Gas
Resources and Energy Quarterly March 2018

LNG is natural gas cooled to −162°C

2nd largest LNG exporter in the world

52 million tonnes of LNG exported in 2016–17

41% rise from 2015–16 export volumes

Combined nameplate capacity of Australia’s 10 LNG projects is 88 million tonnes per annum

Most Australian LNG is sold on oil-linked contracts

Australia’s LNG key export destinations, 2016–17

48% Japan
29% China
11% South Korea
7% Singapore
3% India
3% Rest of the world

Global share of LNG exports in 2016

30% Qatar
16% Australia
10% Malaysia
7% Nigeria
6% Indonesia
32% Rest of the world

Global share of LNG imports in 2016

34% Japan
13% South Korea
9% China
7% India
5% Taiwan
31% Rest of the world
7.1 Summary

- The real value of Australia’s LNG exports is forecast to increase from $23 billion in 2016–17 to $39 billion in 2022–23, driven by higher export volumes and, to a lesser extent, higher prices. LNG is forecast to overtake metallurgical coal as Australia’s second largest resource and energy export in 2018–19.
- The completion of the final three Australian LNG projects under construction will underpin strong growth in export volumes and bring total export capacity to 88 million tonnes.
- LNG contract prices — at which most Australian LNG is sold — are projected to increase gradually in line with oil prices.
- Australian LNG projects are likely to face increasing competition. Global LNG markets look set to move into a period of overcapacity, starting in the second half of 2018 and lasting through to 2020. However, slippages in project completions have the potential to delay overcapacity.

7.2 Prices

Asian LNG prices recovered in 2017

Gas prices and gas pricing mechanisms vary from region to region. Prices for LNG delivered into North Asia increased in 2017, driven by a gradual recovery in oil prices. Oil-linked pricing has been the dominant pricing mechanism in Asia since Japan began importing LNG in the late 1960s as a substitute for oil in power generation. The average price of LNG (Delivered Ex Ship) imported by Japan — the world’s largest LNG buyer — was $9.80 a gigajoule in 2017 (US$8.0 per MMbtu), up from $8.70 a gigajoule in 2016 (US$6.80 per MMbtu).

Asian LNG spot prices also recovered in 2017. Prices (Delivered Ex Ship) averaged $9.00 a gigajoule (US$7.20 per MMbtu), up from $7.40 a gigajoule in 2016 (US$5.80 per MMbtu). Prices rose sharply towards the end of the year (Figure 7.1), driven by strong winter buying by major importers in Asia (particularly China), but have subsequently declined to around $10.50 in March 2018 (US$8.60 per MMbtu).

LNG contract prices to increase, but LNG spot prices to fall

Oil-linked LNG contract prices in North Asia are projected to rise gradually over the outlook period. The real Japan Customs-cleared Crude (JCC) oil price, to which Asian LNG contract prices are often linked, is projected to increase from US$55 a barrel in 2017 to US$60 a barrel in 2023.

LNG spot prices in Asia are expected to decline in the short term. Asian LNG spot prices (Delivered Ex Ship, real 2018 dollar terms) are forecast to fall to an average $6.60 a gigajoule in 2019 (US$5.60 per MMbtu), as additions to global supply capacity outstrip growth in LNG demand over the next few years. LNG spot prices are then projected to gradually recover from 2020 as supply growth slows, reaching an average $9.40 a gigajoule in 2023 (US$7.90 per MMbtu).

Figure 7.1: Gas and LNG prices, monthly

Notes: Henry Hub is the US domestic gas reference price. National Balancing Point is the most liquid gas trading hub in Europe.
Source: Argus (2018); Bloomberg (2018)

With the United States emerging as a major source of new supply, US LNG exports are expected to add to downward pressure on Asian LNG spot prices over the next few years. The cost of delivering US LNG to Asia will be determined by the price for which US LNG exporters can purchase
domestic gas for export, plus the cost of liquefaction and transportation to Asia. If current Henry Hub prices persist, and if tolling fees (fixed charges paid by LNG buyers that cover the capital costs of US LNG plants) are treated as a sunk cost, this could potentially be as little as US$5.00 per MMbtu ($6.30 a gigajoule). However, 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.

**Box 7.1: Price developments in the eastern gas market**

The majority of gas in Australia’s eastern market — which excludes the Northern Territory — is traded on bilateral contracts. Prices on recently executed contracts for gas supply in 2018 in Australia’s eastern gas market are around current netbacks from oil-linked LNG contract prices; that is, around LNG contract prices less the costs of liquefying and transporting gas from Australia to international customers.

According to the ACCC December 2017 Gas Inquiry, the average wholesale gas price for supply in 2018 on a new gas supply agreement is A$8.45/GJ in Queensland and A$9.01/GJ in the southern part of the eastern gas market. In early 2018, LNG netbacks from oil-linked contract prices were in the $8-9 a gigajoule range at Wallumbilla, Queensland.

Domestic wholesale spot prices have only increased modestly as Asian LNG spot prices have spiked, as Figure 7.2 shows. The December 2017 *Resources and Energy Quarterly* identified a number of reasons for this, including rigidities in organising sales of spot LNG, a lack of liquidity in domestic spot markets, and other influences on domestic spot prices.

Expectations of future international LNG prices are expected to shape domestic contract price negotiations as buyers look to recontract for new supply. Domestic gas prices in Australia’s eastern gas market may become increasingly integrated with global LNG prices if an LNG import terminal is established in the southern part of the market. AGL is considering an LNG import terminal in Victoria, starting operations in 2020 or 2021, while Australian Industry Energy (AIE) is considering one in New South Wales.

