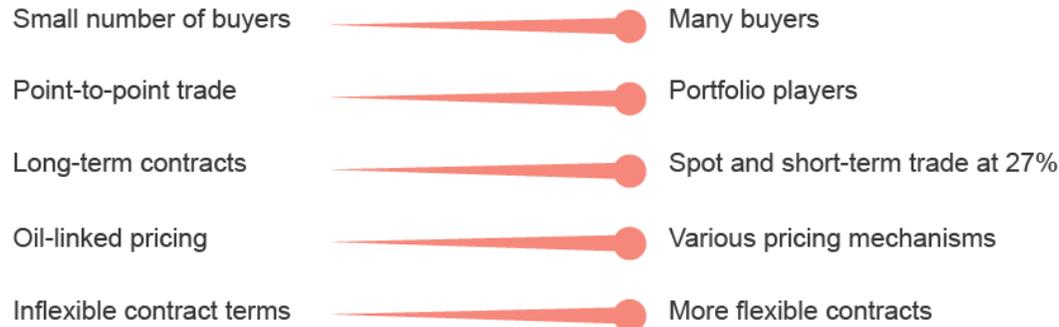


Asian LNG trade and Australian LNG imports

Resources and Energy Quarterly June 2018

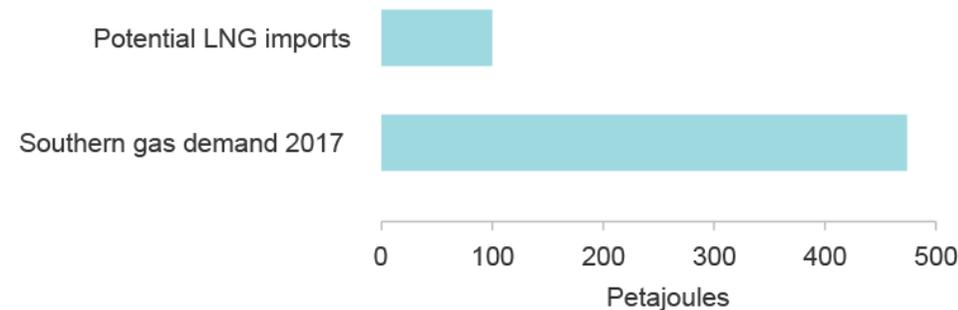
Asian LNG trade has changed



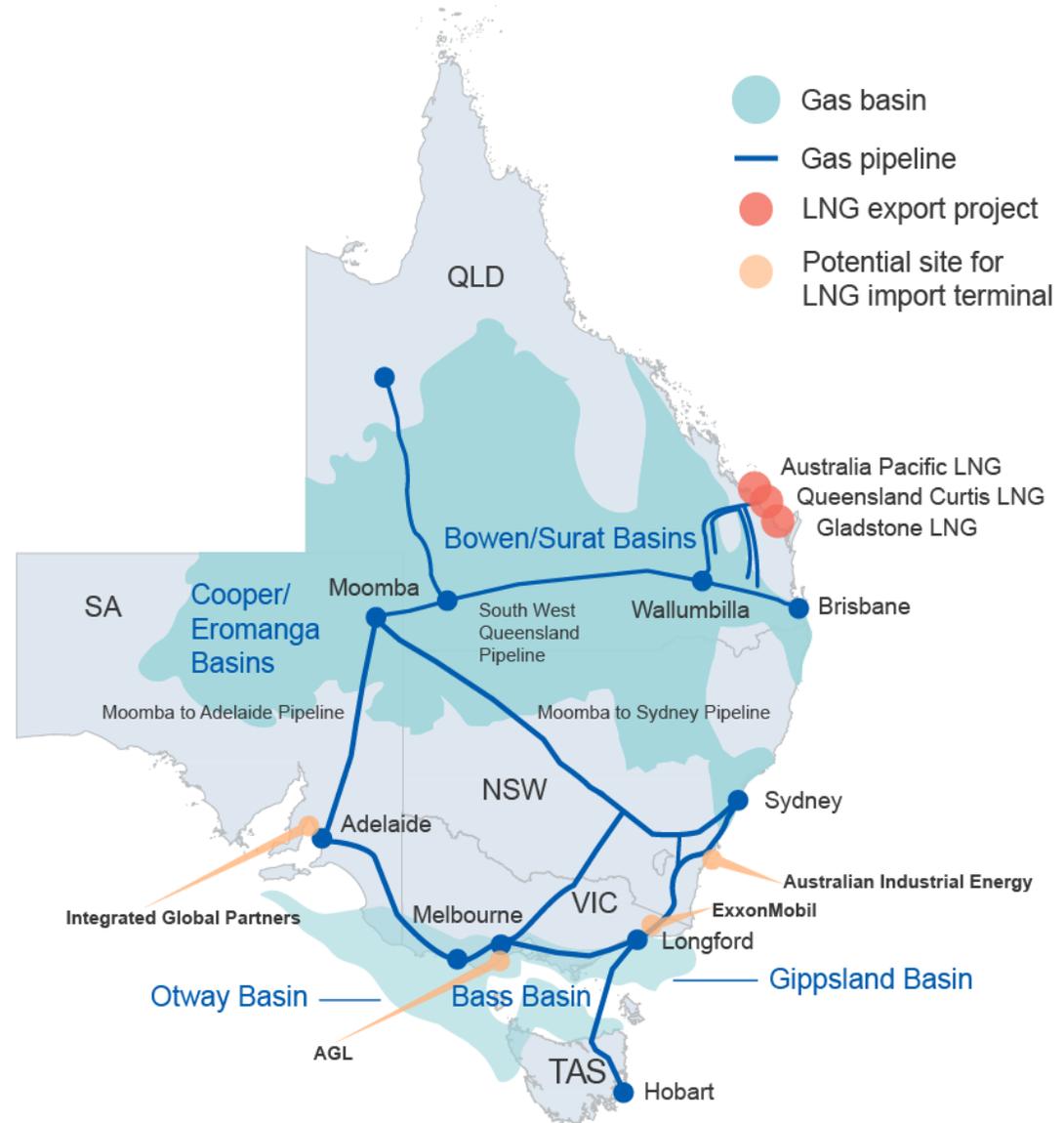
The case for LNG imports



Potential LNG imports and southern gas demand



LNG import proposals in Australia's east coast gas market



15.1 Introduction

Australia may well become the world's largest LNG exporter at the same time it becomes an LNG importer. Australia is on track to surpass Qatar as the world's largest LNG exporter around the turn of the decade. At the same time, there are four proposals for an LNG import terminal that could see LNG imports begin as soon as 2020.

