 2020), the Australian Competition and Consumer Commission (ACCC) highlighted a concern about the decline in 2P reserves that has occurred between 30 June 2017 and 30 June 2019, particularly given that most of the decline has occurred in Queensland, which the East Coast Gas Market has become increasingly reliant upon.

In particular the ACCC emphasised a concern about the reserves downgrade and other downward revisions that have occurred in Queensland over this period, with over 5,700 PJ of 2P reserves in the Bowen and Surat basins written down.

EnergyQuest noted that this trend is, at odds with the assumed progression of resources, which is that under the right market conditions contingent resources (or a portion thereof) become commercially viable to develop and are reclassified as reserves. The opposite, however, seems to be true in Queensland, with reserves that were previously found to be commercially viable to develop no longer being found to be so even though domestic gas prices had increased in the intervening period³. The recent trend, with short term prices declining, adds additional uncertainty to these resources becoming commercially viable.

³ EnergyQuest: Energy Quarterly March 2019.

The AEMO March 2020 Victorian Gas Planning report (VGPR) (p. 3)⁴ states:

Committed annual gas supply forecasts provided to AEMO by Victorian gas producers have increased by approximately 10% for 2020-23 compared to the 2019 VGPR, due to some anticipated projects progressing into committed projects. Despite the near-term increase in forecasts, committed supply is forecast to reduce by 37% from 2022 to 2024 due to field decline.

Without additional gas supply, removal of pipeline constraints, or a liquefied natural gas (LNG) import terminal, gas supply restrictions and curtailment may be necessary from 2024.

While the peak day supply forecasts provided to AEMO by gas producers have increased slightly for 2022 and 2023 since the publication of the 2019 VGPR, there is a significant reduction in 2024 due to a key Gippsland gas field and several smaller gas fields being forecast to cease production sometime between mid-2023 and mid-2024.

The forecast Victorian supply shortfall for a 1-in-2 year peak system demand day during winter 2024 is 27 terajoules (TJ), while the forecast shortfall on a 1-in-20 year peak day is 153 TJ. System demand does not include gas for gas-powered generation (GPG) of electricity, which peaked at 242 TJ a day (TJ/day) during winter 2019. There are several anticipated projects (projects considered reasonably likely to proceed during the outlook period) which could improve the annual supply balance. The majority of these projects are located in the Otway Basin, which would be constrained by the capacity of the South West Pipeline (SWP), hence forecast peak day supply issues would not be resolved without an expansion of the SWP.

Resolving forecast peak day shortfalls will require the progression of potential projects (currently not considered likely to proceed during the outlook period), the expansion of pipelines for importing additional gas supply, or an LNG import terminal.

Figure 2-3 indicates that in comparison to the 2019 VGPR, annual production forecasts provided by producers have increased from 2020 to 2023 due to increased Gippsland production output over the outlook period but there is a large reduction in available Gippsland production forecast in 2024 lowering the available Gippsland supply forecast from 260 PJ in 2023 to 201 PJ in 2024. (Most of Gippsland's gas was contained in three fields: Marlin, Barracouta, and Snapper. The steep decline in forecast production in 2024 is driven by one of the key Gippsland Basin Joint Venture (JV) fields being forecast to reach end of life.⁵)

Anticipated supply shown in **Figure 2-3** includes the uncommitted supply that is considered likely to be brought online from 2020 onwards. AEMO notes however, that no new projects have progressed into the anticipated category since the 2019 VGPR to backfill the projects that have advanced into committed projects. The ACCC also found that undeveloped gas reserves are "increasingly dependent on more speculative sources of supply"⁶. Furthermore, while Victoria is expected to produce sufficient gas to cover its own consumption until 2023, the ability to export to South Australia and New South Wales will decline over the next few years. Beyond this date, the ability of Victoria to cover its own demand and support the requirements of neighbouring states is highly reliant on prospective projects.

⁴ https://aemo.com.au/-/media/files/gas/national_planning_and_forecasting/vgpr/2020/2020-vgpr-update.pdf?la=en

⁵ Victorian Gas Planning Report Update. March 2020

⁶ ACCC, Gas Inquiry 2017-2025 Interim Report, January 2020 at <https://www.accc.gov.au/system/files/Gas%20inquiry%20-%20January%202020%20interim%20report.pdf>

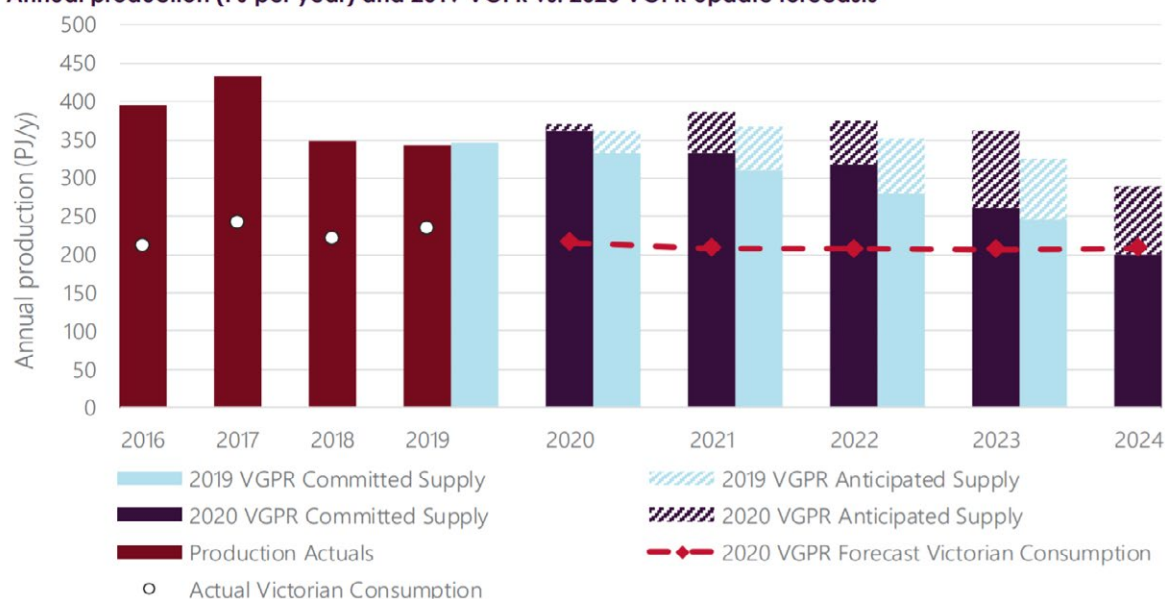
Annual production (PJ per year) and 2019 VGPR vs. 2020 VGPR Update forecasts

Figure 2-3: Annual production (PJ per year) by location in Victoria
 Source: Victorian Gas Planning Report Update; AEMO, 2020

The Bloomberg New Energy Finance report on 19 December 2018 highlighted that investment in new gas fields needs to be made years beforehand to meet the looming shortages:

Continued investment in exploration depends on oil prices, which increases the uncertainty in predicting the commercial start-up of new gas fields. Decline in oil prices post 2014 led to a sharp reduction in spending on exploration activities since domestic gas contracts also use oil price as the index to calculate the gas price.

Lower spending on the upstream sector is a signal of possible delays in bringing the undeveloped and contingent resources online.

Development of domestic gas resources is highly dependent on oil prices and other commercial and technical considerations, which can add uncertainty and delay the start-up of new gas production. The economic impacts of COVID-19 and extent of the knock-on effects to oil and exploration budgets are yet to be fully understood but any deferral of investment in exploration has the potential to delay new sources of production. The chief executive of the Australian Petroleum Production & Exploration Association (APPEA) noted that “current economic conditions have the potential to irreparably damage oil and gas exploration in Australia unless steps are taken to provide short term relief to allow companies to remain in business until the economy has moved through the worst of the downturn.”

According to ExxonMobil, one of the Gippsland Basin’s large legacy fields has depleted earlier than expected with another two fields expected to be depleted in the early 2020s⁷. Identification of viable new southern reserves in the Gippsland basin are proving highly challenging, as illustrated by the recent drilling by ExxonMobil of the Baldfish and Hairtail wells within the Dory prospect. Initially thought to have the potential to be one of the largest untapped gas resources in Victoria. After several months and \$120 million in drilling expenditure, The Australian newspaper reported in November 2018 that no commercial levels of hydrocarbons had been encountered and in September 2019 the company announced that it was investigating options for a sale of all of its Gippsland Basin oil and gas assets.

⁷ <www.appeaconference.com.au/the-voice-richard-owen-exxonmobil-australia>

2.2.3 Forecast supply shortages

AGL relies on procuring competitively-priced gas from producers to meet its retail and wholesale needs. Historically, AGL has sourced its gas supply from the upstream producers with gas production projects in the Gippsland and Otway basins (Victoria), the Surat-Bowen Basin (Queensland) and Cooper and Eromanga basins (South Australia and Queensland).

AGL markets around 180 PJ to the Australian gas market each year. AGL has a small portfolio of natural gas assets at Camden in New South Wales, which only supplies about 4 PJ per annum. Approximately 10 PJ per annum is sourced from the AGL Gas Storage Facility at Silver Springs in Queensland. The majority of the 180 PJ of gas required to supply AGL customers is therefore procured from various other gas producers in Australia.

The March 2020 *Victorian Gas Planning Report* (AEMO, 2020) highlighted that producers have advised that total Victorian winter production will reduce from 1,214 TJ/day in 2020 to 631 TJ/day by 2024⁸. EnergyQuest noted in its March 2020 quarterly report Victoria's gas demand over winter nearly triples in comparison with summer levels. The south-eastern states go from a 600 TJ/day environment to a 1500-2000TJ/day requirement in winter. The Victorian Gas Planning Report Update (Mar 2020) shows that that large reduction expected in 2024 is due to several fields being forecast to cease production across 2023 and 2024. This includes advice from Esso Australia Resources that another of the key Gippsland Basin fields (processed by the Longford Gas Plant) is forecast to cease production during this period but if offshore fields deplete earlier than forecast, there is a risk of insufficient peak day supply and the curtailment of GPG during winter 2023.

ExxonMobil, the operator of the Gippsland Basin JV, described 2018 as a turning point. Chairman and Lead Country Manager Richard Owen stated in February 2019 that the broader community has come to appreciate the importance of gas to our economy and has finally realised the cheap supplies we have relied on for half a century have run out.⁹

Shortfalls in domestic gas supply are likely to result in higher and more volatile gas prices for Australian customers and place increasing pressure on the ongoing viability of many industrial customers. AEMO has identified that supply constraints leading to high gas prices may lead to price driven demand destruction, particularly for vulnerable large industrial loads, which are often major sources of employment.

For gas supply from Queensland to be a viable alternative for the southern states, pipeline constraints would need to be addressed and Queensland's production increased. However, previous AEMO reports (AEMO 2019) have advised that while drilling rates in coal seam gas (CSG) fields by gas producers in Queensland continue to increase, production rates are holding steady, or only increasing at a slower rate. Increasing the amount of investment in new gas developments is required just to maintain the same amount of production, before any consideration of filling the supply gap of the south-eastern states. Unless new sources of gas are discovered, this trend will unlikely change.

Also, gas supplies from Western Australia's north-west shelf are not available to Victoria as no pipeline links the north-west of Australia to the south-east and the cost of developing such a concept has proven prohibitive. A report commissioned by the Department of Energy found the West-East Pipeline would cost more than \$5 billion and does not appear to be the best or most economical option for dealing with the supply issues currently facing eastern Australia¹⁰.

The combination of the factors described above mean that a shortfall of gas supply in south-eastern Australia is looming. Gas supplies from alternative sources are vital to maintain security, stability and affordability of gas supply to households and industry.

⁸ Victorian Gas Planning Report Update. March 2020

⁹ <www.appeaconference.com.au/the-voice-richard-owen-exxonmobil-australia>

¹⁰ <www.energy.gov.au/sites/default/files/west-east_gas_pipeline_pre-feasibility_study_pdf_6805kb.pdf>

2.2.4 Regional imbalances

The large size of Australia means that its largest south-eastern population centres are not connected to the gas reserves or LNG production plants in the north-west.

South-eastern states are connected to some supply from Queensland and, with the addition of the more recent Northern Gas Pipeline, to gas reserves in the Northern Territory but the distances are vast, capacity is constrained and transport costs are high.

Figure 2-4 shows an overview of 2P (proven plus probable) gas reserves by basin.

Ideally, a new local supply will meet demand in the south-east and avoid pipeline constraints. The history of oil and gas exploration in Victoria and recent exploration drilling results suggest that new supply sources to fill the shortfall will not be discovered in the foreseeable future in the southern states. Due to the depletion of reserves offshore in Victoria and the development of coal seam gas reserves in Queensland, the Gippsland Basin now only accounts for around five per cent of eastern Australian reserves, with an estimated 2272 PJ of 2P (AER, 2018).

Figure 2-5 highlights (in yellow) the location of demand centres in the most densely populated and colder south-eastern states compared with the location of the most abundant gas reserves serving LNG export facilities in the north-west and north-east of the country.

Figure 2-6 shows that Victoria's demand for gas is significantly higher than New South Wales and South Australia combined.

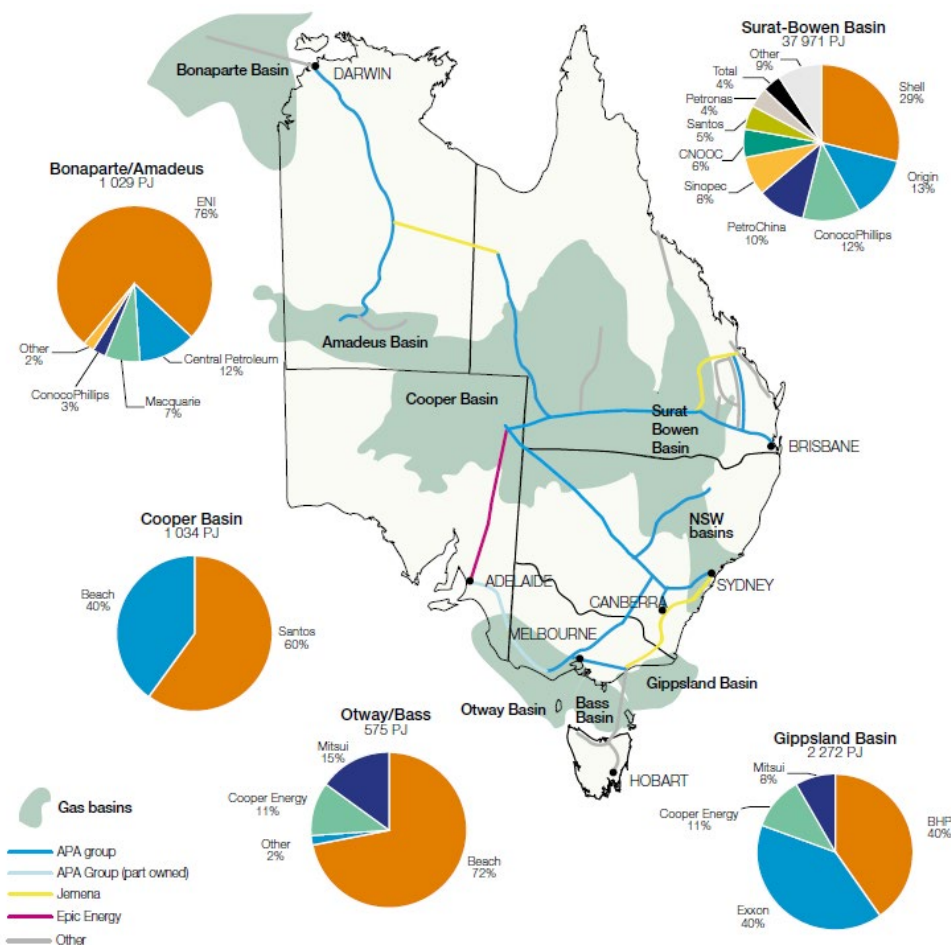
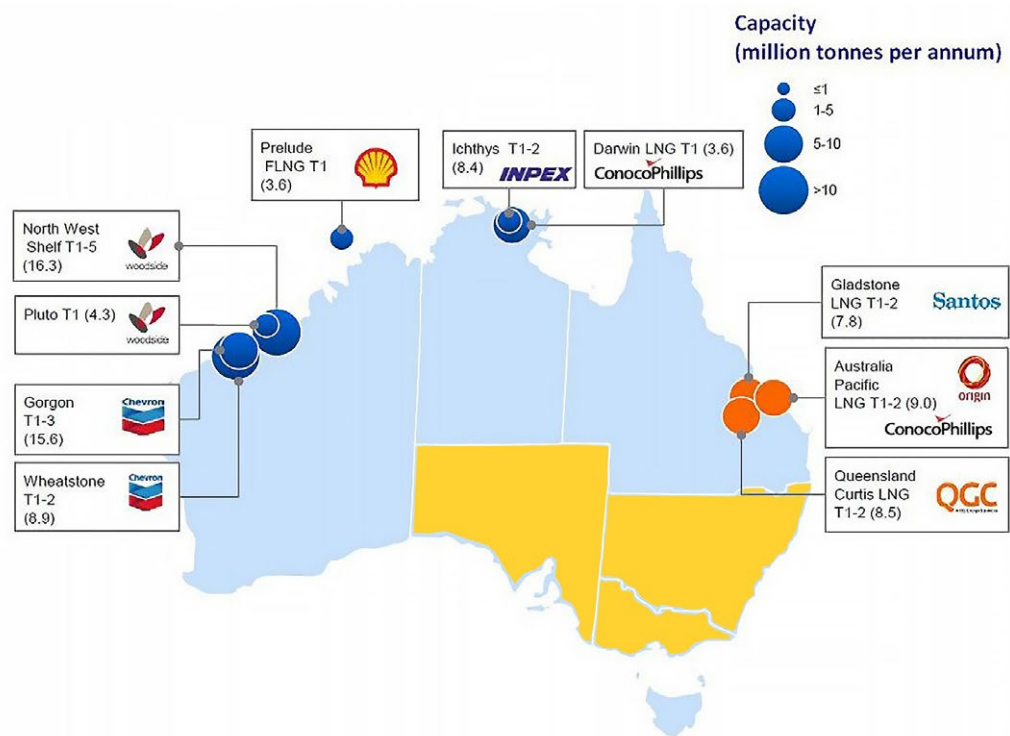