Technological developments and changing business practices in the LNG industry have enabled countries like Australia to consider importing relatively small volumes of LNG. Before the turn of the millennium, LNG trade in Asia was characterized by a point-to-point business model, long-term contracts, oil-linked pricing and inflexible non-pricing contractual terms.

Around the turn of the millennium, LNG markets began to change. Floating Storage and Regasification Unit (FSRU) technology allowed buyers to start purchasing LNG more quickly and at a lower cost. Spot and shorter-term trading markets began to grow, providing buyers with access to different pricing arrangements, shorter contract lengths and more flexible contract terms.

There are several reasons why LNG imports into the southern part of Australia's east coast gas market are being considered. Southern production will potentially fall short of southern demand in coming years, and pipeline imports from Queensland are relatively expensive. Meanwhile, Asian LNG spot and short-term prices are expected to decline, at least in the short-term, as additions to global production capacity outweigh new demand.

However, challenges to importing LNG remain. Asian LNG spot and short-term prices are currently elevated, at levels above Australian domestic gas prices. It is possible that Asian LNG spot and short-term prices may not decline as far as some expect, or remain low for a protracted period of time. Meanwhile, purchasing commitments from a significant number of domestic buyers, or a large energy retailer, will likely be required to underwrite the economics of an LNG import terminal.

This chapter examines the issue of importing LNG into Australia's east coast gas market. Section 2 looks at how changes in the way LNG is traded have enabled countries to import small volumes of LNG economically. Section 3 examines why LNG imports into Australia's east coast gas market are being considered, and looks at proposals for an LNG import terminal. Section 4 discusses some of the key issues affecting the commercial viability of LNG imports into Australia.

15.2 Asian LNG trade

The LNG business model before 2000 was different to today's

Global LNG trade has changed substantially since it began in 1960s. LNG trade in Asia — which began in 1969, when Japan received its first cargo of the liquefied fuel from Alaska — has been no exception.

Before the turn of the millennium, the LNG business was characterized by point-to-point trade. The typical LNG project sold gas to a small group of buyers, with dedicated ships taking gas between the seller's liquefaction plant and the buyers' regasification terminals.

LNG was traded on long-term contracts, sometimes in excess of 20 years. LNG projects require a large upfront capital investment, and long-term contracts provided LNG project developers with the certainty of returns required to gain financial support from project lenders.

These long-term contracts often included inflexible terms on matters not related to prices. Destination clauses, for instance, prevented a buyer from reselling LNG cargoes until they were delivered to the buyer's port.

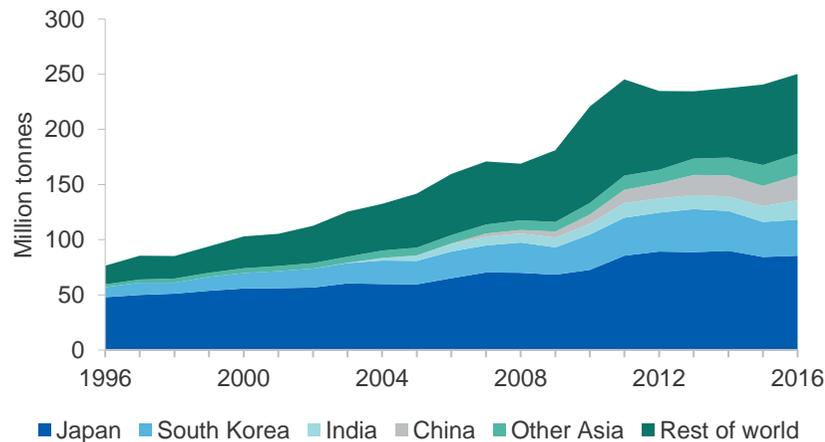
In Asia, LNG prices were linked to the price of crude oil. When Japan began importing LNG, oil was the main fuel competing with natural gas in power generation, and consequently an oil-price linkage was adopted in LNG contracts. When other Asian buyers entered the market — South Korea (1986), Taiwan (1990), India (2004) and China (2006) — they too adopted this pricing approach. Oil-indexed pricing allowed buyers and sellers to access liquid oil futures markets to manage price risk through hedging.

For the first decades, LNG remained a small business. In 1971, six countries were importing LNG from three exporting countries. Even in 2000, there were just 11 importers and 12 exporters.

From around 2000, traditional business practices began to change

From around the turn of the millennium, the LNG business began to transition to being a global industry. The number of LNG buyers increased rapidly, facilitated by the advent of the FSRU in 2001, and growth in LNG trade accelerated (Figure 15.1). In 2017, 40 countries imported LNG from 19 exporters. As will be discussed in Section 3, FSRUs have allowed countries to begin importing LNG more quickly and at a lower cost than ever before.

Figure 15.1: LNG imports

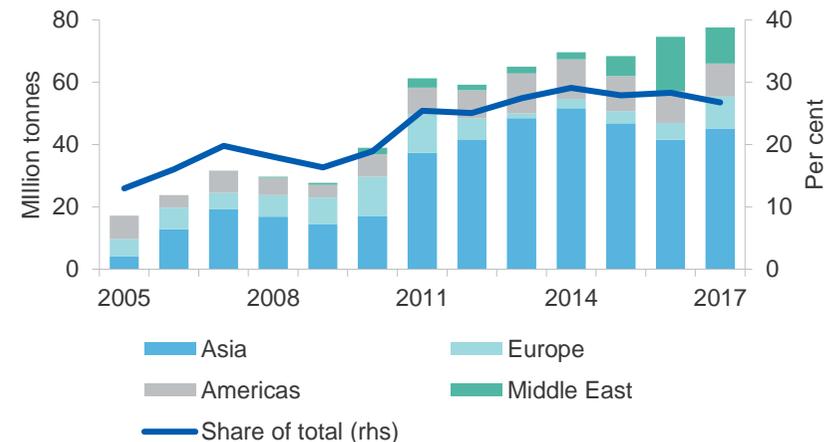


Source: IEA (2017) Natural Gas Information

The way LNG was traded also began to shift around 2000. The point-to-point business model started to fade and LNG ‘portfolio players’ emerged. These ‘portfolio players’ both produced LNG and/or purchased it from different regions, supplying buyers from their global portfolio, rather than from a specific LNG project.

From the mid-2000s, spot and short-term trade began to increase, as LNG from the Atlantic Basin was sold into Asia under trading arrangements other than long-term contracts. As Figure 15.2 shows, between 2005 and 2011, spot and short-term trade in Asia — defined as transactions under contracts of 4 years or less — increased nine-fold. By 2011, spot and short-term transactions accounted for 25 per cent of global LNG trade.

Figure 15.2: Spot and short-term LNG trade



Notes: Spot and short-term trade is defined as transactions under contracts of up to 4 years. Source: GIIGNL (2004–2017) Annual Report

Growing spot and short-term trade was driven by a combination of unexpected increases in Asian demand and a shortfall in supplies from some producers in the Pacific Basin. The unexpected increase in demand was in large part due to the Fukushima nuclear disaster in Japan in 2011, which resulted in Japan increasing LNG imports to fill the gap left by the closure of its fleet of nuclear power stations.

With the growth of spot and short-term markets in Asia, pricing arrangements in the region became more diverse. The price of spot LNG cargoes — where LNG is purchased for delivery within 4–12 weeks — was

based on the supply-demand dynamics for LNG, rather than on oil prices. Short-term contracts were often based on a hub price, such as Henry Hub in the United States or the National Balancing Point in Europe.

Meanwhile, non-price terms in contracts began to change. Recently, the Japanese Fair Trade Commission has said that new LNG contracts must not contain restrictions on the resale of cargoes, and called on sellers to revisit these practices in existing contracts. Box 15.1 discusses some of the efforts made by Asian buyers around LNG market reform.

Box 15.1: LNG market reform in Asia

Japan has been driving the agenda in terms of LNG market reform in Asia. In 2016, the Japanese Government released its *Strategy for LNG Market Development*. The Strategy's main proposition was that 'Japan should play a leading role in developing a flexible and liquid LNG market', with Japan serving as an LNG trading hub. The Strategy outlined three main goals in pursuit of this agenda: (1) to eliminate destination restrictions 'to the greatest extent possible'; (2) the 'creation of a proper price discovery mechanism' for LNG, noting that 'the pricing of LNG to crude oil prices is no longer necessarily justifiable'; (3) the development of open and sufficient infrastructure. The Strategy envisaged an expansion of LNG spot trade in Asia.

One factor motivating Japan is that some Japanese buyers are likely to be over-contracted for LNG over the next few years. One of the ways these buyers can manage their contractual positions is by entering the market as LNG sellers, but destination clauses — which prevent cargoes from being diverted before they arrive to Japan — complicate this approach.

Other major buyers — namely China and South Korea — may also face over-contracted positions over next few years. In March 2017, Japan's JERA — an equal joint venture of two major Japanese electric companies and the world's largest LNG buyer — executed a memorandum of understanding (MOU) with other large buyers in South Korea and China. The purpose of the MOU is to provide a platform for cooperation to achieve a more flexible LNG market. The Indian Government has also

argued that the removal of destination clauses and the oil-linked pricing approach would create a more flexible LNG market.

In short, major buyers in Asia are looking closely at new approaches to LNG trade, with implications for traditional business practices.

These trends have made LNG imports an option for Australia's east coast

The option of importing LNG into Australia's east coast gas market has been made possible by both the emergence of the FSRU business and changes in the way LNG is traded. While buyers may continue to need to sign long-term contracts to underpin the development of new LNG facilities and secure supply from these projects, buyers now also have access to a short-term market. This market offers a diverse set of contractual arrangements, with different pricing options and contractual lengths. While the benefits of portfolio players are sometimes contested, one view is that they have reduced the risk of supply disruptions from individual projects, and promoted the delivery of LNG to end-users from whichever source is the most economic.

15.3 Australia's east coast gas market and LNG import proposals

Prices in the east coast gas market have risen in recent years

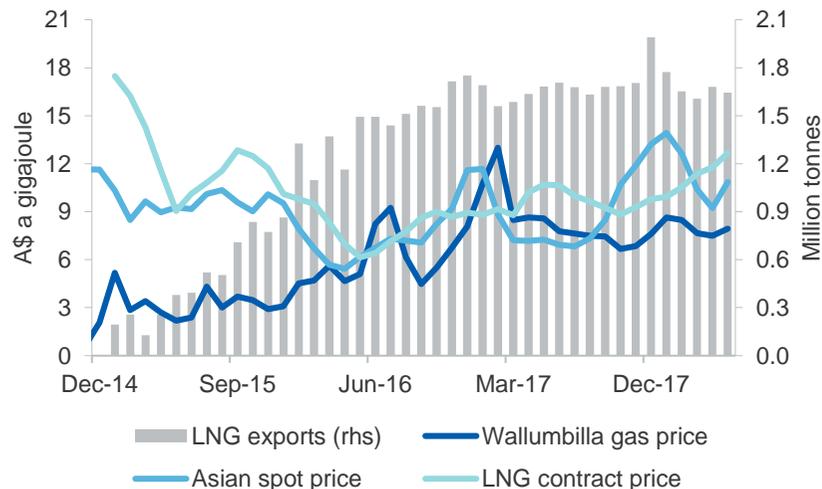
Australia has three gas markets that are not physically connected. The east coast gas market covers all states except Western Australia (which is covered by the western market) and the Northern Territory (northern market). The current east coast gas market can be thought of as consisting of two regions that are connected via pipeline — the North (i.e. Queensland) and the South (all other states). With the completion of the Northern Gas Pipeline (scheduled for the end of 2018), the Northern Territory will become part the east coast gas market.

Prices in the east coast gas market have risen over the past few years, as LNG exports from Queensland's three LNG projects have ramped up. In the 2000s — before the decisions to build the three LNG projects were made — wholesale gas prices were around \$3–4 a gigajoule. Between

mid-2016 and mid-2017, east coast prices escalated, at times climbing above international prices. Figure 15.3 shows how domestic wholesale spot prices at Wallumbilla (a Queensland gas hub) have risen over the past few years, spiking above international LNG prices at times during 2016–17. In February 2017, for example, the price of gas at Wallumbilla averaged \$13 a gigajoule, while LNG spot prices in North Asia averaged around \$9 a gigajoule.