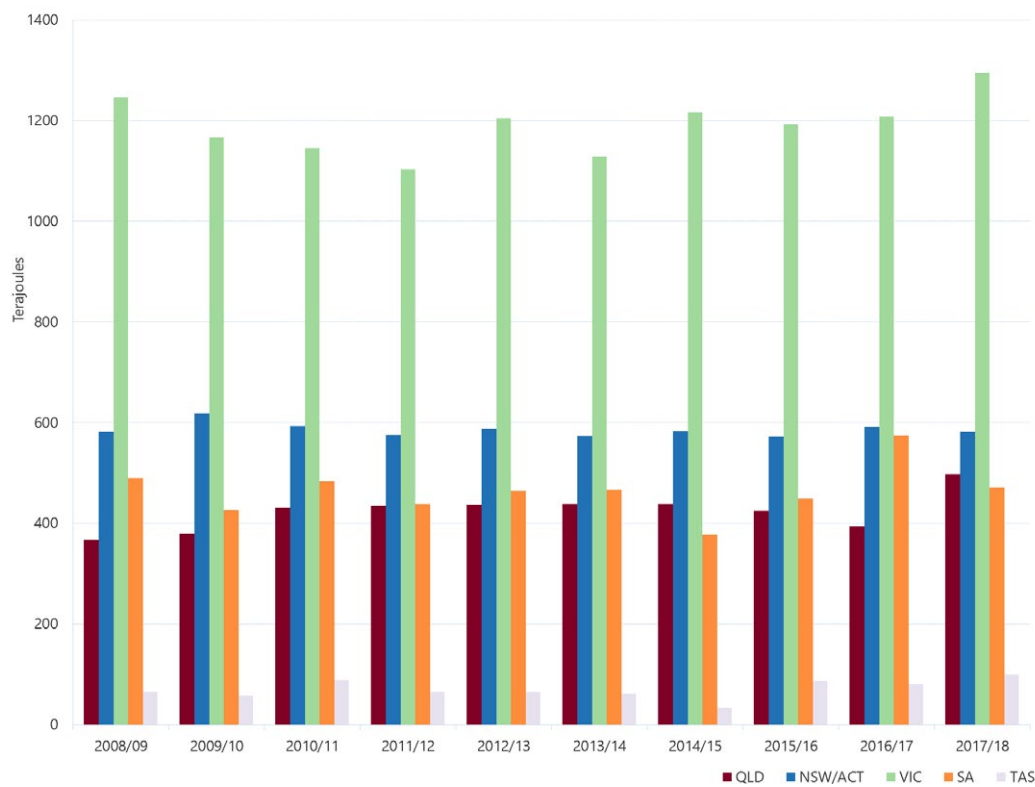
Figure 2-4: AER overview of 2P (proven plus probable) gas reserves by basin shows their gas reserves estimates for the east coast and Northern Territory

Source: State of the Energy Market 2018; AER, 2018

Notes: Ownership at 30 June 2018. Pie charts illustrate shares in 2P (proven plus probable) gas reserves by basin.
Sources: AER; EnergyQuest (data commissioned by AER).



▲ **Figure 2-5:** Demand centres vs major gas reserves locations
Source: <oilprice.com>



▲ **Figure 2-6:** Domestic demand on a state-by-state-basis, excluding Queensland LNG
Source: AER, AEMO

Figure 2-7 shows the historical supply and demand duration curve and sources of domestic gas supply to meet that demand from the south-eastern states in 2018 (excluding supply to the Queensland LNG export projects). The figure highlights the importance of Victoria's gas supply (shown in red) in satisfying demand in the south-eastern states as well as the need for a supplemental source of gas supply, which the South West Queensland Pipeline (SWQP) currently meets, often at its maximum capacity.

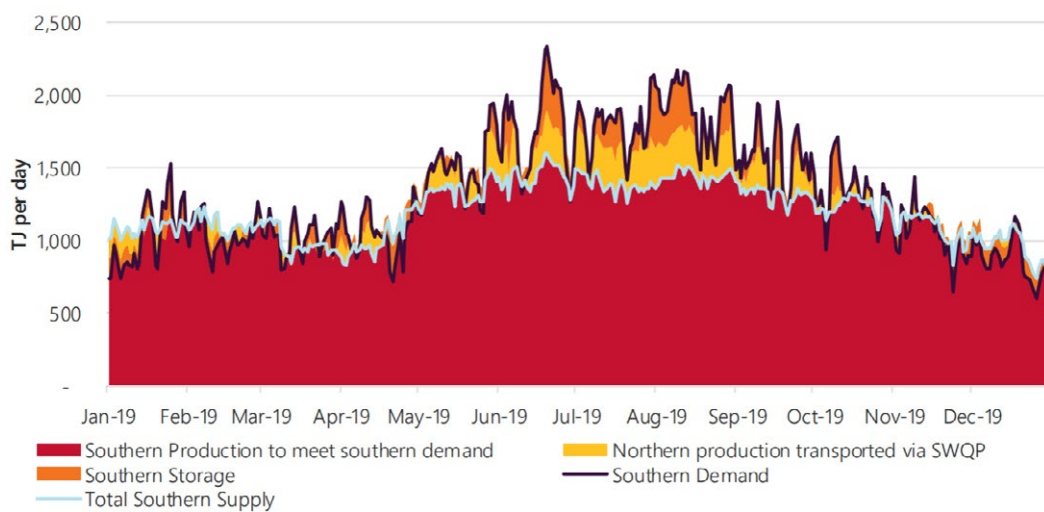


Figure 2-7: Historical actual daily supply and demand balance in the southern states, 2019
Source: Gas Statement of Opportunities report; AEMO, 2019



Source: Gas Bulletin Board (GBB)



Figure 2-8: Total flows along the SWQP from 1 January 2016 to 31 December 2019

Figure 2-8 shows the trend for average gas flows between north and south. In 2016 gas flow were almost exclusively north towards Queensland due to ample supplies in the south and the appetite for gas from the Queensland LNG export projects. However, a marked shift has occurred in the last few years with gas transported towards the south-eastern states on over 70 per cent of days in 2019, compared to fewer than 10 per cent of days in 2016. The quantity of gas transported south has also increased, with gas transported south exceeding 200 TJ on approximately 25 per cent of days in 2019, compared to fewer than 10 per cent of days in 2018. While the need for gas to be transported to the south to replace declining local production increases, the ability to deliver has to the southern markets is limited by pipeline capacity.

2.2.5 Shortfalls result in higher prices

Before 2015, gas supply on Australia's east coast was characterised by an abundance of accessible supply and comparatively low, stable pricing, and was largely isolated from international gas markets. Prices for gas that was often extracted as a by-product of crude oil production were considered low by international standards and were negotiated on a bilateral basis at a fixed price plus Consumer Price Index (CPI). The pre-LNG era in eastern Australia is often viewed as a time of assured supply, low gas prices, flexible contractual terms and long-term bilateral contracts.

The development of the Queensland LNG export industry allowed resource developers to access international markets and has transformed the supply-demand dynamics in south-eastern Australia, with increased demand for gas from international markets causing domestic market prices to increase. As a result, gas contracting timeframes have shortened (often to less than three to five years), prices have increased and contractual flexibility for buyers has reduced. Combined with declining gas production from southern reserves, this has resulted in higher and more volatile prices for Australian customers, reflecting competition for scarcer domestic gas supplies.

The ACCC Gas inquiry 2017–2020 Interim Report (April 2018)¹¹ examined prices that gas buyers in the East Coast Gas Market paid to gas producers in the Surat/Bowen (QLD), Cooper (SA) and Bass Strait (Vic) basins from the 2015 to 2017 calendar years as shown in Figure 2-9. The report concluded that following the increase in demand, prices paid in each region increased across the period, with the largest relative increase of 45 per cent in the Bowen/Surat (QLD) basin as LNG production at the Queensland ramped up. Although the average price paid across the entire east coast increased over the period by 23 per cent, the average increases are dampened by a number of legacy gas sales agreement agreed on when market conditions were substantially different. Prices from more recent gas sales agreements entered into since January 2016 by Queensland producers have been separately marked on the chart. At the end of 2017, the average price paid under these recent contracts was \$8.62 per gigajoule (GJ), which represents a 67 per cent difference compared with the average price paid to all producers across the east coast.

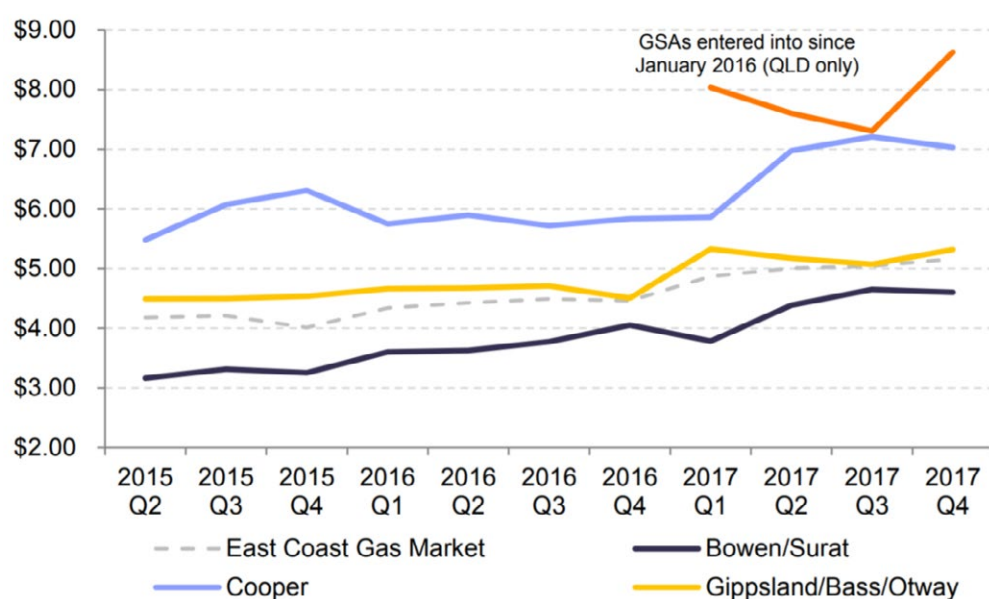


Figure 2-9: Average gas commodity price invoiced by producers; A\$ nominal/GJ
Source: ACCC

¹¹ <www.accc.gov.au/publications/serial-publications/gas-inquiry-2017-2020/gas-inquiry-april-2018-interim-report>

The ACCC April 2019¹² Gas Inquiry 2017-20 Interim Report highlighted that domestic prices remain too high for many gas users and that further investment in gas exploration and development as well as key infrastructure is required to guarantee security of supply and sustainable prices for east coast domestic gas customers. Data from EnergyQuest supports the ACCC findings, showing domestic gas prices jumped by up to 51 per cent in Melbourne from December 2017 to December 2018, with Sydney rising 45 per cent, Brisbane climbing 32 per cent and Adelaide 31 per cent.

In its January 2020 update to the Gas Inquiry 2017-20 Interim Report¹³, the ACCC noted that over the course of 2019, prices offered by gas producers for 2020 supply largely remained steady within the range of \$9–10/GJ, while prices offered by retailers to C&I users in the Southern States were in the \$8–12/GJ range, constituting a slight downward shift in prices between March and August 2019. After reaching a peak of almost \$11/GJ in October 2018, expected 2020 LNG netback prices at Wallumbilla trended downwards over the course of 2019 and by the end of August were around \$7.50/GJ.

When the ACCC December 2018 Gas Inquiry 2017-20 Interim Report was published, its Chair Rod Sims stated in an ACCC media release statement released 18 December 2018¹⁴:

Some commercial and industrial gas users have told us that, at these prices, which are two to three times higher than historical prices, their operations are not sustainable in the medium to longer term. They are increasingly likely to relocate from the east coast or close their operations.

Gas is a raw material to production or largely irreplaceable source of energy for a diverse range of sectors such as mining, manufacturing, chemicals, agriculture and food production. Rising domestic gas prices are putting gas users which are exposed to global markets under strain, as they cannot pass on the increases in their costs.

Once large manufacturers relocate or shut down their plants, they won't come back. ...

The timing of the development of uncontracted proved and probable reserves is critical for the east coast gas market.

The impact to Victorian spot gas prices when there is supply constraints can also be seen in market pricing. For example, in 2016 and 2017 a short-term tightening of supply to Victoria, which was otherwise well supplied, led to Victorian prices increasing to track the cost of the marginal supply from Queensland at LNG netback pricing plus transportation to Melbourne.

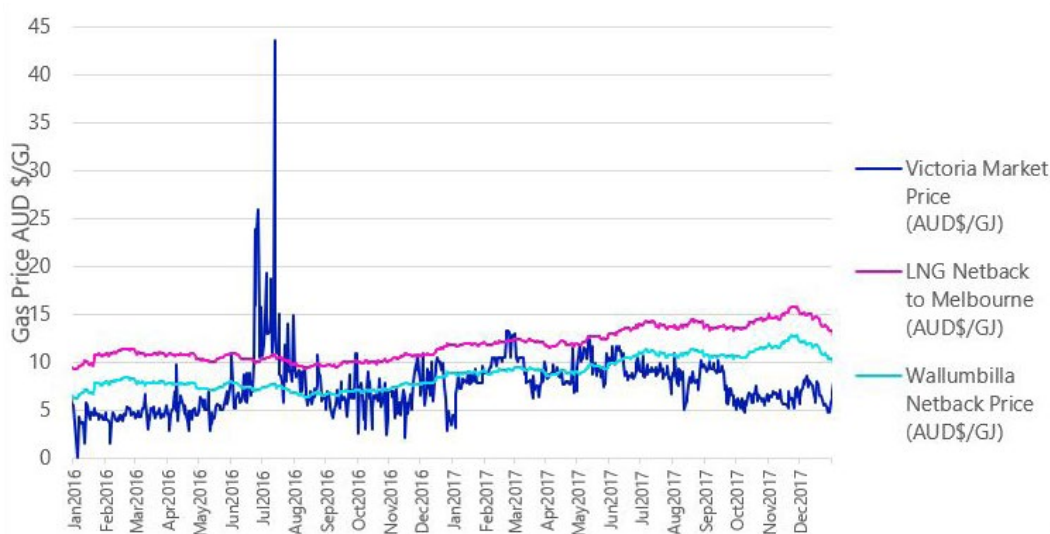


Figure 2-10: Victorian spot price vs LNG netback price

Source: AEMO and AGL analysis

12 <www.accc.gov.au/publications/serial-publications/gas-inquiry-2017-2020/gas-inquiry-april-2019-interim-report>

13 <<https://www.accc.gov.au/system/files/Gas%20inquiry%20-%20January%202020%20interim%20report.pdf>>

14 <www.accc.gov.au/media-release/investment-required-for-lower-priced-gas>

This can be seen in **Figure 2-10**, which shows the actual Victorian spot price shifting up to a north Asia LNG netback price plus pipeline transportation costs to deliver gas to Melbourne (assuming 12 per cent Brent for LNG pricing). Worth noting is that during the most supply constrained period during winter 2016, peak spot prices reached in excess of \$40/GJ. **Section 2.2.8** of this chapter explains the netback pricing methodology.

The ACCC January 2020 update to the Gas Inquiry 2017-20 Interim Report noted:

Due to the cost of transportation between the Southern States and Queensland, there is a range of possible pricing outcomes in gas supply negotiations in the Southern States, which would usually be expected to fall between:

- *the buyer alternative (representing a ceiling in negotiations)—the LNG netback price at Wallumbilla plus the cost of transporting gas from Wallumbilla to the user's location, and*
- *the seller alternative (representing a floor in negotiations)—the LNG netback price at Wallumbilla less the cost of transporting gas to Wallumbilla or the forward cost of production (whichever is higher).*

Further, a southern supplier would be expected to seek a higher price the further away a gas user is from Queensland. Since gas users in Victoria are located further away from Queensland than users in NSW and South Australia, they will likely be offered higher prices than users in those other states.

Conversely, if there were sufficient supply and diversity of suppliers in the Southern States, this would be likely to alter the relative bargaining positions of gas suppliers and gas buyers. Gas buyers would be able to source gas from another supplier in the Southern States rather than having to transport it from Queensland, and increased competition would be likely to lead suppliers to offer prices closer to the 'seller alternative' price.

In this scenario, the prices offered by suppliers in the Southern States would be lower the further away the source of supply is from Queensland.

The impact to Victorian spot gas prices when there is supply constraints can also be seen in market.

This highlights the importance to Victoria of alternative supply sources, either through new sources of production or imports, to replace declining local production and create price competition.

2.2.6 Infrastructure constraints

Australia's south-eastern states have typically seen a transmission pipeline linking a gas basin and the closest demand centre. Over the past 20 years, these pipelines have become interconnected and many have become bi-directional. Most recently, with the addition of the Northern Gas Pipeline, it is theoretically possible for the east coast to access gas from offshore basins in northern Australia, although the capacity of that pipeline is limited to 90 TJ/day.