By the end of 2017, east coast gas prices had moderated, but remained well above historical prices of \$3–4 a gigajoule. At the end of 2017, most offers for gas supply during 2018 and 2019 were in the \$8–10 a gigajoule range.

Figure 15.3: East coast exports, and LNG and domestic spot prices



Notes: Most gas in the east coast market is traded on confidential bilateral contracts, rather than on spot markets such as Wallumbilla. Nevertheless, the upward trend in domestic spot prices is indicative of domestic gas price rises over the past few years. The LNG contract price shown here is indicative only and is estimated as 14 per cent of the three-month lagged Japan Customs-cleared Crude (JCC) price plus shipping.
Source: AEMO (2018); Argus (2018); Gladstone Ports (2018)

Price rises in the past few years have been most pronounced in the southern part of the east coast gas market. Before LNG exports began in 2015, the southern gas market was supplied by the Cooper Basin. As LNG facilities ramped up production, some gas from the Cooper Basin was redirected for export, leading to a deterioration in competition in the southern market. This was particularly problematic for southern consumers, given that a large share of southern production was in the hands of a single supplier: the Esso-BHP Gippsland Basin Joint Venture (GBJV).

State government policies have constrained the development of new gas supply in the southern market. Victoria has a permanent ban on unconventional gas production and a moratorium on onshore conventional gas development until mid-2020. The New South Wales Government imposes heavy regulatory restrictions on unconventional gas development. These include additional review processes for Coal Seam Gas (CSG) projects on agricultural land that has been identified as highly productive, and exclusion zones on CSG development around existing and future residential areas.

LNG imports have become an option worth considering

A simple account of international trade would suggest that countries do not usually import and export the same product. If a country can produce a good for less than the world price, then it will export that good. That country will then meet its domestic requirements from its own production because this should be cheaper than importing the good at the world price.

There are a number of factors that have made LNG imports into the southern part of Australia’s east coast gas market worth considering. First, there is no single world price for LNG, and different pricing arrangements may mean that it is possible to export LNG at a higher price than the price for which LNG can be imported. The LNG projects on Australia’s east coast have long-term contracts with buyers in Asia, where LNG prices are linked to the price of Japan Customs-cleared Crude (JCC) oil. In contrast, prices in LNG spot and short-term markets usually depend on supply and demand for LNG. Where short-term contracts are oil-linked, these contract

prices are currently being signed at a discount to the oil-linked LNG prices on Queensland LNG contracts. This may mean that LNG could be imported into the southern gas market on a spot or short-term basis at a lower price than Queensland LNG is being sold on long-term oil-linked contracts.

On one view, LNG spot and short-term prices will decline over the next few years and remain low for some time. However, it is worth noting that LNG spot prices remain elevated at present, and faster than expected demand growth, especially in Asia, might mean that a period of overcapacity in LNG markets is short-lived. An increasingly popular view is that LNG markets will tighten in the early 2020s, rather than the mid-2020s as previously expected.

Another factor encouraging proponents of Australian LNG import terminals is a potential mismatch between supply and demand in the southern gas market. The ACCC expects gas production in the southern states (excluding production in the Cooper Basin) to fall short of southern gas demand by 25 per cent during 2018. The shortfall is, in large part, a result of declining output from older fields in the Bass Strait, which will not be offset by production from new fields (which contain higher impurity gas that requires additional processing). The southern states will need to rely on both gas from the Cooper Basin, and also from Queensland, to meet gas demand in 2018.

The southern states are likely to require ‘imports’ from the Cooper Basin, and potentially Queensland, for some time to come. Under the Neutral Scenario in the Australian Energy Market Operator’s (AEMO) *2018 Gas Statement of Opportunities* (GSOO) report, production from gas fields in the southern States, including the Cooper Basin, is mostly sufficient to meet southern demand. However, if Proved and Probable (2P) reserves and contingent resources in the South are not developed by the early 2020s, a greater volume of pipeline imports from Queensland would be required. AEMO’s March 2018 *Victorian Gas Planning Report* (VGPR) highlighted the risk that production in the Bass Strait could fall if new fields are not developed as expected. The VGPR noted Victorian gas production

is expected to fall from 435 petajoules in 2017 to 187 petajoules in 2022 if only current gas production developments or those that are currently committed in Victoria go ahead. A decline in offshore Victorian production would likely mean the South would require additional pipeline imports from Queensland.

According to the ACCC’s account of price formation in the east coast market, a production shortfall in the South means that southern producers can charge a price that approaches the southern ‘buyer’s alternative’ — the price of gas in Queensland plus the costs of transporting gas from the north to the south. The potential reliance of the southern gas market on northern production has opened up the possibility of LNG imports competing with pipeline imports from the North.

There are a number of reasons why LNG imports might be competitive with pipeline imports from the North. First, the cost of production in Queensland is relatively high. The vast majority of the gas produced in Queensland is CSG. CSG production requires drilling hundreds of new wells per year — something that conventional gas production does not require — which adds to the cost of extraction. Gas in many other parts of the world — be it US shale gas or conventional gas in Qatar or off Australia’s North West coast — has lower production costs. The ACCC estimates that the current cost of gas production from Queensland CSG fields is \$5–6 a gigajoule (US\$4–5 per MMBtu) at the wellhead. Contingent gas resources, likely needed to satisfy demand from the early 2020s, have higher production costs. AEMO estimates put the cost of production for contingent CSG resources in Queensland in the \$6–9 a gigajoule range (US\$5–7 per MMBtu).

Second, transporting gas via pipeline from Queensland to the southern market is relatively costly. The ACCC estimates that piping gas from the Wallumbilla gas hub in Queensland to the southern market costs \$1.85–\$2.45 a gigajoule, depending on the final destination. In contrast, it costs about \$1.50 a gigajoule to transport gas from Wallumbilla to Japan (about \$1 a gigajoule for liquefaction and \$0.50 a gigajoule for shipping). There

are also contractual and capacity limitations on pipelines that may limit the amount of gas that can flow from Queensland to the southern gas market.

There are two main types of LNG import terminals

There are two basic types of LNG import facilities: onshore land-based terminals and FSRUs. An FSRU is an LNG storage ship that has an on-board regasification plant capable of transforming LNG back into a gaseous state and then supplying it directly into the gas network. FSRUs can be new builds or converted LNG tankers.

FSRU's have lower capital costs, faster installation times and greater commercial flexibility compared to conventional onshore terminals. The cost of a new FSRU or an FSRU conversion is typically 50–60 per cent of the cost of an onshore gas terminal. FSRUs can also be put in place more quickly. A new build FSRU takes 2–3 years and a tanker conversion takes 18–24 months, whereas offshore import terminals take 3–5 years to construct. The other great advantage of FSRUs, however, is that they can also be leased, further reducing project costs and lead times. In the early days of the FSRU business, charter terms were generally 10 years, but charter terms as short as 5 years have been reported recently.

FSRUs typically have an import capacity of anywhere between 100 petajoules and 325 petajoules per annum.

There are four proposals for an LNG import terminal

There are four proposals for an LNG import terminal in Australia's east coast gas market (Table 15.1). All four proposals would involve importing LNG into the southern gas market and are awaiting a final investment decision (FID).

Australian Industrial Energy (AIE) — a joint venture between Andrew Forrest's Squadron Energy, Japan's Marubeni Corporation, and Japan's JERA — is considering an LNG import terminal at Port Kembla in New South Wales. The site is located near the existing New South Wales

pipeline network and gas could also be piped to Victoria via the Eastern Gas Pipeline.

AIE has flagged imports of up to 100 petajoules a year via an FSRU. An FID is targeted for the second half of 2018, with construction to begin in 2019, and first gas to be delivered to customers by early 2020. AIE expects the capital cost of the import terminal to be between \$200–300 million. AIE is also investigating the construction of a new 750 megawatt gas-fired power plant as part of the second stage of the project.

Secondly, AGL, an Australian energy retailer, is undertaking a feasibility study into an LNG import terminal at Crib Point, on Western Port Bay in Victoria. The site has an existing oil import jetty, at which an FSRU could be moored. AGL has engaged APA to investigate the construction of a 55–60 kilometre pipeline — with capacity of around 1 petajoule a day — from Crib Point to the existing Victorian gas pipeline network. A potential tie-in point with APA's Longford-Dandenong Pipeline at Pakenham has been identified.

Table 15.1: LNG import proposals

Project proponent	Location	Proposed start date
Australian Industrial Energy	Port Kembla, NSW	2020
AGL	Crib Point, VIC	2020/2021
ExxonMobil	Longford*, VIC	2022
Integrated Global Partners	Pelican Point, SA	n/a

Notes: *Longford has been reported as a potential site for ExxonMobil's LNG import terminal, although this has not been confirmed by the company. Source: Company websites (2018), Australian Financial Review (2018), The Australian (2018), APA (2018), The Sydney Morning Herald (2018).

AGL's LNG import terminal, with capacity of around 100 petajoules a year, would start operations in 2020 or 2021. AGL has estimated the costs of LNG import terminal infrastructure at around \$250 million. This does not

account for the annual leasing and operating costs of an FSRU. AGL expects to make an FID in financial year 2018–19.

Thirdly, ExxonMobil is considering building a Victorian LNG import plant, which could take advantage of existing gas infrastructure at the Longford gas plant. Imports would start around 2022 if the project, which is in the early stages of assessment, is approved.

A fourth proposal is the Outer Harbour project led by Melbourne-based management consultancy Integrated Global Partners. Mitsubishi has reportedly supported the project by financing a feasibility study. The project would see an FSRU moored at a new wharf to be built at Pelican Point near Adelaide.

15.4 Key issues around LNG imports

The commercial viability of LNG imports depends on several factors

The following section discusses a number of issues surrounding LNG imports. The section begins with a discussion of the different purchasing arrangements that could underpin LNG imports. It then examines two issues affecting the price for which imported gas might be delivered to customers, and thus the commercial viability of LNG imports. The first of these is the cost of the LNG itself, which in turn is affected by factors such as the cost of delivering US LNG to Asia, European hub prices and oil prices. The second is regasification costs, which depend on the capital costs of the project, the leasing costs of the FSRU and the volume of LNG imported.

A variety of purchasing arrangements could underpin LNG imports

There are a variety of contractual arrangements that could underpin LNG imports into Australia's east coast gas market. LNG imports could also be purchased on a spot basis. However, the lack of a liquid LNG futures market in Asia means market participants would be unable to eliminate the risk of higher than expected spot prices.

LNG imports could also be purchased on short-term contracts, which are commonly less than 4 years. AIE has stated contracts could be slightly longer, at 5–7 years.

Contracts for LNG imports could be linked to oil prices. Alternatively, LNG imports could also be linked to another reference price, such as the Henry Hub price in the United States. The advantage of oil-linked and Henry Hub pricing is that LNG project proponents would have access to large futures markets, which would allow market participants to lock in LNG prices.

The cost of US LNG could be critical to LNG import proposals

The main cost of importing LNG is the price of the LNG itself. The price of imported LNG will depend on the interaction of both demand-side and supply-side factors in spot and short-term contract markets in Asia. Australian LNG import prices are expected to be broadly comparable to those paid by Asian consumers.

A key supply-side factor encouraging the proponents of LNG import terminals on Australia's east coast is the expansion in global LNG export capacity that is underway. This expansion in global liquefaction capacity, led by the United States, could usher in a period of low LNG spot and short-term prices, although the sustainability of low prices is a key question.

With the United States emerging as a major source of new supply, the cost of delivering US LNG to Asia could have an impact on prices in the region. While pricing arrangements vary across US LNG contracts, the rule of thumb is that the cost of US LNG can be broken into four components: the Henry Hub gas price, a 15 per cent surcharge on the Henry Hub price to cover the cost of liquefaction and pipeline costs from Henry Hub to liquefaction plants, a fixed capacity charge (also known as a 'tolling fee') that covers the capital costs of the liquefaction plant, and transport costs from the US to Asia.

Tables 15.2 and 15.3 (on the next page) provide illustrative calculations for the cost of delivering US LNG to Asia via the Panama Canal — the lowest cost shipping route to Asia from LNG plants on the US Gulf Coast. Henry Hub prices are currently around US\$3.0/MMbtu (\$3.80 a gigajoule) and shipping costs are around US\$1.90/MMbtu (\$2.40 a gigajoule).