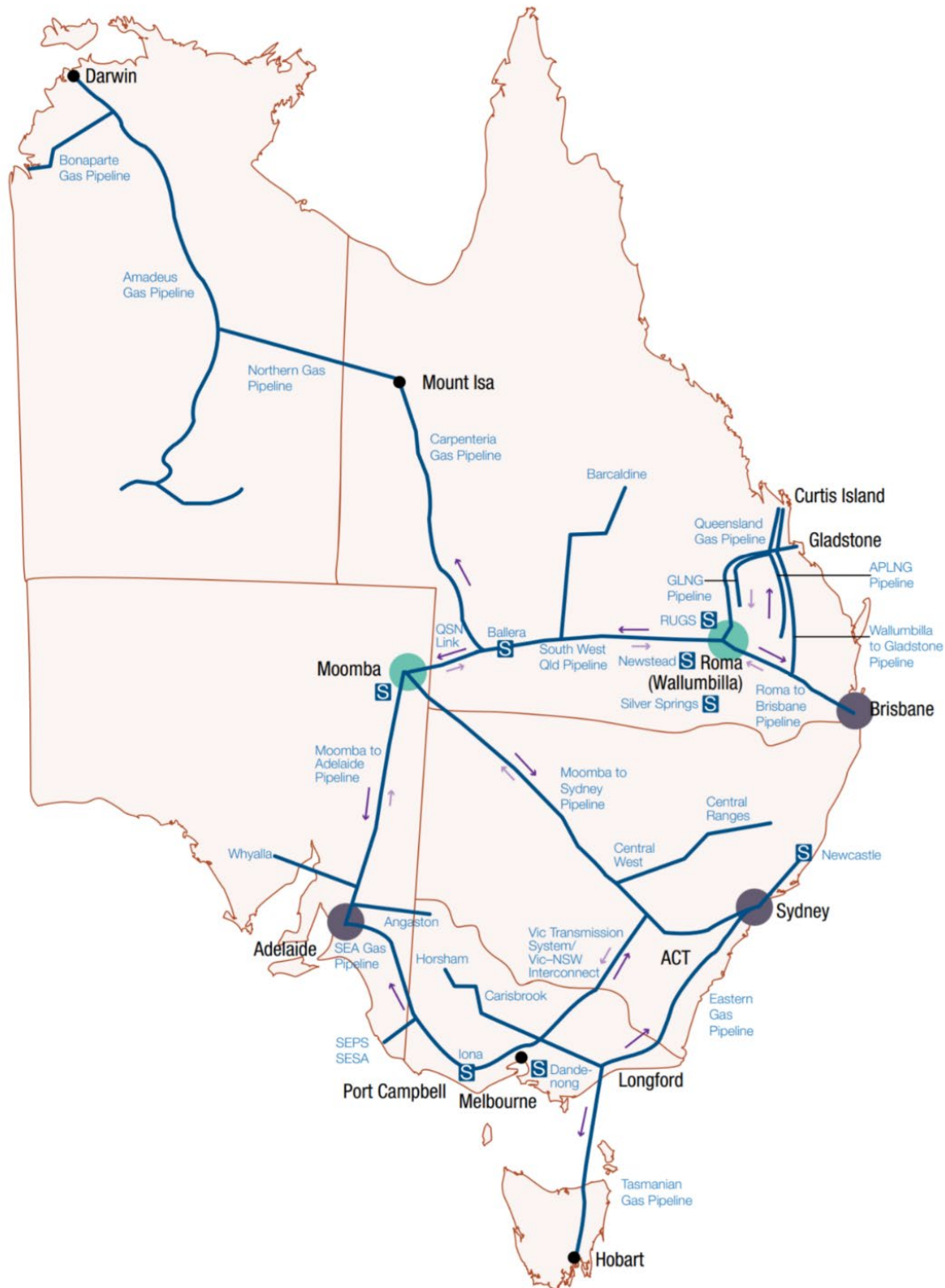
Figure 2-11 shows the main pipelines on the east coast of Australia and indicates which are bi directional and which are single directional. Connections from Queensland to the south-eastern states are via the South West Queensland Pipeline, the Moomba to Sydney Pipeline and the Victoria- to-New South Wales interconnect. While the Eastern Gas Pipeline connects Victoria to Sydney, this pipeline is currently not bi-directional and only flows gas from south to the north. Similarly, the South Eastern (SEA) Gas pipeline connecting Victoria and South Australian is also not bi-directional.

The ability to draw on gas from Queensland for delivery to southern markets is limited due to restrictions in pipeline capacity meaning that current infrastructure is insufficient to provide a capacity solution. The South West Queensland Pipeline has maximum capacity of 384 TJ/day, flowing from Queensland to south states.

As **Figure 2-12** illustrates, the South West Queensland Pipeline has historically been close to being fully utilised during Australia's winter months and will be unable to support sufficient gas flows south from Queensland to fill the shortfall forecast from 2024.

During periods of lower demand in the southern states, the South West Queensland Pipeline, the Moomba to Sydney Pipeline and Moomba to Adelaide Pipeline are still heavily utilised to transport gas south to refill storage facilities. An increased reliance on Queensland will cause a bottleneck to gas flows to the south-eastern states unless additional pipeline infrastructure is added.

The AEMO Gas Statement of Opportunities (2020) has considered how the decline in gas production in the south will lead to an increased reliance on the South West Queensland Pipeline over time. **Figure 2-13** below shows that flows along the South West Queensland Pipeline are forecast to be to the south for approximately 95 per cent of days in 2022, and for all days in 2023 and 2024, ultimately reaching the maximum capacity of the pipeline. This highlights the southern states' increasing dependence on gas from northern fields if alternate southern supply options are not developed.



▲
Figure 2-11: Major pipelines on the east coast of Australia
 Source: AER

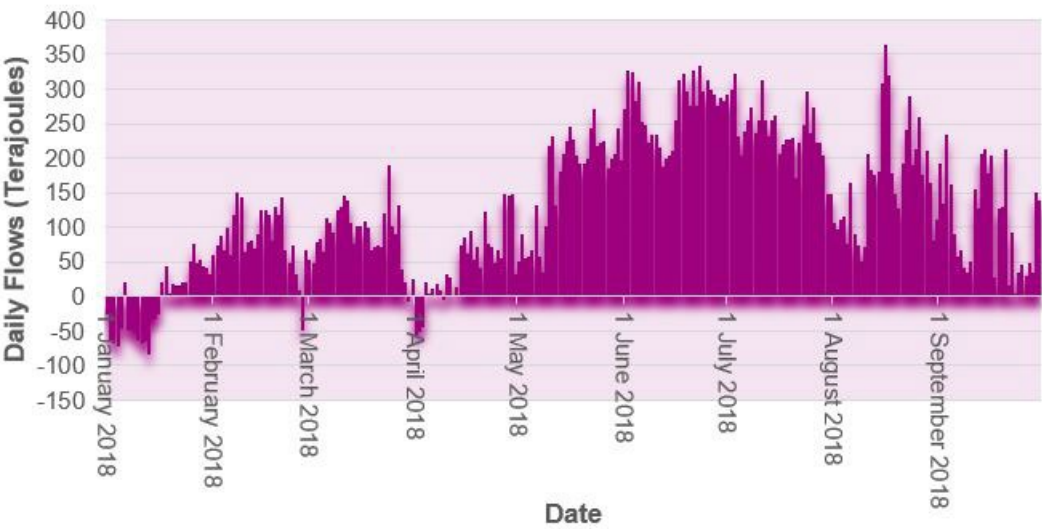


Figure 2-12: Flows on the South West Queensland Pipeline. Positive number is flow from Queensland to southern states. Negative number is flow from southern states to Queensland
Source: AEMO Gas Bulletin Board

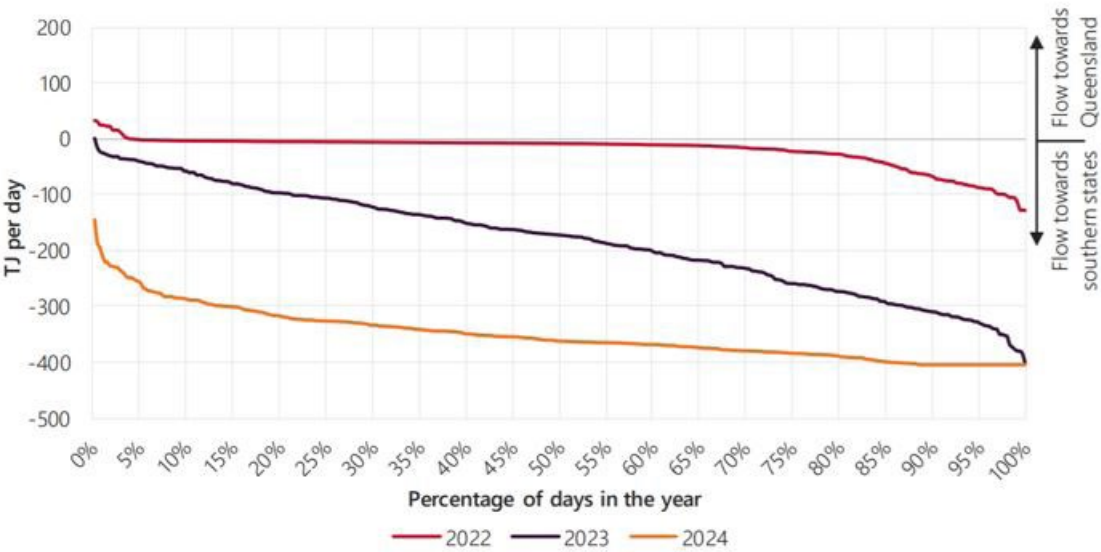


Figure 2-13: Forecast cumulative distribution of flows along the SWQP for years 2022 to 2024; (AEMO) Central scenario, existing and committed projects.

Investing to loop or expand this South West Queensland Pipeline would shift the bottleneck to the next pipelines downstream, such as the Moomba to Sydney pipeline and the Moomba to Adelaide pipeline. Upgrades to these pipelines would shift the bottleneck to the Eastern Gas Pipeline, SEA Gas pipeline and the Vic-NSW Interconnector.

If a new pipeline was constructed from Wallumbilla in Queensland to Melbourne in Victoria it would be more than 1,500 kilometres long, cost in excess of \$2 billion to design and construct and the development approvals and construction would take approximately five to six years.

The unwillingness of gas producers or the lack of reserves to underpin offering long-term gas supply agreements for the domestic market compromises the economics underpinning any investment in pipeline expansions. Investment in transmission pipelines in Australia is expensive and requires long term investment and contractual commitments. This type of investment will also usually require long term transportation agreements of 20 years to underwrite the scale of investment. As an example, the 12-inch, 622-kilometre Northern Gas Pipeline linking Tennant Creek in the Northern Territory to Mount Isa in Queensland had a budget of \$800 million and took five years to develop, adding just an additional 90 TJ/day (approximately 33 PJ per annum) of potential supply.

In comparison, the Project would only require an approximately 57-kilometre pipeline with additional capacity of up to 160PJ per annum (if required) to meet the gas supply needs of south eastern Australia.

In its 2019 Gas Statement of Opportunities, the AEMO considered whether a further interconnection between Queensland and New South Wales would alleviate shortfalls in south-eastern Australia. The AEMO considered two sensitivities:

- A new gas transmission connection from Queensland (Wallumbilla hub) to New South Wales, without considering any new supply to the system – this pipeline has been assumed to have a capacity of 400 TJ/day and be bi-directional between Queensland and New South Wales.
- Additional supply of up to 100 TJ/day through the development of gas fields in the Narrabri area in addition to a new pipeline.

Under both these scenarios the AEMO concluded the scale of shortfalls could be reduced but they would not delay the projected shortfalls.

Bloomberg New Energy Finance report (19 December 2018) suggested that LNG import terminals provide a viable alternative source of supply:

LNG imports could help the southern region by providing another option for new gas supply and reducing the supply uncertainty for gas consumers.

LNG imports via floating storage and regasification units (FSRU) can be fast and provide some certainty on additional gas supply in a few years.

2.2.7 LNG imports as an alternative

LNG import terminals have been operating around the world for decades and are proving to be flexible, reliable and economical access points to global gas supplies. They have demonstrated that alternative supply can increase pricing competition and support decarbonisation plans in the electricity sector as economies move from a dependency on coal to more renewable energy sources.

Floating storage and regasification unit (FSRU) technology for LNG importation is now widely used and offers advantages over traditional import terminals. FSRUs are easily decommissioned and relocated once they are no longer required. They can also be moved for maintenance or in emergencies, can be developed with shorter lead times and can be leased, providing economic benefits to customers and generating lower impacts to communities compared with capital intensive and long-term onshore facilities.

A map of existing FSRUs and floating storage units (FSUs) in 2018 is shown in **Figure 2-14**. In addition to these, over 50 FSRU projects are in various stages of development and operations.

The AEMO March 2019 Gas Statement of Opportunities report (p. 55) stated that:

An import terminal in Victoria, either Melbourne or Gippsland, has the biggest projected impact to reduce projected shortfalls.

In addition to providing an additional unconstrained source of gas for Victoria, this terminal is projected to reduce pipeline and storage infrastructure congestion, enabling greater access to supply from northern fields.

This development is projected to reduce total system shortfalls by up to 265 PJ a year by 2030 and delay the timing of the first shortfalls by five years (to 2029).

The AEMO March 2020 Gas Statement of Opportunities report (p. 52) commented on a Victorian import terminal scenario stating that:

With this supply, if only existing and committed projects are otherwise available, then this import terminal in Victoria can support declining southern resources and is forecast to push back any forecast supply gaps by up to six years to 2030 in the Central scenario.

2.2.8 Economics of gas transport

The AEMO March 2019 Gas Statement of Opportunities report considered import terminals in different states. It identifies that states other than Victoria were constrained by congestion and a requirement to develop bi-directional pipeline capabilities and projected that only a project located near Melbourne could achieve full capacity.

Figure 2-15 and Figure 2-16 illustrate the economics of LNG imports compared with diverting gas from Queensland. The figures are taken from worked examples appearing on the ACCC website¹⁵ and haulage charges from the AEMO. Whilst LNG prices and foreign exchange rates will continue to fluctuate and at the time of reading will differ to the worked example, the critical factor is the economics of transporting gas by pipeline compared with LNG transport by ship and therefore the logic remains valid.

For illustration purposes the ACCC used an US\$8/ million British thermal units¹⁶ (MMBtu) LNG marker price in north Asia and freight of US\$0.50 (MMBtu is a measure of the energy content in fuel). Using a 0.75 exchange rate and 1.055 conversion rate for MMBtu to GJ, this translates to a A\$9.48/GJ Free on Board (FOB)¹⁷ Gladstone LNG price, as shown in Figure 2-16.