Table 15.2: Illustrative cost of delivering US LNG to Asia, US\$/MMbtu

Component	Low	Mid	High
Henry Hub gas	2.5	3.0	3.5
15% surcharge	0.4	0.5	0.5
Transport to Asia	1.2	1.7	2.2
Variable cost	4.1	5.2	6.3
Fixed capacity fee	2.3	2.9	3.5
Full cost	6.3	8.0	9.8

Table 15.3: Illustrative cost of delivering US LNG to Asia, A\$/GJ

Component	Low	Mid	High
Henry Hub gas	3.2	3.8	4.4
15% surcharge	0.5	0.6	0.7
Transport to Asia	1.5	2.1	2.8
Variable cost	5.1	6.5	7.9
Fixed capacity fee	2.8	3.6	4.4
Full cost	8.0	10.1	12.3

Notes: An exchange rate of A\$1.00 = US\$0.75 has been used. Transport costs are for return shipping from the US Gulf Coast to Tokyo via the Panama Canal. The low case represents the lowest average monthly shipping cost since October 2016 (first available data), while the high case is the highest average monthly cost on record. Historical data suggests an alternative shipping route would add US\$0.30–US\$0.80 to the cost of shipping. Fixed capacity charges reportedly range from US\$2.35/MMbtu to US\$3.50/MMbtu.

Source: Argus (2018); Bordoff and Losz (2016)

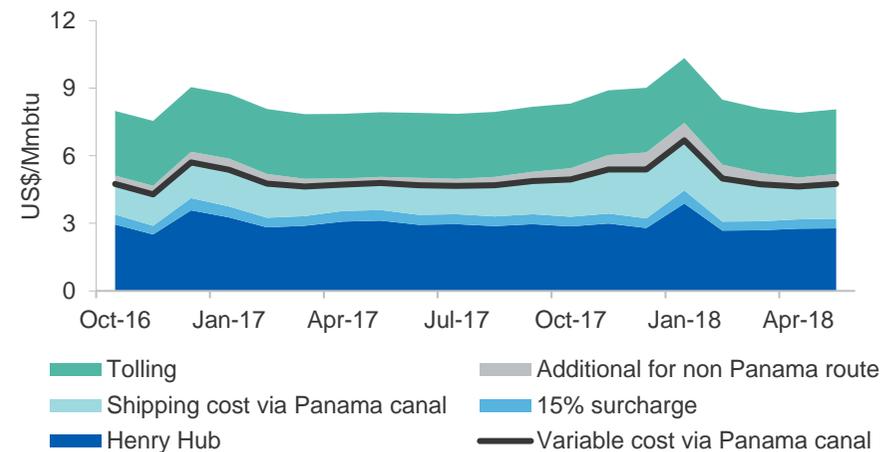
One question for Australian buyers looking to sign up for short-term contracts with US exporters is the cost of the fixed capacity fee in a new contract. Table 15.3 suggests a fixed capacity fee comparable to that paid by Asian buyers (in the contracts that underwrote US LNG projects) would be an additional \$2.80–\$4.40 a gigajoule. However, given US exporters have already recouped their capital costs via the fixed capacity fee in their

contracts with Asian buyers, US exporters may be willing to reduce fixed capacity charges in new contracts.

Figure 15.4 shows how the cost components of US LNG have changed since October 2016. Henry Hub prices are expected to remain around US\$3.0/MMbtu over the next few years.

The capacity of the Panama Canal (the fastest route from the US' east coast terminals to Asia) to accommodate growing LNG shipments could potentially limit growth in US exports to the region. Research from the Oxford Institute for Energy Studies suggests that the Panama Canal, which has a capacity of 28 million tonnes per annum, could become a bottleneck in the early 2020s.

Figure 15.4: Cost components of US LNG exports



Source: Bloomberg (2018); Argus (2018); Bordoff and Losz (2016)

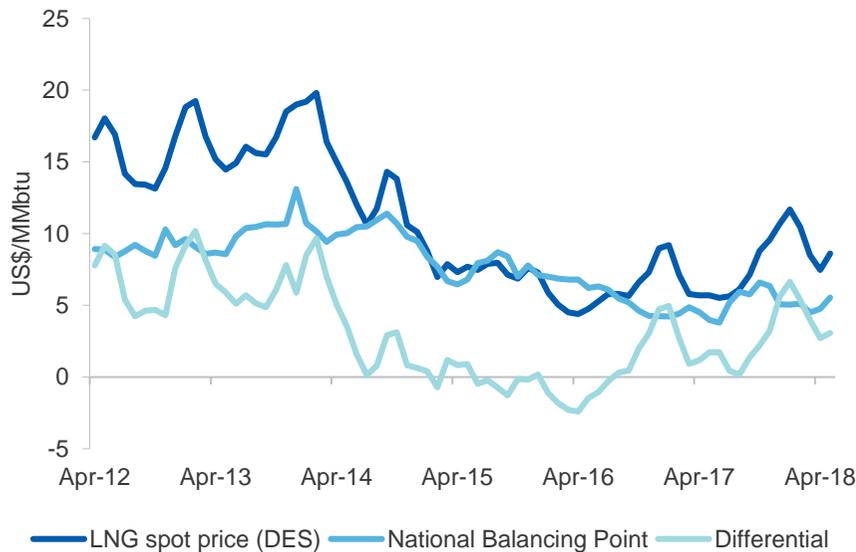
European hub and oil prices could also influence LNG import costs

There are other factors influencing Asian LNG spot and short-term prices, especially if overcapacity in world LNG markets does not emerge. Over the past few years, Asian LNG spot and short-term prices have been broadly correlated with European hub prices. LNG producers in the

Atlantic Basin have the option of selling cargoes into Europe, which has plentiful gas storage capacity and can act as the 'destination of last resort'. This has meant Asian buyers have needed to pay European hub prices plus the additional costs of transporting gas to Asia, in order to secure Atlantic Basin cargoes.

Figure 15.5 shows that North East Asian LNG spot prices have tracked closely with prices at Europe's National Balancing Point. Between 2012 (earliest data available) and 2014, the differential between European hub and Asian spot prices widened. The 2011 Fukushima event, which saw the shutdown of Japan's nuclear fleet and a concurrent surge in demand for LNG in Asia, pushed up LNG prices in Asia relative to prices in other parts of the world; a phenomenon which became known as the "Asian premium".

Figure 15.5: North East Asian LNG spot and European hub prices



Notes: DES stands for Delivered Ex Ship. DES LNG includes the cost of shipping and insurance.

Source: Argus (2018); Bloomberg (2018)

As LNG markets became better supplied from 2014, the differential between European hub and Asian LNG spot prices has narrowed, with the exception of a number of price spikes during the northern winter, when Asian LNG demand has surged.

There has also been a historical relationship between LNG spot prices and oil-linked contract prices, as Figure 15.6 shows. Since April 2012, the monthly differential has not typically exceeded US\$5/MMbtu, averaging just US\$2.0/MMbtu. Both demand and supply side factors explain this correlation. LNG buyers have some flexibility on long-term oil-linked contracts, allowing them to increase/decrease long-term contract purchases depending on the relative attractiveness of the LNG spot market. Higher contract prices increase demand for LNG spot cargoes, pushing up spot prices. Low contract prices, on the other hand, make contracted volumes more attractive, pushing down demand for spot cargoes and thus spot prices. There is also some substitution between oil and gas in end-use sectors, which may contribute to price convergence.

Figure 15.6: Asian LNG spot versus long-term contract price, DES



Notes: the contract price shown here is indicative only and is estimated as 14 per cent of the three-month lagged JCC price plus shipping. DES stands for Delivered Ex Ship. DES LNG includes the cost of shipping and insurance.

Source: Argus (2018); Bloomberg (2018)

Supply-side factors also help to explain the historical relationship between LNG spot and oil-linked contract prices. Oil and gas are co-produced, meaning that increased production for one commodity sees production of the other rise too. The extent to which LNG spot and short-term prices might break away from oil-linked contract prices as LNG supply capacity grows over the next few years remains to be seen.

Regasification costs will also be important

Aside from the cost of the LNG itself, regasification — converting LNG back into gas — is the other major cost associated with importing the liquid fuel. Regasification costs depend on both the capital costs of the LNG import terminal and the leasing and operating costs of the FSRU. Regasification costs per unit largely depend on the volume of gas imported through the FSRU, i.e. on the level of throughput. The larger the volume of LNG imported, the lower regasification costs are on a per unit basis.

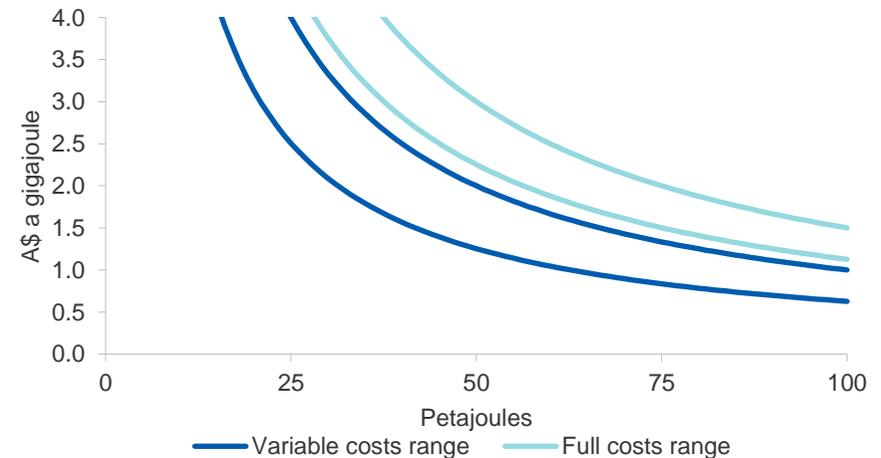
Table 15.4 and Figure 15.7 provide an illustrative example of the costs per gigajoule of regasification for an FSRU importing up to 100 petajoules per annum. Variable costs cover only the costs of leasing and operating the FSRU, while full costs include the capital costs of the import terminal. The costs of leasing and operating an FSRU are usually US\$47–75 million a year (or \$63–100 million at an AUD–USD \$0.75 exchange rate) — and this range has been used to inform the low, mid and high cases. The capital costs have been assumed to be \$250 million.

Based on this calculation, variable regasification costs would be \$0.80–\$1.30 if 75 petajoules of LNG were imported per year. If capital costs were spread over five years, that would add around \$0.70 cents a gigajoule. This would bring the overall costs of regasification of an LNG import terminal importing 75 petajoules of gas for five years, to \$1.50–\$2.00 a gigajoule. If an FSRU was to operate for longer than five years, the capital costs would be reduced.

Table 15.4: Illustrative regasification costs per gigajoule as a function of throughput, A\$ a gigajoule

Throughput (Petajoules)	Low case (A\$/GJ)	Mid case (A\$/GJ)	High case (A\$/GJ)
Variable costs			
100	0.6	0.8	1.0
75	0.8	1.1	1.3
50	1.3	1.6	2.0
Full costs			
100	1.1	1.3	1.5
75	1.5	1.8	2.0
50	2.3	2.6	3.0

Figure 15.7: Illustrative regasification costs per gigajoule as a function of throughput



Notes: Full costs include the leasing and operating costs of the FSRU, and the capital costs of the LNG import terminal. Variable costs cover only the leasing and operating costs of the FSRU. The calculation is based on: FSRU leasing and operating costs of \$63 million, \$81 million and \$100 million per annum in the low, mid and high cases, respectively; capital costs of \$250 million, LNG being imported for a period of five years.

Source: Department of Industry, Innovation and Science (2018)

Lowering regasification costs will require demand aggregation

'Demand aggregation' — bringing together a number of buyers willing to purchase imported LNG — will be critical to achieving a high capacity utilisation for an LNG import terminal, and thus to underpinning its commercial viability. Despite only a small-scale FSRU being proposed on the east coast, it is unlikely that a single end-user would purchase sufficient amounts of gas to underwrite an LNG import terminal. The capacity of a small-scale FSRU is around 100 petajoules per annum. Small industrial customers in the east coast gas market consume just 0.1–1 petajoules per annum. Large industrial customers are those who consume over 1 petajoule of gas per annum. The annual gas consumption of Incitec Pivot, a fertiliser and explosives manufacturer (and one of the largest industrial gas customers on the east coast), is 31–33 petajoules. Customers purchasing imported gas will also have to balance contracts with LNG import project proponents with their existing gas supply portfolio.