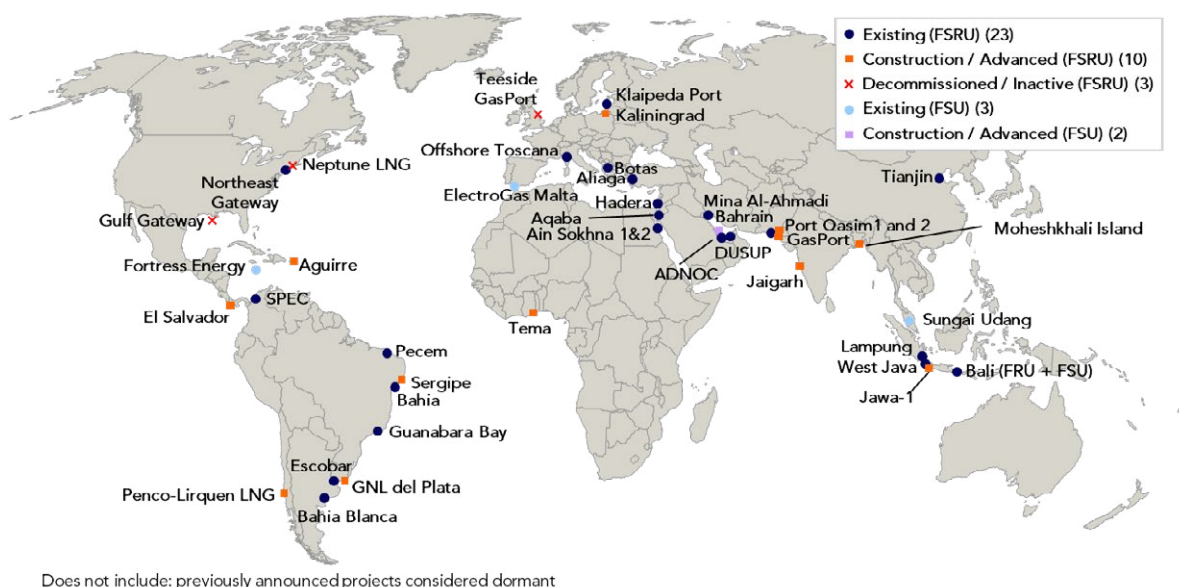


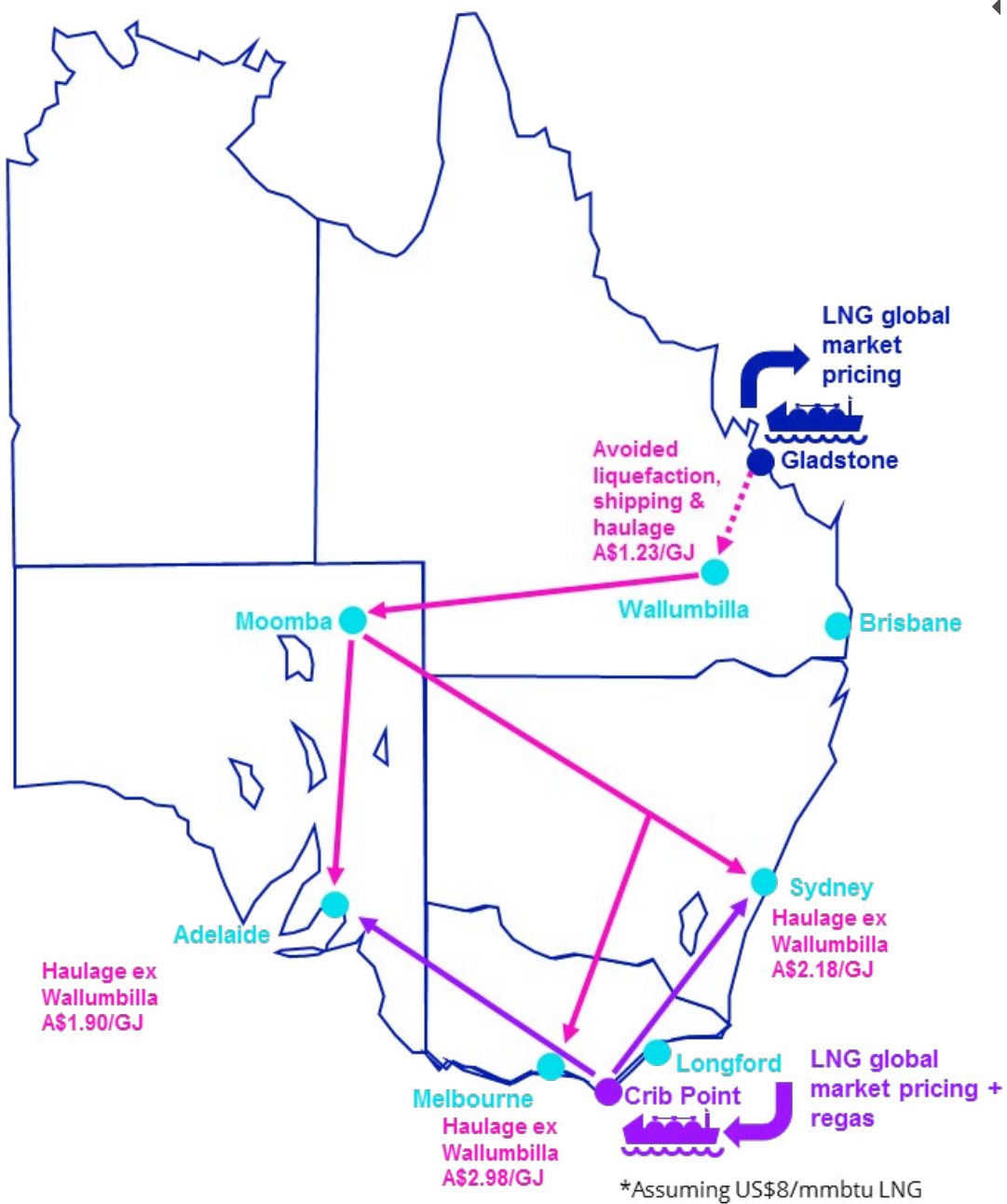
Figure 2-14: Existing FSRUs, 2018

Source: Poten & Partner

¹⁵ <www.accc.gov.au/system/files/Guide%20to%20the%20LNG%20netback%20price%20series%20-%20October%202018.pdf>

¹⁶ Btu (British thermal unit) is a traditional Imperial unit of energy. Spot LNG pricing moves with supply and demand. Recent years have seen LNG trade significantly above this price as well as below.

¹⁷ FOB (Free on Board) means the cost of the cargo, with freight costs excluded.



◀ **Figure 2-15:**
Pipeline haulage
charge from
Queensland
Wallumbilla

If excess gas was sold by LNG producers into the domestic market rather than exported as LNG, the producers would save the costs associated with gas consumed as fuel during the liquefaction process, as well as LNG plant operating expenditure. Subtracting LNG plant fuel, efficiency and operating expense from the A\$9.48/GJ FOB Gladstone price and the marginal costs of transportation to Wallumbilla, the ACCC data estimates an LNG netback¹⁸ price at Wallumbilla of A\$8.91/GJ based on US\$8/MMBtu LNG marker price in north Asia, as shown in **Figure 2-17**.

The economics illustrated above are an oversimplification as the pipeline capacity charge calculation assumes the capacity is fully utilised, which may be the case in winter, but is unlikely in summer. This means the cost of piping gas to Victoria at times of lower capacity can be more expensive than outlined above.

Therefore, in the south-eastern states where a supply shortfall is soon expected, having an alternative gas supply point such as the Project would help alleviate the shortage and likely reduce prices for consumers in the south-eastern states. An LNG import facility also provides access to the global market and does not rely on the development of contingent or yet to be discovered resources. Importantly, an LNG import facility would remove supply uncertainty and ensure security of gas supply to meet the needs of AGL's 1.4 million gas customers.

2.2.9 Security and stability of supply

The AEMO March 2019 Gas Statement of Opportunities report noted that an import terminal in Victoria has the biggest projected impact to reduce projected shortfalls in the south-eastern states.

The Project outlined in this EES would provide Victoria an opportunity to develop a natural gas supply source from existing and new LNG projects in Australia and around the world.

The Project has the potential to supply up to 160 PJ of natural gas per annum. The Gas Import Jetty life is initially projected to be 20 years although it may be extended if security and stability of gas supply to south-eastern Australia remain. The Project could also be shortened if a significant shift in demand occurred or sufficient gas discoveries were found in the southern reserves. The pipeline has a design life of 60 years and being bi-directional, could continue to operate when the FSRU was no longer in use if gas to the region was required.

The Project would play an important role in three ways:

1. Liquidity – additional supply from a new source putting downward pressure on prices for households, business and industry with increased competition.
2. Security and reliability – LNG imports provide a new source of supply capable of reacting to peak demand periods and providing additional emergency back-up supply for the south eastern states if a major outage or plant failure occurred, such as the 1998 Longford incident.
3. Capacity and flexibility – LNG imports allow consumers to have a secure, stable source of energy supply as the energy supply mix transitions to more renewables. The Project also enables short and longer-term supply as well as the ability to bring spot cargos in at short notice as required.

Although the proposed Gas Import Jetty is primarily designed to fulfil the predicted gas shortage from 2024 or earlier, AGL also recognises the need to improve energy efficiency and reduce gas demand. To support this objective AGL conducts an ongoing campaign with its customers about ways they can reduce energy demand in their home.

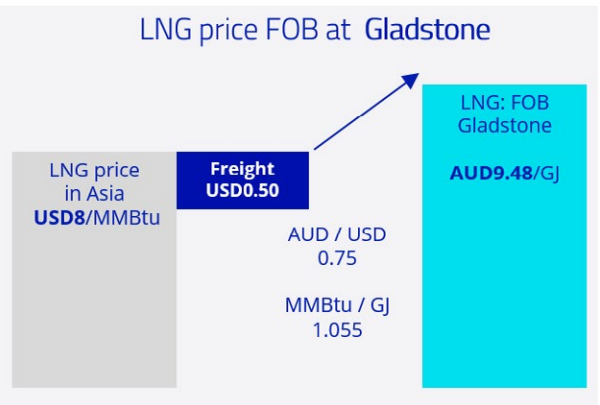
The campaign, designed to both improve household efficiency and reduce gas demand, educates customers about using more efficient reverse-cycle heating within their existing air conditioners which is significantly cheaper to run to warm your home than gas central heating traditionally installed the south eastern states where gas was once plentiful and cheap. Around 40 per cent of the overall energy usage of a house goes toward heating or cooling. Customers are encouraged to monitor the impact of these changes using AGL's Energy App which shows daily usage patterns on their mobile phone.

Customers planning to or needing to replace hot water heaters, which are typically run on gas in the south eastern states, are advised to consider heat pumps which use the same technology as reverse cycle air conditioners to take ambient heat out of the air to make hot water. They are also encouraged to install solar rooftop panels, which is now happening in record numbers with around one in five houses now capturing energy from the sun. Installations in Victoria alone surged 90 per cent in the past year, thanks to a new state-based incentive scheme. Combining the two, makes the cheapest hot water in the world.

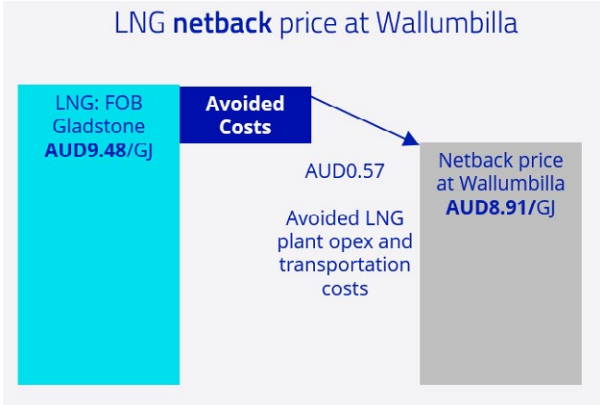
¹⁸ A 'netback' pricing assessment is the effective price to the producer or seller at a specific location or defined point. For example, liquefied natural gas (LNG) netback prices may be determined by the market natural gas price at market destinations less the cost of pipeline transportation, regasification, waterborne shipping and liquefaction (source: risk.net).

2.3 Gas is an important enabler of the energy transition

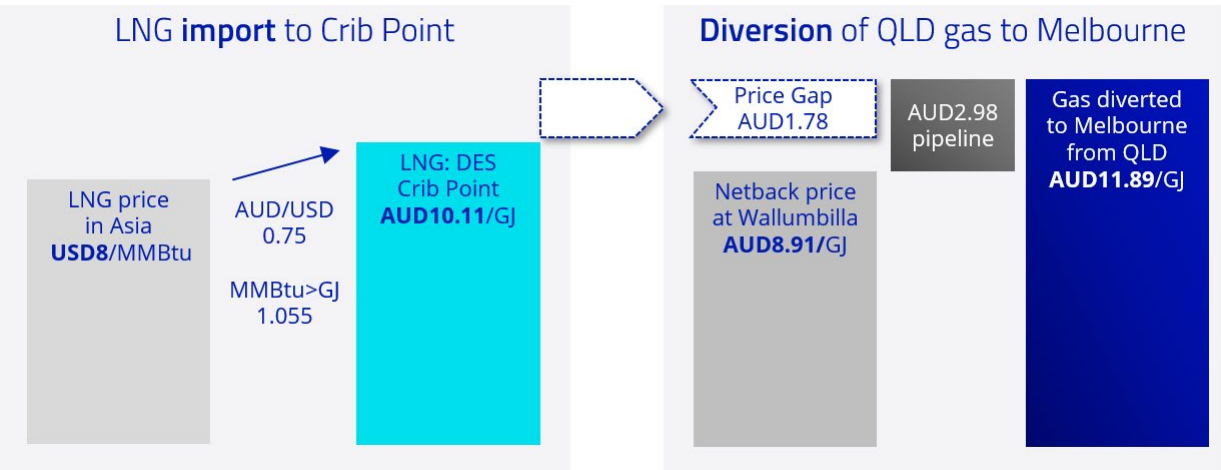
Australia is among the 195 signatories to the 2015 United Nations Paris Agreement. The central aim of the agreement is to strengthen the global response to the threat of climate change by keeping a global temperature rise this century well below two degrees Celsius (° C) above pre-industrial levels and to pursue efforts to limit the temperature increase even further to 1.5° C.



▲ **Figure 2-16:** LNG FOB Gladstone calculation
Source: ACCC LNG netback price series



▲ **Figure 2-17:** Calculation of LNG netback price at Wallumbilla
Source: ACCC LNG netback price series



▲ **Figure 2-18:** Imported LNG prices vs piped LNG price
Source: AEMO haulage charges and ACCC LNG netback price series

The Victorian Government has committed to reducing greenhouse gas emissions and to transition to more renewables in its legislative and planning framework through:

- *Climate Change Act 2017* – which includes a long-term emissions reduction target of zero emissions by 2050 and requires the preparation of climate change strategies, adaption action plans and emission reduction pledges.
- *Plan Melbourne* – the long-term planning policy for metropolitan Melbourne to develop an environmentally sustainable city with a rapid forecast population growth to 2050.
- *Victoria's Renewable Energy Action Plan* – which sets the pathway to encourage investment in the Victorian energy sector so that Victorians continue to benefit from a renewable, affordable and reliable energy system into the future.
- the *Victorian Renewable Energy Target (VRET)* – which sets a target of 50 per cent of Victoria's energy needs supplied from renewable sources by 2030.
- consideration of interim emission reduction targets.

The energy sector, and particularly electricity generation, has an important role in this transition. Electricity generation produces around one-third of Australia's greenhouse gas emissions. Approximately three-quarters of the existing steam-based generation fleet is beyond its original design life.

Due to its current fleet of generators and position as one of Australia's largest electricity generators, AGL is currently Australia's largest corporate emitter of greenhouse gas emissions. AGL's operational footprint is around 44 million tonnes of greenhouse gas per annum, with the vast majority of emissions produced by just four power stations: Bayswater; Liddell; Loy Yang A; and Torrens Island. These four generation assets supply electricity to millions of Australian homes and businesses.

AGL has announced plans to progressively close its coal-fired generation fleet, starting with the first unit at Liddell in 2022 and closing the final unit at Loy Yang no later than 2048. The closure of coal fired generation is part of a broader shift to renewable energy sources. AGL is already Australia's largest privately-owned investor in renewable technologies, with a portfolio of large-scale renewable energy assets including: the Hallett wind farms in South Australia; the Macarthur and Oaklands Hill wind farms in Victoria; hydro power stations in Victoria; and the Nyngan and Broken Hill solar plants in New South Wales.

AGL's renewables generation fleet plays a critical role in the transition to a decarbonised generation sector to provide valuable low cost and efficient generation over the coming decades while the electricity sector transitions to more renewables and distributed energy resources.

Figure 2-19 shows the type, location and investment of AGL new energy projects. The company is investing \$1.9 billion in these projects with an additional A\$1.5 billion invested in projects subject to feasibility studies.

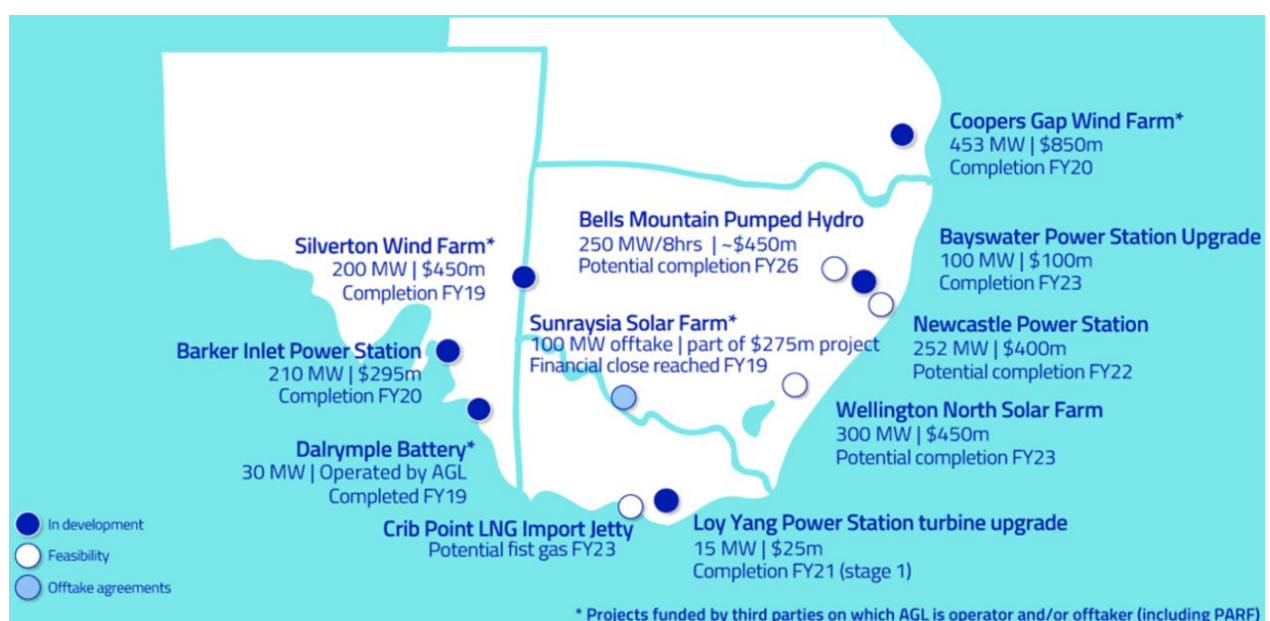


Figure 2-19: AGL's new energy projects
Source: AGL

Renewables supported by a range of technologies will significantly reduce overall greenhouse emissions from the national energy market (NEM). The combined emissions intensity of the NEM in 2017/18 was 0.82 tonnes of carbon dioxide equivalent per megawatt-hour (tCO₂e/MWh). Black coal generators are typically higher than this level (around 0.9 tCO₂e/MWh), with brown coal generation much higher (around 1.2 tCO₂e/MWh). Renewable energy has an emissions intensity near zero. The overall high intensity of the NEM reflects the high capacity factor of 'baseload' coal-fired power stations.