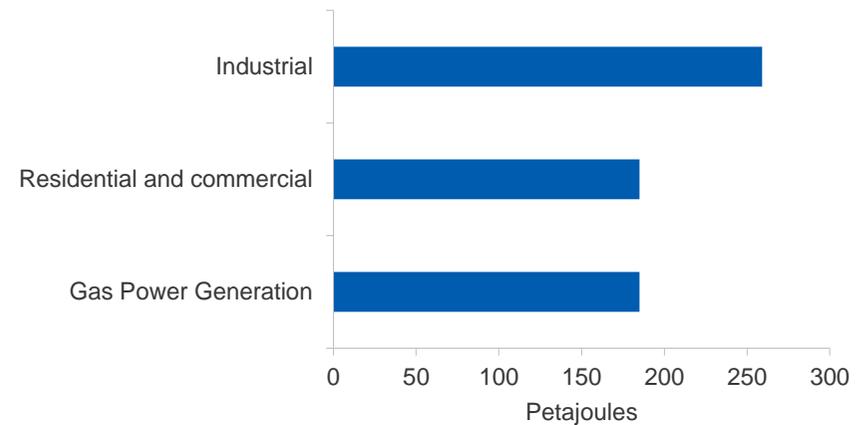
An LNG import terminal with capacity of 100 petajoules per annum would service a significant share of east coast domestic gas demand. One hundred petajoules of gas equals 16 per cent of total domestic gas consumption on the east coast in 2017 (629 petajoules) and 21 per cent of southern gas consumption in 2017 (474 petajoules).

There are a number of possible customers for east coast LNG imports. Industrials are one group of potential customers. The industrial sector is the largest gas consuming sector in the east coast gas market, accounting for slightly less than half of total domestic consumption. Large industrial customers require long-term supply agreements to lend stability to their business operations, and seem a likely candidate for LNG imports.

A second group of customers is in the residential and commercial sector. An energy retailer would need to agree to purchase LNG if imported gas is to be consumed in this sector.

The third set of customers are gas-power generators (GPGs). Whether many GPG operators will be willing to sign up to contracts to underpin LNG imports remains to be seen.

Figure 15.8: Gas consumption in 2017 in the east coast market



Source: AEMO (2018)

As gas prices have risen over the past few years, many GPGs have switched to a peaking strategy in the National Electricity Market (NEM); a strategy which involves only generating when electricity prices are high, rather than trying to compete for intermediate demand. GPG operators who adopt a peaking role may only require gas at particular times and in small quantities. For many GPGs, contracts for gas supply for several years may not be compatible with their peaking strategy in the NEM.

AGL has an existing residential and industrial customer base, as well as gas-power generation assets. In 2017–18, AGL's gas sales totalled 231 petajoules. There is also gas storage at the Iona facility in Victoria, with capacity of 26 petajoules, where imported gas could potentially be stored during periods of low consumption.

AIE's proposal potentially involves building a 750 megawatt combined cycle gas-fired power station. Such a power station, operating at an 80 per cent load factor, and with an efficiency of 50–55 per cent, would require 40–43 petajoules of gas a year. A new gas-fired power station would help to underwrite the demand required to make LNG imports economic, but

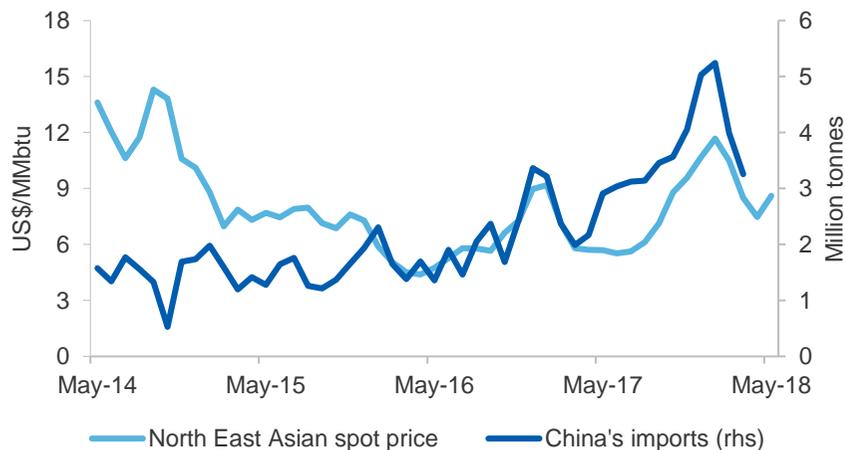
whether a new gas-fired power plant is commercially viable is contingent on developments in the NEM.

An additional challenge in sustaining a high and steady level of throughput at an FSRU is the seasonal nature of gas demand, especially in the southern market. Gas demand in southern Australia is highly cyclical, with low demand in summer and high demand in winter. Current gas demand in southern markets across all sectors ranges between 600–900 terajoules per day in summer to 1200–1500 terajoules per day during winter. Having an FSRU off-line for half of the year is unlikely to be economic.

The timing of seasonal demand in Australia could be an advantage

A final issue to consider is seasonality in LNG spot prices. Asian LNG spot prices have spiked over the past two winters, as shown in Figure 15.9. The most recent spike was, in large part, driven by a sharp rise in China’s LNG imports. Australia’s peak domestic demand period is during the northern hemisphere summer. This could be an advantage from the perspective of importing LNG, allowing spot LNG imports during periods of lower prices.

Figure 15.9: North East Asian spot price and China’s LNG imports



Source: Argus (2018)

15.5 Conclusion

The fact that Australia may one day both export and import LNG from Australia’s east coast seems paradoxical. However, while there are challenges to LNG imports into Australia’s east coast gas market, there are also reasons to think that proposals for an import terminal may go ahead. The potential for a mismatch between demand and supply in the southern gas market, the high cost of Queensland gas and transportation costs from north to south, and a subdued outlook for Asian LNG prices appears to have made the LNG import option worth considering.

If LNG imports are economically viable, they would have important implications for Australia’s east coast gas market. The southern market could well face a situation in coming years where southern producers are able to charge a price that approaches the so-called southern ‘buyer’s alternative’ — the price of gas in Queensland plus the costs of transporting gas from north to south. LNG imports can be viewed as expanding the options for buyers in the southern gas market, and potentially lowering the southern ‘buyer’s alternative’. In this way, the price of LNG imports may act to cap the price of gas in the southern gas market. The overall impact on southern gas prices will depend on the price at which LNG imports can be delivered to southern consumers. This price will, in turn, be shaped by developments in Asian LNG spot and short-term markets.