As coal-fired power stations approach the end of their intended operating life they will need to be replaced with low-cost renewable technology that is firmed by a range of more flexible technologies such as gas-powered generation, hydro, battery storage and demand response.

As the market operator the AEMO has made clear in its Electricity Statement of Opportunities report and Integrated System Plan (ISP) modelling, key to this transition is flexibility in resources and greater interconnection to access lowest-cost generation across the NEM.

Each technological option available contributes to keeping costs down and facilitates decarbonisation by enriching the diversity of technological alternatives and energy sources. The AEMO's modelling suggests that gas-powered generation will continue to play an important role in providing generation diversity to achieve decarbonisation objectives, particularly over the near term if NEM interconnection remains constrained and the uptake of new firming technologies is slower than anticipated.

Cycle gas turbines and open cycle gas turbines generation technologies both have a lower emissions intensity combined than the NEM average, ranging on average around 0.4 to 0.7 tCO₂e/MWh, depending on the individual facility. However, because of the way these facilities are used as peaking stations in periods of high demand, they do not contribute as much to overall emissions as coal-fired power stations because they have a lower capacity factor (they are dispatched less regularly during high demand periods).

On an overall basis, renewable generation that is firmed by gas has a very low emissions intensity (less than 0.2 tCO₂e/MWh) because only a small percentage of overall electricity dispatched is provided by the gas peaking plant, with the remainder provided by renewable sources. Nevertheless, it is critical that gas is available for these facilities so they can generate at short notice in shortfall periods, including when gas demand may otherwise be high due to consumer and industrial demand.

The Project proposed in this EES, in addition to supplying gas to our gas customers, is needed to provide a reliable and secure supply of gas for quick-start gas-powered electricity generation which, in turn, is needed to enable a cost-effective energy transition to occur for AGL as well as the broader Australian electricity sector.

The AGL Greenhouse Gas Policy states that it will:

- continue to provide the market with safe, reliable, affordable and sustainable energy options
- not build, finance or acquire new conventional coal-fired power stations in Australia (without carbon capture and storage)
- not extend the operating life of any of its existing coal-fired power stations
- close all existing coal-fired power stations in its portfolio by 2048
- improve the greenhouse gas efficiency of its operations and those it has influence over
- continue to invest in new renewable and near-zero emission technologies
- make available innovative and cost-effective solutions for its customers, such as distributed renewable generation, battery storage, and demand management solutions
- incorporate a forecast of future carbon pricing into all generation capital expenditure decisions
- continue to be an advocate for effective long-term government policy to reduce Australia's emissions in a manner consistent with the long-term interests of consumers and investors.

To meet these policy objectives, AGL needs a secure and stable supply of lower emission fuel (such as gas to run quick-start gas generation) to continue to meet the energy needs of customers when renewables cannot provide a reliable energy supply.

The Project would be crucial for providing a reliable supply of lower emission fuel to generate the much needed firming capacity required for an effective transition to renewables in the next decade.

2.4 Current initiatives to alleviate gas supply issues

Several relevant initiatives to alleviate gas supply issues are being considered by the Victorian and Commonwealth governments. These include the Victorian Gas Program and the Australian Domestic Gas Security Mechanism.

2.4.1 Victorian Gas Program

The Victorian Gas Program is a comprehensive program of scientific research and related activities to assess the potential for further discoveries of onshore conventional gas and offshore gas in Victoria. The Victorian Gas Program also investigates whether the state's current underground gas storage capacity could be expanded. The program will operate until mid-2020 and provide a resource estimate to inform future Victorian Government decisions. The Victorian Gas Program has three scientific components:

- onshore conventional gas
- offshore gas
- underground gas storage.

The Victorian Gas Program focuses on Victoria's two most prospective regions for undiscovered accumulations of gas: the Otway Basin (currently considered as having the highest potential) and the Gippsland Basin.

The Project is consistent with the Victorian Gas Program as it contributes to a diversification of gas supply and an increase in competition in the wholesale gas and pipeline transmission markets. The Project also avoids some of the concerns over potential impacts of on-shore gas field development on land valued for its agricultural, environmental, social or cultural heritage values.

2.4.2 Australian Domestic Gas Security Mechanism

Commonwealth Government policies such as the Australian Domestic Gas Security Mechanism (ADGSM) provide some potential for short-term relief to gas shortfalls. The ADGSM was established to enable the Commonwealth Government to place export controls on uncontracted gas destined for LNG export to shore up domestic supply.

However, the determination process can occur as late as 1 November in the year preceding a domestic shortfall year, whereas most Australian gas volumes are delivered under longer-term supply contracts.

The short notice periods under the ADGSM are likely to impact the ability of the mechanism (if triggered) to materially improve gas procurement costs due to the difficulty to renegotiate long-term agreements at short notice for the following year. The ADGSM does not solve the pipeline constraint nor transportation cost issues discussed in previous sections of this chapter.

The ADGSM has not been triggered yet because under the Australian East Coast Gas Domestic Gas Supply Commitment, the three east coast LNG exporters have agreed that if a shortfall occurs they will supply uncontracted gas to the domestic market on reasonable terms. This commitment is for the 2019 and 2020 calendar years.

While the ADGSM may provide additional domestic supply, it is expected this supply would be constrained by infrastructure limitations and remain at relatively high prices due to production and transportation costs as described in **Section 2.2.8** of this chapter. The federal government has advised that it will keep the ADGSM in place until its scheduled end in 2023.¹⁹

2.5 FSRU approach and site selection

This section provides an overview of the LNG import options considered during the development of the Gas Import Jetty Works, including an explanation of the FSRU approach in preference to a land-based alternative, and a rationale for selecting the proposed site at Crib Point.

2.5.1 Technology options

Both onshore and offshore regasification and storage technologies were considered during the gas import options screening phase.

An onshore (land-based) storage facility would typically consist of large storage tank infrastructure and a regasification plant. This type of onshore development takes around three and a half to four years to construct and requires a large onshore footprint. In comparison, an FSRU is an LNG vessel that includes regasification equipment which can be moored at the end of a jetty, providing additional separation from nearby communities, with a small onshore facility situated near the end of the jetty. On conclusion of the Project the FSRU can be relocated elsewhere.

Table 2-2 presents a comparison of the onshore and offshore facilities considered for the Project including the relevant advantages and disadvantages that were considered during the screening phase.

Developing an FSRU-based project as opposed to land-based facilities has the following advantages:

- removes the requirement to construct large land-based infrastructure that would need to be decommissioned and rehabilitated upon Project completion
- the receiving infrastructure on land has a comparatively much smaller footprint
- improved site safety due to flexibility to leave the berth during emergencies if required
- additional safety buffer by being further away from existing residential receptors
- can be developed in the shortest amount of time in order to achieve the Project objective of ensuring new forms of gas supply to meet the forecast gas shortage in 2024.

¹⁹ <<https://www.minister.industry.gov.au/ministers/canavan/media-releases/review-finds-gas-policy-boosts-domestic-supply-and-helps-lower>>

2.5.2 Siting

Crib Point Jetty (Victoria) was selected as the location for the gas import jetty. Victoria is the largest gas market by volume consumed in south-eastern Australia.

This section describes the screening assessment undertaken of potential sites in south-eastern Australia for the Project.

Screening assessment

Eight sites were initially evaluated by AGL as potential locations to import LNG into south-eastern Australia, including Port of Newcastle, Port Botany and Port Kembla (New South Wales), Corio Quay Precinct, Port of Melbourne and Crib Point (Victoria), Port Adelaide (South Australia) and Bell Bay (Tasmania).

Table 2-2: Comparison of onshore (land-based) and offshore (floating) facilities

	Onshore storage and regasification	FSRU
Location	<ul style="list-style-type: none"> On land Requires larger footprint for storage and regasification infrastructure Likely to be positioned closer to onshore residential dwellings Demolition and remediation required at the end of the Project 	<ul style="list-style-type: none"> Moored adjacent to a jetty Able to make use of existing jetty infrastructure Smaller footprint on land in comparison to onshore storage and regasification FSRU situated at end of jetty in port waters, further away from onshore residential dwellings
Appearance	<ul style="list-style-type: none"> Potentially a single large storage tank or multiple storage tanks and regasification processing facility Industrial facility likely to be located closer to nearby sensitive receptors (i.e. residential dwellings, public open space) Would be located closer to sensitive receptors but may be able to use topography, vegetation and/or existing infrastructure for screening 	<ul style="list-style-type: none"> Able to be moored alongside a jetty and not substantially different in appearance from other vessels that use existing port facilities Likely to be located further from nearby onshore residential dwellings but could be widely visible in an open bay
Construction	<ul style="list-style-type: none"> Construction would be predominately in-situ over three and a half to four years Would require a larger construction footprint than an FSRU due to larger scale of onshore infrastructure Potential increased environmental risks regarding contaminated soil exposure and waste disposal during construction associated with footprint of onshore facilities 	<ul style="list-style-type: none"> The FSRU is an existing vessel, and would be commissioned with safety and production systems verified for optimal operating parameters prior to being brought to the jetty Smaller construction footprint on land compared to onshore storage and/or regasification, requiring only the installation of a gas receiving facility and nitrogen injection facility Double-hulled vessel with a number of passive and active safety systems
Construction timeframe	<ul style="list-style-type: none"> Around 42 to 48 months 	<ul style="list-style-type: none"> Shorter lead time, approximately 12 to 18 months for chartering arrangements of existing FSRU from an FSRU owner and operator
Construction cost	<ul style="list-style-type: none"> An onshore terminal can typically cost 100% more than the cost of a new FSRU (Songhurst, 2017) 	<ul style="list-style-type: none"> FSRU procured under a lease arrangement. No construction costs required as it would be under a lease arrangement
Emergency events	<ul style="list-style-type: none"> Ignition exclusion zones would be closer to residential dwellings therefore increasing safety concerns 	<ul style="list-style-type: none"> If any safety or operational issues arise, the FSRU can depart the berth if required and return to a ship yard for maintenance and an alternate vessel can be sourced Located further away from land-based residential areas Exclusion zone would be over water and away from houses, other structures and vegetation
Decommissioning	<ul style="list-style-type: none"> Infrastructure redundant after project closure, potential requirement for removal and remediation 	<ul style="list-style-type: none"> The FSRU would be moored at a jetty and at the end of the Project it would depart the jetty for use elsewhere as an FSRU or LNG carrier Jetty Infrastructure and receiving infrastructure on land will need to be decommissioned

Initial screening criteria for the eight potential sites included:

- proximity to hazards, possible ignition sources and other safety considerations
- proximity to occupied buildings and consideration of nearby activities
- exclusive access to a berth capable of accommodating vessels with overall length up to 300 metres
- a deep-water swing basin/ship turning basin of 600 metres in diameter
- a deep-water approach channel of suitable width to accommodate double berthed vessels
- a berth of at least 13 metres deep at lowest astronomical tide
- separation from the shipping channel such that surge from passing ships does not impact the safe operations of side by side berthing of an FSRU and LNG carrier during unloading
- existing mooring dolphins (marine structures), or ability to upgrade a berth, to accommodate the parallel length and deadweight tonnage (how much weight a ship can carry) of the FSRU.

The initial screening assessment resulted in the identification of three shortlisted options being Port Adelaide (South Australia), Port Kembla (New South Wales), and Crib Point (Victoria) that were subsequently considered in further detail.

The other five sites were ruled out due to a number of factors, including the lack of suitable berths, shipping channel access, operating congestion within shipping channels, and limited existing gas transmission pipeline network with sufficient capacity to deliver gas to the market effectively and in a timely manner.

Shortlisted options assessment

The three shortlisted options identified as the most feasible to meet the screening assessment criteria comprised of:

- Port Adelaide in South Australia
- Port Kembla in New South Wales
- Crib Point in Victoria.

The locations of these shortlisted options in the context of south-east Australia is shown in **Figure 2-20**.

The shortlisted options assessment considered the following factors:

- access to key gas markets
 - existing gas transmission pipeline network to enable access to key gas markets
 - existing directional flow of the gas transmission network
- marine and port suitability
 - potential berthing and loading configurations
 - review of existing port uses
 - dredging requirements within already congested ports
- land availability
 - the availability of suitable land for onshore facilities
 - land access requirements
- environmental effects
 - potential environmental, health and safety effects
 - potential social and economic effects
 - dredging impacts and possible existing contamination
 - regulatory approval requirements
- economics
 - ability and cost to deliver gas to market
 - the cost of reconfiguring existing gas transmissions networks
 - cost of new pipeline and associated connections
 - construction timelines
- synergies with other gas assets
 - synergies with other existing gas infrastructure, such as gas storage facilities, gas fired power stations and customer base to optimise market efficiencies.

A summary of the evaluation of the three shortlisted options is provided in **Table 2-3**. A more detailed discussion of the suitability of each of these shortlisted options is provided in the sections following the table.

Port Adelaide site assessment

Port Adelaide is a major shipping port located 14 kilometres north-west of Adelaide in South Australia, with facilities in an Inner Harbour and Outer Harbor. It was constructed in the early 19th century and provides berths for petroleum products and the shipping of dry bulk, bulk liquid goods and commodities.

Port Adelaide was shortlisted as it provides:

- the possibility to construct through dredging a new berth west of Pelican Point power station at Outer Harbor
- available land in the port precinct for facilities at the port and an associated pipeline
- access to existing gas pipelines at Torrens Island via a new six-kilometre pipeline.

At the time of the assessment it was identified that to accommodate the proposed Project, the Port Adelaide site would require extensive dredging. This would have had the potential to impact on nearby dolphin breeding grounds.

Table 2-3: LNG import siting evaluation

Option/criteria	Port Adelaide	Port Kembla	Crib Point
Access to key gas markets	<ul style="list-style-type: none"> • Moderately suitable • Access to smaller gas market • Network modification required to access Victorian market. 	<ul style="list-style-type: none"> • Moderately suitable • Tie into the north bound Eastern Gas Pipeline restricting access to the Victorian market. 	<ul style="list-style-type: none"> • Highly suitable • Direct access to Victoria, Australia's largest domestic gas market.
Marine and port suitability	<ul style="list-style-type: none"> • Existing industrial port • Potential to create new berth through dredging. 	<ul style="list-style-type: none"> • Existing industrial port • Berth available • Proximity to rock armour potentially problematic for incoming/outbound ships. 	<ul style="list-style-type: none"> • Existing industrial port • Berth available • Proximity to rock armour potentially problematic for incoming/outbound ships.
Land availability	<ul style="list-style-type: none"> • Land available in near newly dredged berth pocket. 	<ul style="list-style-type: none"> • Limited land available near berth. 	<ul style="list-style-type: none"> • Land available for facilities at port.
Environmental effects	<ul style="list-style-type: none"> • Located in proximity to dolphin breeding area • Extensive dredging required • Potential for contaminated dredge spoil. 	<ul style="list-style-type: none"> • Extensive dredging required • Potential for contaminated dredge spoils. 	<ul style="list-style-type: none"> • Located within the Western Port Ramsar site • No capital dredging required.
Dredging requirements	<ul style="list-style-type: none"> • In excess of 2,000,000 m3 of dredge spoils expected. 	<ul style="list-style-type: none"> • Deepening required • Estimated at 600,000 m3 of dredge spoils. 	<ul style="list-style-type: none"> • No capital dredging required • Minor seabed levelling works required (sweeping).
Economics	<ul style="list-style-type: none"> • Costs required for dredging and development of berth • Relatively short pipeline with potential for reduced cost and less impact on landholders • High costs for gas network modifications. 	<ul style="list-style-type: none"> • Existing jetty provides cost benefit but required modifications • Eastern Gas Pipeline provides limited Victorian market access • High costs for gas network modifications • Longer pipeline required to access Moomba to Sydney Pipeline. 	<ul style="list-style-type: none"> • Existing jetty provides cost benefit • Longest pipeline impacting on financial feasibility and landholder disturbance • Access to largest gas market.
Synergies with other gas assets	<ul style="list-style-type: none"> • Proximity to Torrens Island Power Station • Reversal of SEA Gas pipeline required to access the largest gas market in Victoria. 	<ul style="list-style-type: none"> • No current synergies with other gas assets • Challenges to deliver gas to key markets as existing gas flow is from Victoria to Sydney • Reversal of Eastern Gas Pipeline required to deliver gas to the largest gas market (Victoria). 	<ul style="list-style-type: none"> • Synergies with Iona underground storage facility and other gas assets • Directional flow of pipeline is compatible.

The Port Adelaide site would provide access to existing gas pipelines. However, access to the wider gas pipeline network to fully serve south-eastern gas markets would require extensive pipeline network modifications, including the reversal of the Moomba to Adelaide Pipeline and the SEA Gas Pipeline, and an interconnection between these pipelines. The cost of these modifications would make the use of the Port Adelaide site commercially unviable. In addition, pipeline capacity constraints to accessing the broader gas transmission network would limit the ability of the Project to supply gas to the south-eastern gas market.

Port Kembla site assessment

Port Kembla is in the Illawarra region of New South Wales and is a key port for the import and export of dry bulk, bulk liquid, general cargo, motor vehicles and coal. It was established in 1883 and operates across two precincts, the Inner Harbour, which involves car import, general cargo and container facility, grain terminal and coal terminal, and the Outer Harbour. The port has a deep-water shipping channel that can accommodate vessels with ship lengths of 300 metres.

Port Kembla was shortlisted as it provides:

- an available berth proposed by NSW Ports in the Outer Harbour adjacent to the breakwater (an artificial offshore rock armour structure protecting the port from waves) with berthing dolphins, primarily used for fuels discharge and loading, and capacity for further facility upgrades to accommodate a vessel of 300 metres in length
- potential available land at the existing coal terminal at the foot of the breakwater, however not adjacent to the proposed berth
- a potential connection point to the Eastern Gas Pipeline.

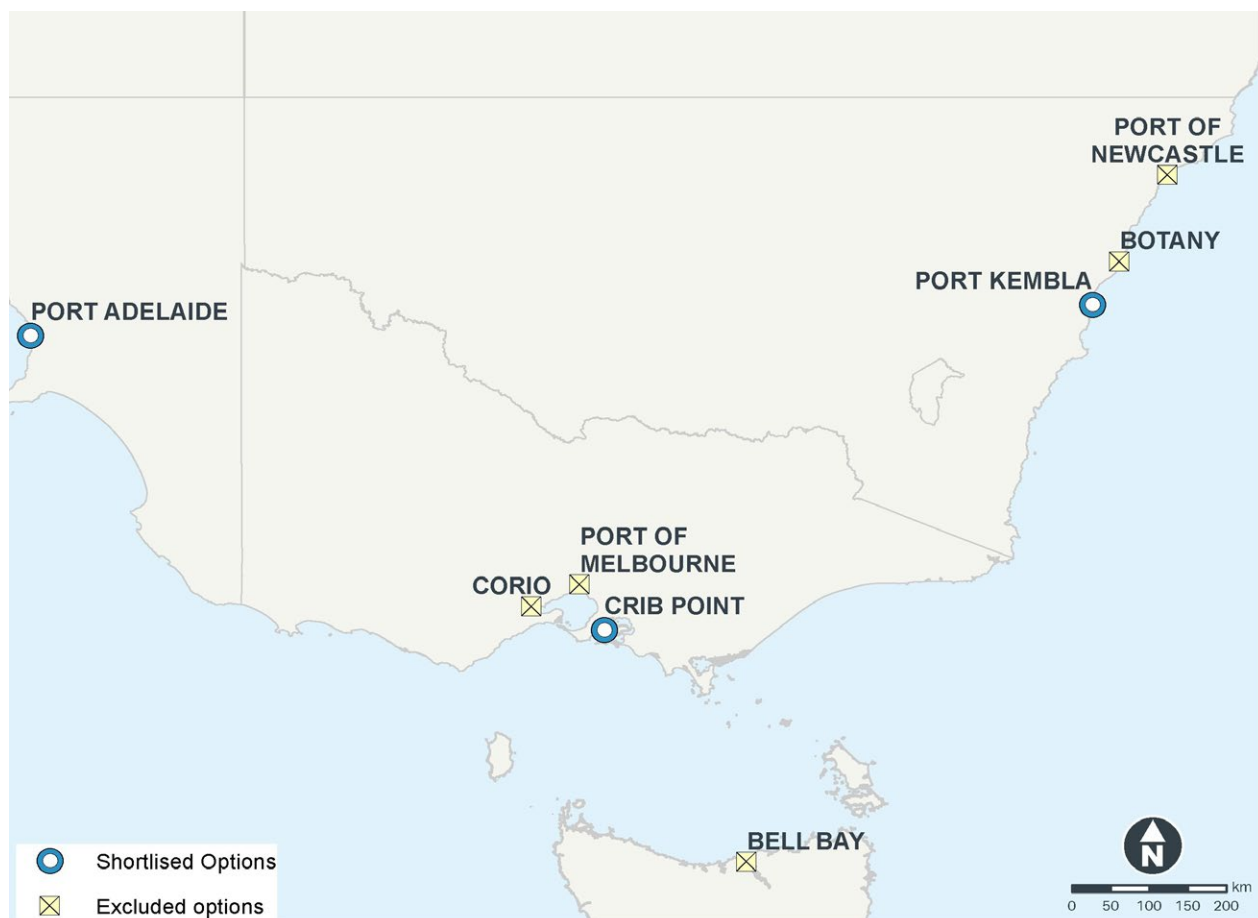


Figure 2-20: Potential sites for LNG import considered during Project development

The Eastern Gas Pipeline supplies gas between the southern gas fields in the Gippsland Basin offshore in Victoria and major gas markets in New South Wales and the Australian Capital Territory. Due to the Eastern Gas Pipeline not being a bidirectional pipeline (gas only flows in one direction, from Victoria to New South Wales) and not having sufficient capacity to supply the south-eastern gas market, it was therefore considered that an additional connection to the Moomba to Sydney Pipeline, which is bi-directional, would be necessary. Significant pipeline modifications would also be required to transport the gas to other demand centres in Victoria. This would increase the gas base price due to the additional gas transmission tariff.

Overall it was considered that the Port Kembla site would present constraints to accessing the broader gas transmission network. This would limit the capacity of the Project to supply more gas to the south-eastern gas market to fulfil the supply shortfall from 2024.

The Port Kembla site assessment also identified a number of physical constraints.

Reclamation of a large part of the Outer Harbour was under consideration to accommodate dry and containerised shipping. However, any such development would increase ship traffic in the Outer Harbour and therefore increase the risk of collision with an FSRU moored nearby, would place the LNG carriers and FSRU in the trajectory of ships leaving other terminals and reduce the manoeuvring space in the Outer Harbour, potentially leaving insufficient room to turn visiting LNG carriers. Additionally, it was considered that reclamation of the southern harbour could make the swell effect worse in the Outer Harbour and impact on the mooring of an FSRU and ship-to-ship transfers by increasing and changing the direction of swell waves, as there is less sea area in which the swell can dissipate.

Due to the limited turning space, vessels departing from the berth would require assistance from tugboats, including departure for emergencies. In addition, the wharf is armoured with rocks on its western side, increasing the risk of damage to visiting LNG carriers due to the potential effects of passing ships and ocean swell. It was identified that the FSRU would need to be berthed further west to leave sufficient safe clearance from the tip of the breakwater. This would result in a requirement for dredging of shallow water to the west of Berth 201 and subsequently would result in misalignment with existing berthing dolphins. Due to the industrial nature of the port, it was considered highly likely that any dredged spoil could be contaminated with heavy metals, requiring safe disposal in a licensed, land-based facility and potential release of contaminants in waterways.

It is noted that Australian Industrial Energy (AIE) is planning to develop a gas import terminal at Port Kembla to service the New South Wales market. AIE also considered Port Botany and Port of Newcastle in its assessment of sites. Of these locations, the Port Kembla site was considered to be preferred during the AIE assessment of alternatives noting that the AIE proposal is focused on meeting the gas needs of the New South Wales market and is proposing to dredge a new berth pocket in the Inner Harbour.

Crib Point site assessment

Crib Point Jetty is an existing operational industrial jetty within Western Port that has been undertaking petroleum related activities for more than 50 years. Crib Point provides:

- An existing jetty with berth capacity and of a suitable size to accommodate the FSRU. At the time of initial screening, Western Port was receiving 167 ship calls annually, over 100 of which were oil and gas tankers.
- A deep-water shipping channel with a wide stretch of water between the Crib Point Jetty on the mainland and French Island (also known as the swing basin). These factors provide additional safety for vessels in an emergency.
- A naturally deep-water port within a sheltered bay (Western Port), with a maintained berth depth of approximately 13 metres at the lowest tide level, with an additional three metres during high tides.
- No capital dredging²⁰ would be required for the Gas Import Jetty Works.
- An existing, dedicated berth (Berth 2) that is not currently being used.
- The capacity to double-berth an LNG carrier, around 300 metres in length, alongside the FSRU.
- A sheltered berthing location allowing safe ship-to-ship transfer when double berthed during changing wave conditions. The Crib Point Jetty has been previously used for ship-to-ship transfers of crude oil.
- An existing operational industrial marine facility, providing for the further development of maritime industry activities.
- Land use zoning provisions appropriate to the use of the jetty and adjacent landside area that has been reserved via planning schemes for port and related uses under the Mornington Peninsula Planning Scheme, providing ample safety buffers.
- Proximity to AGL's largest gas demand centre, Victoria, of which greater than 70 per cent of peak gas day demand is within the Melbourne metropolitan area.
- Use of existing gas transmissions networks without major pipeline modifications to supply the south-eastern gas markets.

²⁰ Capital dredging relates to the activity of creating new civil engineering works by dredging, such as harbour basins, and the deepening of existing waterways including approach channels.

Assessment of operability

An assessment of operability at the proposed shortlisted sites was undertaken, considering the ability to keep the FSRU in a safe and reliable functioning condition with respect to existing operational requirements. Overall Crib Point is considered to have the best operability, followed by Port Adelaide with Port Kembla the most challenging location. **Table 2-4** presents a summary of the various operability factors considered.

Table 2-4: Assessment of operability

Option/criteria	Port Adelaide	Port Kembla	Crib Point
Anchorage near port facility	Sheltered anchorage areas available near port	The relevant port authority does not recommend anchoring near Port Kembla due to poor holding ground	Sheltered anchorage available near port
Access to port facility via port waters	Channel and turning basins below The World Association for Waterborne Transport Infrastructure (PIANC) guidelines but acceptable after dredging	Limited turning space and may be subject to future development by the AIE	Good access, wide turning basin and depth to seabed
Existing tug capacity	Sufficient tugs available	Marginal existing tug capacity available to cater to existing shipping requirements	Additional tugs required
Ground conditions	No rock armour utilised. Soft ground will mitigate damage if LNG carrier runs aground	Rock armour utilised along banks within harbour and therefore increases risk of damage if LNG carrier runs aground	No rock armour utilised. Soft ground will mitigate damage if LNG carrier runs aground
Wind and swell	Within acceptable limits	Outer Harbour subject to some swell. Wind exceeds 25 knots mid-afternoon in Sept – Dec	Within acceptable limits
Interaction with port traffic	<ul style="list-style-type: none"> • Average of four ships per day pass berth • Restricted during LNG carrier movements • Passing ship study required to assess surge • Recreational traffic a concern 	<ul style="list-style-type: none"> • Average of five ships per day pass berth • Restricted during LNG carrier movements • Passing ship study required to assess surge • Negligible recreational traffic 	<ul style="list-style-type: none"> • Broad channel with less than around one commercial ship per day • Recreational traffic within Western Port, however large swing basin provides sufficient space for bypassing recreational vessels
Risk of collision with other ships	Low	Moderate – berth located near confined turning basin	Low
Unassisted/emergency departure	Possible under some conditions	Not possible	Possible
Zoning under Planning Schemes	Compatible with proposed facility	Not compatible with proposed facility	Compatible with proposed facility

2.5.3 Rationale for selecting Crib Point

Victoria was selected as the location for the Project because it has the largest gas market by volume consumed in south-eastern Australia. The gas import jetty would be located at the existing Crib Point Jetty within the Port of Hastings. The port is a commercial port within Western Port with an existing deep-water channel and berth developed to support international trade.

The Port of Hastings serves international shipping operations, with an average of 190 vessels a year for the past 20 years. Products imported and exported through the port include crude oil, ethanol, liquefied petroleum gas (LPG) and steel.

Industrial activities have occurred in the vicinity of the Crib Point Jetty for more than 50 years. The jetty is currently operating as a working industrial site with two berths for mooring vessels. Berth 1 is used by United Petroleum to transfer liquid fuel to its onshore storage facility located near Hastings. Berth 2 is currently decommissioned.

The Project proposed at Crib Point Jetty is compatible with the development and use of the port in the Port Zone (PZ) under the Mornington Peninsula Planning Scheme and State Planning Policy Framework. The jetty provides a large deep-water shipping port and a wide swing basin to enable the safe passage of vessels as well as exclusive access to a berth capable of accommodating vessels measuring up to 300 metres long, with separation from adjacent berths.

The Project location has been optimised to best benefit Victoria by minimising the distance that gas needs to be transported, reducing the cost of gas to market customers.

Locating the Project on the eastern side of Melbourne was considered optimal as it provides access to the Longford-to-Melbourne pipeline, which is the main gas transmission pipeline supplying Melbourne. The Project would help offset the decline in domestic production that has historically filled this pipeline and avoid bottlenecks on the smaller pipelines to the west of Melbourne, while facilitating diversion of gas supply towards the Eastern Gas Pipeline to supply gas to New South Wales.

Port locations in Victoria, South Australia and New South Wales were also investigated but lacked the required depth or infrastructure to accommodate a continuously moored FSRU.

2.6 Pipeline options

This section provides an explanation of the selection process for the pipeline alignment, including gas pipeline options considered as part of the development of the Pipeline Works.

2.6.1 Pipeline infrastructure

The VTS is operated by the Australian Energy Market Operator (AEMO) and links multiple gas producers, as well as major gas users and gas retailers across Victoria. The proposed pipeline is required to connect into the VTS due to its ability to cater for high volumes of gas at high flow rates, and to enable gas to be transported within Victoria, across to South Australia, and up to New South Wales.

The local gas network has been developed over time to service industrial and residential gas users. Development of the potential pipeline option initially included use of the existing pipeline infrastructure, but it was determined that the existing local gas network does not have the requisite size, pressure or capacity in this location to allow for the transmission of gas from a new supply point to the VTS.

It is not economically feasible to transfer the quantity of gas proposed to be imported as part of the Project by road or rail. This would also result in potentially unacceptable environmental outcomes, such as substantial increases in emissions from heavy vehicles using the public road network, and increased safety risks. As such, a new pipeline is required to connect high volumes of gas at high flow rates to the VTS to enable gas to be transported around Victoria.

In selecting the pipeline alignment, APA has undertaken a detailed assessment of alternatives in consideration of the objectives of the Project. Third party reports completed by IDM Partners Pty Ltd in 2017 and 2018 detail the possible pipeline alignment options. This process included consideration of pipeline alignments from Crib Point to proposed connection locations on the VTS and considered environmental, safety, social, constructability and cost constraints (see **Section 2.6.3**).

Since the preparation of these studies and following the selection of the pipeline alignment, APA has refined the alignment through a process of 11 design revisions. These design revisions primarily responded to issues raised by stakeholders and the ability to control, mitigate and manage potential environmental, social, economic and safety impacts from pipeline construction and operation.

2.6.2 Alignment selection process

The pipeline alignment identification and selection requirements are set out in Australian and New Zealand Standards AS/NZ 2885.1: 2018 Pipelines - Gas and Liquid Petroleum Design and Construction. The Australian Pipelines and Gas Association (APGA) Code of Environmental Practice: Onshore Pipelines provides industry accepted guidance on environmental management through the planning and acquisition, construction, operation and decommissioning phases of a pipeline's lifecycle.

The requirements set out in the AS2885.1 and the Code of Environmental Practice form part of the detailed assessment process undertaken to determine the preferred pipeline alignment between Crib Point Jetty and the connection to the VTS. **Section 2.5.3** describes how the Crib Point site was identified and **Section 2.6.3** outlines how the location of the connection point in Pakenham was determined.

The following environmental, social, economic and safety values were considered in the identification of pipeline alignment options:

- pipeline length
- number of land parcels and landowners affected by the preferred pipeline alignment
- existing land use
- complex terrain and mobile landforms, such as sand dunes
- national parks, state parks, conservation reserves and flora reserves where right of way (ROW) does not exist or is not achievable, for example the Western Port Ramsar site
- threatened ecological communities and threatened species habitat (where possible)
- waterbodies and wetlands and, where possible, provision of adequate separation to watercourses prone to channel avulsion or downstream bend migration, particularly outside bends
- existing infrastructure, such as stock watering infrastructure and stockyards
- known sites of cultural significance
- potential future land use development as identified in the Pakenham East Precinct Structure Plan (PSP)
- presence of good to high quality agricultural land
- transport networks
- proximity to houses, schools, nursing homes and hospitals
- potential for co-location with existing linear infrastructure

- constructability – the ability to construct the pipeline including issues such as:
 - access
 - workspace and stringing space for horizontal directional drills or horizontal bores
 - a 30-metre-wide construction ROW to safely accommodate the equipment and personnel during each pipeline construction phase including space for stockpiling of topsoil and trench material so it can be later used to backfill and rehabilitate the area.
 - potential for relocation of existing services
 - potential for reinstatement and rehabilitation of the easement post construction
 - disruption to businesses and agricultural activities
 - potential to encounter contaminated land
 - soils, landforms and watercourses
- ability to achieve perpendicular crossings of existing railway and third-party underground infrastructure
- limiting exposure to steep and side slopes
- third-party damage
- accessibility for pipeline operation
- public and worker safety (during construction and operation).

APA selected the pipeline alignment based on the above parameters taking into consideration the key constraints and opportunities afforded by existing and proposed land use and infrastructure in consultation with landholders and other stakeholders, with reference to the overarching considerations of public safety, and potential environmental, social and economic impacts of the proposed pipeline.

2.6.3 Pipeline alignment selection

The environmental, social, economic and safety values detailed in **Section 2.6.2** were used in conjunction with the statutory requirements for alignment selection to identify and review multiple pipeline alignment options from Crib Point to the VTS connection east of Pakenham.

An independent consultant, IDM Partners Pty Ltd, was engaged to complete a desktop assessment of the potential pipeline alignment options between Crib Point Jetty and the VTS. The desktop assessment consisted of compiling a project geographic information system (GIS) to undertake a constraint-based analysis and identify a shortlist of the most favourable alignments.

The constraint analysis identified two potential corridors for the proposed pipeline from the Crib Point Jetty:

- a western corridor running direct from Crib Point Jetty through Hastings township to APA's existing Dandenong South LNG Facility
- an eastern corridor, which consisted of onshore and offshore options to the existing Dore Road Mainline Valve (MLV), near Pakenham.

The western and eastern corridors are shown in **Figure 2-21**.

The outcomes of the GIS constraint-based analysis were used to identify alignment options within the western and eastern corridors. The constraint levels that were used were no-go, high, medium, low and very low. The levels are as follow:

- No-go: National, coastal and marine parks, conservation parks, flora and fauna reserves, residential and commercial areas, existing and future marked development areas, critically endangered flora and fauna, ecological communities, lots less than 1,000 square metres
- High: reserves, rural residential areas, rare and vulnerable flora and fauna, lots greater than 1,000 square metres and less than 4,000 square metres
- Moderate: Industrial zoned land, vulnerable ecological communities, major roads (highways and freeways), transport corridors, lots greater than 4,000 square metres and less than 10,000 square metres
- Low: least concern ecological communities, low grade roads and lots greater than 10,000 square metres and less than 20,000 square metres
- Very Low: lots greater than 20,000 square metres.

A total of eight alignment options were identified, two through the western corridor and six through the eastern corridor. The IDM report classified the Western Port Ramsar site as a 'high' constraint, based on the above criteria. Pipeline alignments through areas classified as high are technically possible but are less preferable due to potential impacts to the identified environmental, social, economic and safety values.



Geographic information system (GIS)

GIS is a computer system for capturing, storing, checking and displaying data related to positions on Earth's surface to better understand spatial patterns and relationships.

The following sections describe in more detail the alignment option considerations for each of the identified pipeline corridors.

Pipeline alignment options to Dandenong South

APA assessed two pipeline alignment variants between Crib Point and APA's Dandenong South LNG Facility (Route name: CP-DNG#1). These alignments included:

- route to APA's Dandenong South LNG Facility via Frankston–Flinders Road, Elgas easement and Dandenong Valley Highway (Alignment name: CP-DNG#1a)
- route to APA's Dandenong South LNG Facility via Frankston–Flinders Road, Elgas easement and Bayliss Road, Taylors Road and Eastern Contour Drain to Dandenong Valley Highway (Alignment name: CP-DNG#1b).

Assessment of options to Dandenong South

The corridor to APA's Dandenong South LNG Facility was initially considered to be the preferred option as it is the shortest pipeline alignment. However, further investigation and field verification identified this corridor as highly constrained, due to the pattern of development, urban growth and industrial subdivision in these areas. The social impacts associated with land use and tenure would have resulted in a high impact to these existing communities during construction.

There are existing linear infrastructure corridors including oil and gas pipeline corridors between Crib Point/Hastings and Dandenong South. These corridors are occupied by existing assets and the ability to widen the corridors to co-locate with this infrastructure is limited due to adjacent land uses.



▲
Figure 2-21: Pipeline alignment options

The assessment of options to Dandenong South determined that the construction of the pipeline to Dandenong South would result in significant disruption to traffic, businesses and third-party asset owners. Modifications to the Dandenong South LNG Facility are also constrained due to its location in an urban area, within the Urban Growth Boundary. For these reasons, it was identified that this alignment would create unacceptable risk to the achievement of the Project objectives and to nearby land uses and sensitive receptors.

Pipeline alignment options to Pakenham

APA assessed several alignments between Crib Point and APA's proposed connection to the VTS at Pakenham (discussion on the process undertaken to identify a suitable connection point to the VTS is included in **Chapter 3** Project development).

APA considered six alignments between Crib Point and the VTS connection at Dore Road:

- Alignment via Deep Creek following the existing Elgas easement from Crib Point through the southern limits of Hastings township to Dore Road. (Alignment name: CP-DR#1)
- Alignment via Stony Point rail line following the same alignment as CP-DR#1 but it utilised the rail corridor through Hastings. (Alignment name: CP-DR#2)
- Alignment via Cardinia using the same alignment as CP-DR#1 to the northwest of Tooradin where it deviated from the ESSO pipeline easement and ran directly to Ballarto Road where it joined alignments CP-DR#1 and CPT-DR#2. (Alignment name: CP-DR#3)
- Alignment via Western Port (an on and offshore alignment). The offshore section of the alignment used the main channel in Western Port North Arm and then smaller channels to reach the Dalmore Drain southwest of Koo Wee Rup where it tracked west of the town before turning north to join the Bass Gas Sales Pipeline south of the former Gippsland rail line. The alignment then adopted the same corridor as CP-DR#1 to Dore Road (Alignment name: CP-DR#4).
- Alignment via Mt Ararat Road to Dore Road using the same route as CP-DR#3 until it reached Bald Hill Road and ran south of the former Gippsland rail line. Once it reached Mt Ararat Road, this alignment turned north to cross the operational Cranbourne to Pakenham rail line, Princes Freeway and Princes Highway to Dora Road (Alignment name: CP-DR#5).
- Alignment via Cardinia and port land adopted the same alignment as CP-DR#3 except in the area east of Tyabb. This option to the east of the existing corridor uses open agricultural land and property boundaries to avoid congested infrastructure easements (Alignment name: CP-DR#6).

This was refined to five following a desktop assessment against the relevant alignment selection criteria and field verification of the pipeline alignments (see **Figure 2-21**). These pipeline alignment options were:

- Crib Point to the Dore Road Mainline Valve (Alignment name: CP-DNG#3)
 - Alignment to Dore Road MLV via Hastings foreshore, Esso easement, Cardinia and Bass Gas Sales Pipeline (Alignment name: CP-DR#3a)
 - Alignment to Dore Road MLV via Hastings foreshore, Esso easement, Cardinia, east of Mt Ararat Road and APA VTS pipelines (Alignment name: CP-DR#3b)
 - Alignment to Dore Road MLV via Hastings foreshore, Tyabb Terminal Station deviation, Esso easement, Cardinia, east of Mt Ararat Road and Bass Gas Sales Pipeline (Alignment name: CP-DR#3c)
 - Alignment to Dore Road MLV around Hastings (western option), Esso easement, Cardinia and Bass Gas Sales Pipeline (Alignment name: CP-DR#3d).
- Crib Point to the Dore Road Mainline Valve (offshore) (Alignment name: CP-DR#4)
 - Alignment through Western Port to near Koo Wee Rup and then north to Dore Road MLV via either Bass Gas Sales Pipeline or the alignment option to the east of Mt Ararat Road (Alignment name: CP-DR#4a).

Assessment of pipeline alignment options to Pakenham

The assessment identified that land-based alignments CP-DR#3a, CP-DR#3b, CP-DR#3c and CP-DR#3d to Dore Road MLV were the most favourable pipeline alignments, with more flexibility to avoid identified constraints and lower constructability risk.

The offshore pipeline alignment (CP-DR#4a) was considered the least favoured alignment due to potential impacts on the Western Port Ramsar site and significant costs associated with construction, operation and maintenance of offshore pipelines.

Pipeline alignment CP-DR#3d was considered less favourable than the other CP-DR#3 alignments due to potential significant impact on higher value land uses (including lifestyle and rural living properties, orchards, vineyards and hobby farms) and a potential greater impact on conservation areas, specifically the Ted Harris Walk, a Trust for Nature property compared to other alignments.

Pipeline alignment CP-DR#3b was identified as the preferred pipeline alignment as it traverses mainly grazing land and uses existing pipeline corridors, while avoiding congested road reserves, rail yards and areas of high value intensive agriculture. Pipeline alignment CP-DR#3b minimises potential impacts on existing landowners and occupiers. This pipeline alignment also avoids potential impacts on existing and future land use, including avoiding land within the Pakenham East residential and commercial development (also known as the Pakenham East Precinct Structure Plan).

This preferred alignment has been subject to further assessment, refinement and design, with changes resulting from the incorporation of engineering, environmental and cultural heritage investigations and engagement with relevant stakeholders. APA subsequently undertook engagement with affected parties to further validate this pipeline alignment with consideration of specific impacts to individual properties. The pipeline alignment refinement is an ongoing and iterative process as information becomes available and more is known about the land proposed to be intercepted.

The pipeline alignment has been subject to 11 design revisions, incorporating multiple line changes based on mitigation of environment, social, economic, safety and constructability issues.

As part of the continual review of the alignment, APA reviewed alignment options that were previously discounted or not fully assessed, to validate the pipeline alignment in relation to other potential alignments. A significant assessment was undertaken for a number of pipeline alignments that sought to co-locate with the drainage and spoil bank systems in the Koo Wee Rup-Longwarry Flood Protection District with these options being inferior to the pipeline alignment due to the difficulties in co-locating gas pipelines with other linear infrastructure from a safety perspective. These options have been referred to as the Tarago Water Supply Main and the Drainage and spoil bank systems options and are discussed in more detail below.

Environmental, social, economic and safety aspects of consideration

Pipeline alignment selection is one of the primary mitigation tools in avoiding and reducing potential environmental, social, economic and safety impacts associated with linear infrastructure. The following sections summarise the key aspects of the pipeline alignment investigations undertaken by APA as part of the assessment of the pipeline alignment.

Co-location with other linear infrastructure

The pipeline would be co-located with existing infrastructure and transport corridors in a number of areas. The pipeline alignments assessed had similar levels of co-location and the alignment selection process benefited from a number of existing linear easements and reserves for which the pipeline could be co-located. These include:

- oil and gas pipeline corridors: Esso Australia (Crib Point to Long Island Point; Hastings to Altona; Long Island Point to Longford), Elgas (Crib Point to Dandenong); Australian Gas Networks (Crib Point to Dandenong), Viva Energy (Crib Point to Dandenong) and United Petroleum (Crib Point to Hastings)
- water infrastructure (Melbourne Water): Tarago Water Supply Main pipetrack reserve and various drainage and levee bank systems
- rail infrastructure: Stony Point rail line and the Gippsland rail line
- road network: both locally controlled and state-controlled roads (by VicRoads).

APA and other gas infrastructure providers are generally limited in co-locating steel pipeline assets in parallel and close proximity to overhead transmission lines for long distances. These corridors are therefore avoided due to interference with the performance of the pipeline's cathodic protection system. APA initially assessed co-location opportunities with the Cranbourne Terminal Station to Tyabb Terminal Station 220 kV Transmission Line (Alignment CP-DR#3b). This assessment noted induction issues that would require additional engineering treatment to minimise voltage interference, with long-term management requirements. This pipeline alignment was further constrained due to the inability to access the Melbourne Water pipetrack reserve (see further discussion below) and small landholdings and residential development around the corridor east of Tyabb.

Co-location with linear infrastructure has certain limitations and generally refers to the pipeline alignment being located immediately adjacent to existing infrastructure corridors. Existing infrastructure owners generally own land or have an easement in their favour to allow that entity to safely operate, maintain and potentially replace or expand their infrastructure as necessary. Due to this, co-location within these existing corridors (and certainly within existing easements) is not always achievable. The preferred pipeline alignment is adjacent to existing infrastructure corridors for as much of the proposed length as possible.

The following sections identify several areas of potential co-location adjacent and/or within other linear infrastructure corridors.

Stony Point rail line (between Crib Point and the north of Hastings)

The pipeline alignment has been moved from the Frankston-Flinders Road corridor to the Stony Point rail corridor between Reid Parade and Hodgins Road within Hastings, to significantly reduce potential amenity impacts to the Hastings community during construction (compared to the earlier iteration that considered construction along Frankston-Flinders Road through Hastings).

From Hodgins Road to north of Graydens Road (KP7.35 to KP9) the pipeline alignment is proposed to traverse along the council paper road adjacent to the rail corridor. A paper road is a term used for a road that is legally established and recorded in survey plans however, has not been constructed.

The Stony Point rail corridor is generally 30 metres wide and is an operating rail asset with regular services between Frankston and Stony Point. The rail corridor supports several oil and gas pipelines (Australian Gas Networks, Elgas and United Petroleum). Works within the operating rail reserve would be conducted in accordance with relevant safety requirements.

The refinement of the pipeline alignment through Hastings has resulted in the use of the Stony Point rail corridor where feasible (i.e. where the rail corridor is wide enough to allow for safe construction), minimising the requirement to construct the pipeline along Frankston-Flinders Road. As set out in the studies conducted for the EES, the use of the Stony Point rail corridor would significantly reduce potential amenity impacts on nearby sensitive receptors and local businesses.

Tarago Water Supply Main pipetrack reserve (Hastings to Pakenham South)

The Tarago Water Supply Main pipetrack reserve was considered for the pipeline alignment due to the existing 20-metre-wide Melbourne Water easement (see **Figure 2-22**). The easement contains a single water pipeline asset (1,200 millimetres in diameter), presenting potential opportunity for co-locating infrastructure. Co-location within this easement was identified as having the potential to damage existing Melbourne Water infrastructure during construction.

In addition, consultation between APA and Melbourne Water identified that the Melbourne Water pipeline has been identified for replacement within the foreseeable future. The use of this existing easement for a gas pipeline would have the potential to constrain these replacement works.

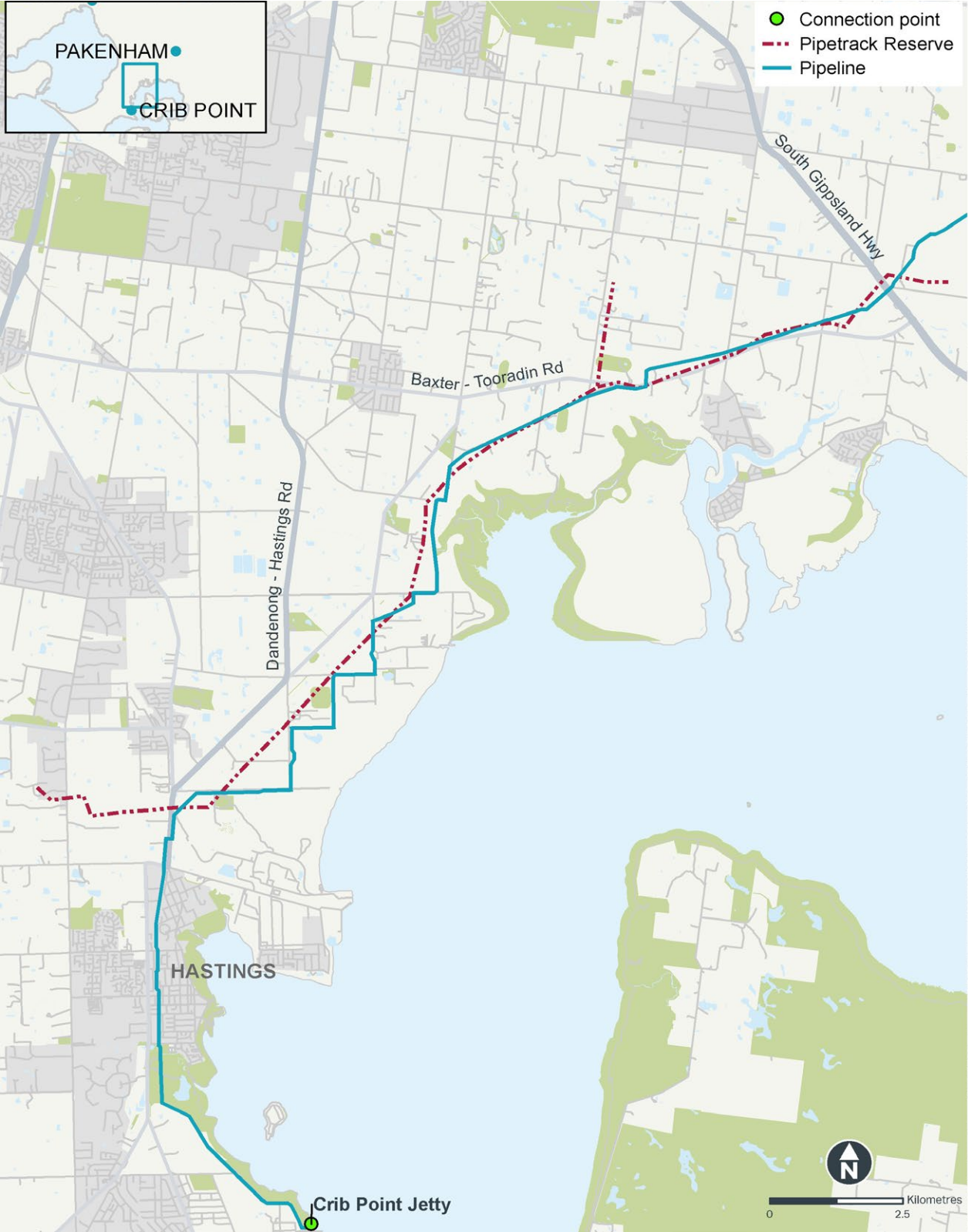
The Melbourne Water easement also presented a number of unworkable constraints around safety and integrity of the Melbourne Water asset (particularly relating to branch connections and pipeline fixtures). The risk of impacts on the Melbourne Water asset during pipeline construction were identified as having the potential to impact on Melbourne's water supply.

The Melbourne Water easement has rural residential developments abutting the easement as well as occupying large parts of the easement. The easement does not strictly align with property boundaries and there are a large number of properties over which the easement applies. The use of this Melbourne Water easement for installation of the proposed gas pipeline would therefore result in potential impacts on a significant number of landholders.

Esso Australia oil and gas pipelines (north-west of Tooradin to Deep/Toomuc Creek)

APA is unable to co-locate the pipeline within the existing easement in favour of Esso Australia due to the physical space requirements of this easement, the issues of working over aging pipeline assets and commercial considerations between different infrastructure entities.

Consideration was given to (locating immediately adjacent to) the existing pipeline corridor for nine kilometres. It was considered that this alignment would have a greater impact to smaller landholdings and increased the impact of construction on areas of high-value agricultural production prior to reaching the drainage reserve. The pipeline alignment is proposed north of these areas of high-value agricultural production within larger land parcels with less intensive agricultural production (for example, grazing and fodder harvesting).



▲
Figure 2-22: Tarago Water Supply Main pipetrack reserve option

Drainage and spoil bank systems (Koo Wee Rup-Longwarry Flood Protection District)

The option of co-locating the pipeline within the existing drainage/spoil bank reserves maintained by Melbourne Water was considered (see **Figure 2-23**).

APA undertook a constructability assessment and determined that in the upper reaches of the drainage system (particularly Deep Creek) there is insufficient working space to efficiently and safely construct the pipeline. The wider areas of the Deep/Toomuc/Cardinia Creek reserve have sufficient working space to construct the pipeline. However, consultation with Melbourne Water identified that the integrity of the spoil bank system is integral in preventing localised flooding and construction may endanger public and asset safety in high flow/flood conditions.

An assessment of the ecological values of waterways associated with the drainage and spoil bank system identified to the potential for impacts on key habitat of listed threatened species, including Growling Grass Frog and Southern Brown Bandicoot. Potential impacts on this valuable habitat was identified as an additional constraint. Melbourne Water actively undertakes a program of works to improve habitat for key regionally threatened species within these corridors, which provide connectivity and valuable habitat. The drainage reserves are recognised in local and state planning provisions as being of ecological significance.

Further, a key consideration in the assessment of the viability of this proposed alignment was the potential impact on high quality agricultural land, particularly intensively farmed land including vineyards, orchards and horticultural enterprises. Relevant local planning policies applicable to this land reflect the important economic value of agricultural land in this region, with key strategies to protect soil-based agriculture. Construction and operation of a pipeline, including the requirement for the establishment of an easement, was deemed to be inconsistent with these policies.

Road network: local roads and VicRoads managed roads (multiple locations)

Where there is a viable alternative pipeline alignment available, public land is generally avoided as there is a risk of damage to a pipeline in an area of high use, where other services are located, and regular excavation can occur. As a first control against external interference with the pipeline, the pipeline is safer when on private land and protected by way of an easement.

In addition, road reserves often contain the largest tracts of remnant native vegetation and habitat for species of conservation significance (for example, Southern Brown Bandicoot) due to historic clearing of adjoining agricultural areas.

The areas with significant vegetation or habitat assessed and considered as part of the comparative assessment included Frankston Flinders Road (Stony Point Road to Reid Parade), Tyabb-Tooradin Road, Baxter-Tooradin Road, Lynes Road and Muddy Gates Lane and McDonalds Drain Road.

Beach Energy Bass Gas Sales Pipeline (Pakenham South)

The co-location of the pipeline with Beach Energy's Bass Gas Sales Pipeline (authorised under Pipeline Licence No. 244) from Bald Hills Road, Pakenham South was considered (see **Figure 2-24**). This pipeline alignment continues from this location through the Pakenham East rail depot and land identified in the recently released Pakenham East Precinct Structure Plan (PSP) to the APA operated Dore Road MLV. The Pakenham East PSP north of the Princes Freeway and the rail stabling yards substantially constrain land availability for a pipeline and associated facilities in this location.

Western Port Ramsar site

The majority of the pipeline alignments assessed by APA intersected the Western Port Ramsar site to varying degrees. These alignments proposed the use of construction methodology that minimised potential impacts on the environmental values and ecological character of the Western Port Ramsar site.

The proposed pipeline alignment intersects the Western Port Ramsar site at two locations:

- Warringine Park
- Watson Creek.

Following an initial ground-truthing exercise and further assessment by APA, complete avoidance of the Western Port Ramsar site within the area of Warringine Park was unachievable. Pipeline alignments in this location were assessed as having potentially unacceptable impacts on the peri-urban land uses in the vicinity of Hastings and/or would require significant and ongoing disturbance to the public road network, with resulting impacts on traffic, transport and access to properties and businesses. On selection of the alignment for the pipeline, APA assessed and determined that underground horizontal directional drilling (HDD) methodology would be employed to avoid surface impacts on the Ramsar site within Warringine Park.

Similar constraints applied to pipeline alignments that completely avoided crossing Watson Creek. In particular, the alignment south of Watson Creek (through and to the north of Hastings) that avoids Watson Creek would require the pipeline to deviate west, where it would conflict with multiple established land uses. HDD would also be used to avoid surface impacts on the Ramsar site at Watson Creek.

One pipeline alignment assessed by APA (Alignment CP-DR#4a) included a sub-sea pipeline from Crib Point to a location near Koo Wee Rup, which intersects the Western Port Ramsar site for approximately 29 kilometres. This pipeline alignment would impact on significantly fewer land parcels than other land-based options but was discounted due to the potential negative impacts on the ecological character of Western Port, as well as the significant costs associated with the construction, operation and maintenance of high-pressure sub-sea gas pipelines.

Other areas of environmental and social sensitivity

Warringine Park is discussed above in relation to the Ramsar designation, which occurs across part of the reserve. It is acknowledged that the reserve is of high conservation value more generally with important habitat for Swamp Skink and Southern Brown Bandicoot. All pipeline alignments assessed through Warringine Park were proposed to the western extent adjacent to the existing linear pipeline corridor. At this location the alignments are located in swamp scrub and grassy woodland ecological vegetation communities in the south and western part of the reserve, with no impact on coastal saltmarsh or mangrove communities.

Co-location of the pipeline with the existing pipeline corridor (Australian Gas Networks, Elgas, Viva Energy and United Petroleum) in this area is an outcome of the comparative assessment of constraints associated with accessing the Stony Point rail line (see above), potential impacts to mature native vegetation and operation of Frankston-Flinders Road south of Hastings.

Around Hastings, pipeline alignments were assessed that extended east along Reid Parade and along the Hastings foreshore (Western Port Coastal Reserve) (CP-DR#3b) and west from Reid Parade and to the west of Hastings (CP-DR#3d). The Hastings foreshore has been developed for a marina, carparks, playgrounds, recreation facilities, restaurant and visitors centre and construction of the pipeline through this area (alignment CP-DR#3b) was assessed to have a high community and social impact. This assessment was confirmed through preliminary consultation with Mornington Peninsula Shire. In addition to this, approximately 700 metres of the pipeline alignment would cross coastal saltmarsh communities within the boundary of the Western Port Ramsar site. The pipeline alignment construction and operation would not impact the coastal saltmarsh and mangrove communities in the park.

The pipeline alignment (CP-DR#3d) that runs west of Hastings to avoid potential impacts on the road network of Hastings (Frankston Flinders Road) and the Hastings foreshore, encounters more lifestyle and rural living properties, orchards, vineyards and hobby farms and would have significant impacts on these land uses.

This alignment would also increase the length of the pipeline within conservation areas and associated vegetation removal when traversing the Ted Harris Walk (between Frankston Flinders Road and Hendersons Road). As a result of the assessment to avoid impacts on residents and land uses, the pipeline alignment in Hastings would run along Frankston Flinders Road corridor and Stony Point rail corridor where the corridor widths allow safe construction.

Public safety

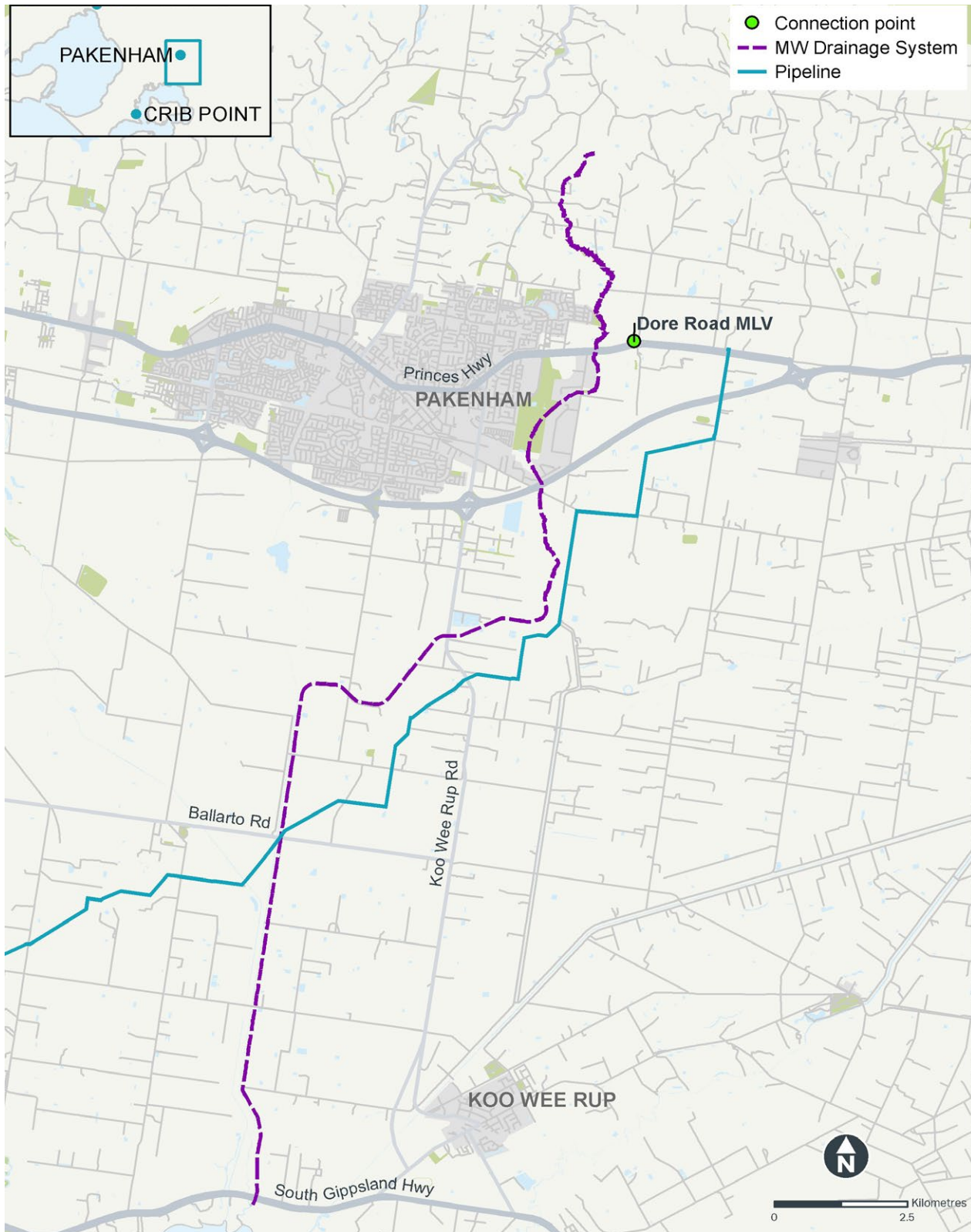
Public safety is a key consideration in pipeline construction and operation. Pipeline design must consider existing and reasonably foreseeable land use and proximity to sensitive receptors. In particular, avoiding areas where potential interference with the pipeline may occur is essential to ensuring public safety. Avoidance and separation are the principal mitigation responses. Areas where interference may occur are avoided and distances between sensitive receptors and the pipeline are maximised where possible. Additionally, adoption of additional physical, engineering and procedural controls to alert the public to the pipeline across its operational life is effective in reducing the risk to public safety to as low as reasonably practicable in line with the requirements of Australian Standards AS2885.1 Pipelines – Gas and liquid petroleum.

Due to the location of the pipeline alignments within and in close proximity to Hastings, those assessed occur within an environment that would be considered high density residential. In terms of pipeline design, these would require additional physical and procedural controls to protect against failure.

A selection of a pipeline alignment to Pakenham rather than Dandenong South is seen as preferable to limit exposure to existing high density and residential environments, which are a higher constraint on these pipeline alignments.

State and local planning frameworks have identified the future land uses along pipeline alignments to Pakenham. Such areas would predominantly remain for agricultural purposes; however, it is credible to consider that future residential development may occur over these pipeline alignments. From a public safety perspective, the alignments to Pakenham are less constrained than those to Dandenong South.

In addition, when considering urban development and sensitive uses around the pipeline at Pakenham South, the pipeline alignment is considered to have less impact from a public safety and design perspective to the other pipeline alignments that cross through the Pakenham East rail depot and traverse the Pakenham East PSP.



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Figure 2-23: Melbourne Water drainage system option

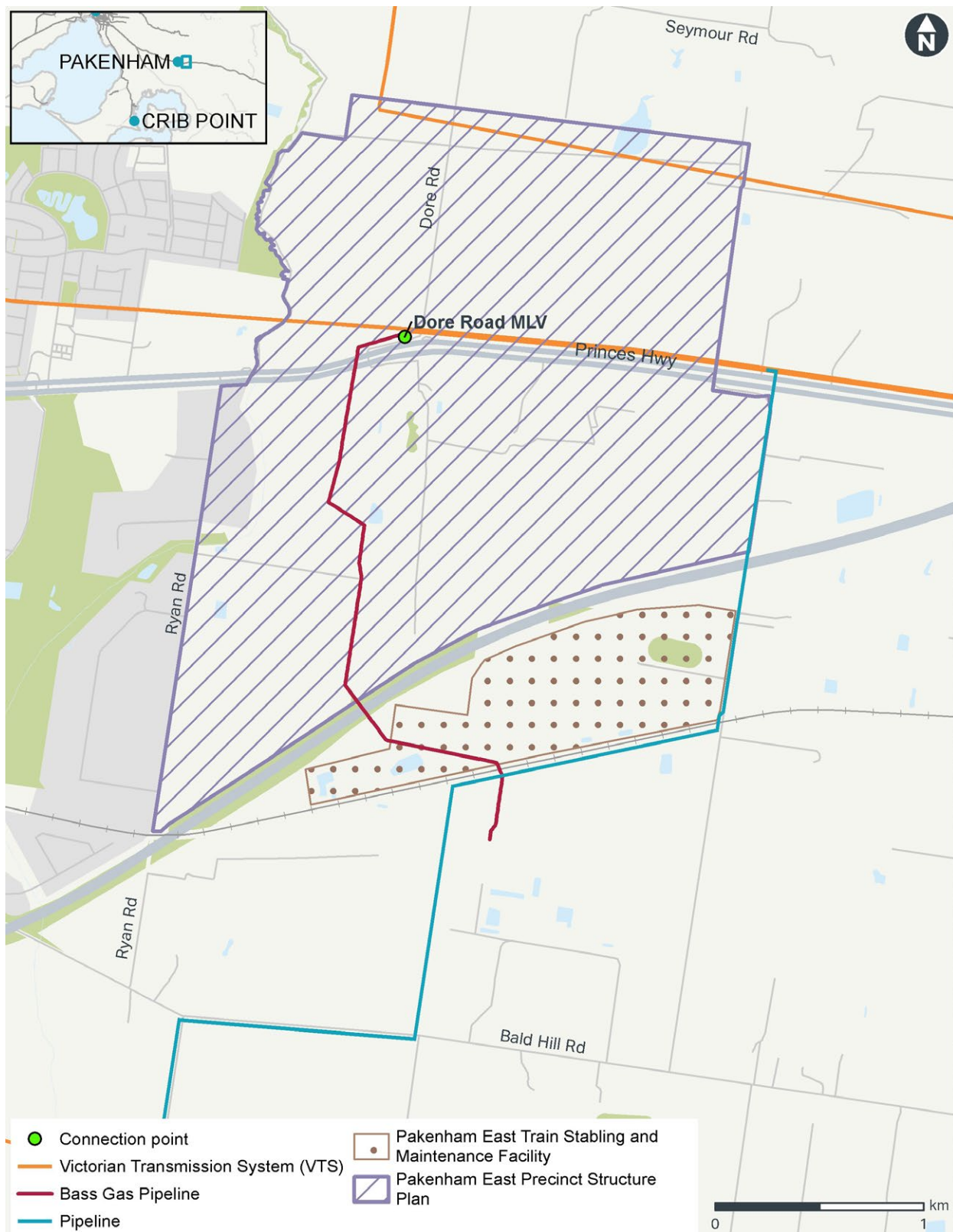


Figure 2-24: Melbourne Water drainage system option

2.7 Project rationale and benefits

This chapter has provided a detailed rationale for the Project, outlining why there is strong consensus in the energy sector that a gas shortage in the south-eastern states of Australia is looming, particularly the largest gas consumer of Victoria.

The Project would provide Victoria with an alternative and flexible source of natural gas from existing and new LNG projects in Australia and around the world and offers the potential to supply up to 160 PJ of natural gas per annum.

The Project would generate the following benefits for Victoria:

- help provide gas supply certainty and security for Victorian gas customers, and customers from other states that rely on Victoria's gas supply
- place downward pressure on gas prices for residential customers as well as vulnerable industrial and commercial customers, many of whom are large generators of employment
- provide a flexible source of gas for gas-powered generation so that customers have secure and stable electricity supply as the NEM transitions to accommodate more renewables.

The Project is expected to involve a capital investment of about \$250 million, although this is subject to change pending further project enhancement (or optimisation) and final investment decision. The Project is expected to employ in excess of 500 workers at the peak of its construction phase. The majority of the construction workforce would be specialists sourced from Victoria and interstate. Opportunities for local suppliers and employment would include a range of general trade and support services, such as:

- crew for the FSRU
- vegetation management, such as clearing, mulching and rehabilitation
- construction work for jetty upgrade, remediation and piling and ongoing maintenance
- catering and food contractors
- fencing contractors
- security guards and patrols
- grading, dozing and excavating
- water truck driving.

Once the Project was operating, it is expected that 40 permanent positions would be created at Crib Point. These roles, relating to running the FSRU, as well as security and support, would involve rotating shifts and accordingly, the 40 positions would in practice create employment for well in excess of 40 people.

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