**Figure 7.2: Netbacks from international LNG prices and the Wallumbilla gas price, monthly**

![Graph showing netbacks from international LNG prices and the Wallumbilla gas price, monthly](image)

Notes: an LNG netback is an international LNG price minus the costs of transport, liquefaction and transmission to the destination in question. The netbacks shown here are calculated using historical shipping price data and assumptions on liquefaction and transmission costs. The spot price netback uses the Argus North East Asian spot price. The FOB price of LNG on Gladstone oil-linked contracts is estimated at 14 per cent of the three-month lagged Japan Customs-cleared Crude (JCC) oil price.

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

### 7.3 World trade

World LNG imports are projected to increase from 250 million tonnes in 2016 to 378 million tonnes in 2023. Emerging Asia — led by China — and Europe are expected to drive demand growth. Prospects for growth in the imports of Japan and South Korea are more limited.

Despite robust growth in demand, the expansion in global LNG supply capacity is expected to outpace LNG demand over the next few years. Overcapacity in global LNG markets is expected to set in sometime in 2018 and last through to 2020 (Figure 1.3). The expansion in global liquefaction capacity will be concentrated in the United States, Australia and Russia.
From early next decade, however, the market is expected to begin rebalancing, as growth in global liquefaction capacity slows in the second half of the outlook period. There are few new LNG projects in the investment pipeline, and LNG projects typically have lead times of five years or more between final investment decisions (FIDs) and completion.

**Figure 7.3: Global liquefaction capacity and LNG demand**

[Graph showing global liquefaction capacity and LNG demand]

Notes: global liquefaction capacity is nameplate capacity.
Source: Nexant (2017); Department of Industry, Innovation and Science (2018)

### 7.4 World imports

**Nuclear restarts to weigh on Japan’s LNG imports**

The LNG imports of Japan, the world’s largest buyer, are projected to fall from 86 million tonnes in 2017 to 76 million tonnes in 2023. Gas consumption in both the residential and industrial sectors is expected to remain relatively stable over the outlook period. At the same time, LNG is expected to face increasing competition in the power generation sector, which accounts for around two-thirds of Japan’s gas consumption.

The Fukushima nuclear disaster in 2011 resulted in the closure of Japan’s fleet of nuclear reactors. At the time of writing, five of Japan’s fleet of 42 nuclear reactors, with a combined capacity of 4.4 gigawatts, had recommenced operations. Four more reactors (combined capacity 4.7 gigawatts) had received final approval to restart. A further 21 reactors have applications in front of the Nuclear Regulation Authority for restart — the administrative body charged with ensuring the safety of nuclear plants.

The timing and scale of nuclear restarts remains a key uncertainty affecting the outlook for gas consumption in Japan. To date, the pace of nuclear restarts has been slow, with nuclear energy continuing to face public opposition. There remain significant risks of delays and slippages in nuclear restarts.

Gas is also expected to face increasing competition in power generation from renewable energy sources. Between 2010 and 2016, renewable generation in Japan increased from 10 terrawatt hours to 50 terrawatt hours, with most of the increase led by solar and wind power.

**Figure 7.4: LNG import forecasts**

[Graph showing LNG import forecasts for different countries]

Notes: 2017 is an estimate.
Source: Nexant (2017); Department of Industry, Innovation and Science (2018)
Modest growth projected for South Korea’s imports

South Korea’s LNG imports are projected to increase slightly over the outlook period, rising from 36 million tonnes in 2017 to 38 million tonnes in 2023. Gas consumption in the residential and industrial sectors is expected to remain relatively flat. However, there is potential for growth in gas use in power generation, which accounts for around half of South Korea’s gas consumption.

South Korea’s long-term plan is to increase the share of gas in the energy mix from 15 per cent in 2016 to around 19 per cent by 2030. Gas-fired generation capacity will increase by around a third, while no new coal or nuclear plants (other than those under development) will be approved.

Over the outlook period (to 2023), several recent announcements by the South Korean government should support the use of LNG in power generation. From 2018, South Korea will suspend operations at eight old coal-fired power stations between March and June each year in order to reduce air pollution. These eight coal-fired power stations, plus a further two, will be permanently closed by mid-2022. The Government also intends to close the aged Wolsong 1 nuclear reactor, with reports this could occur as early as 2018.

If coal-fired and nuclear generation capacity is reduced, increased LNG imports may be required. While the medium term outlook is for a modest increase in South Korea’s imports, South Korea’s LNG imports are forecast to decline slightly in 2018. South Korea experienced unexpected nuclear outages over 2017, and the return to operation of nuclear reactors over 2018 is expected to weigh on LNG imports in the short term.

China will make the single largest contribution to growth in LNG demand

China’s LNG imports increased rapidly in 2017, driven by government policies designed to address air pollution by encouraging gas use in place of coal. The Chinese government is aiming to increase the share of gas in the energy mix from 5.3 percent in 2015 to 8.3-10 per cent in 2020. Chinese gas consumption is projected to reach the lower end of this target in 2020, before climbing to 357 billion cubic metres in 2023.

LNG is expected to play an important role in servicing rising gas demand. China’s LNG imports are forecast to increase from 37 million tonnes (50 billion cubic metres) in 2017 to 57 million tonnes in 2020, before declining to 50 million tonnes (68 billion cubic metres) in 2023.

Figure 7.5: China’s gas consumption by source, 2016–2023

A key factor affecting China’s LNG demand will be the extent of competition from domestic gas production and gas imported through pipelines. China’s pipeline imports are expected to remain relatively stable over the first half of the outlook period. From the early 2020s, however, LNG will likely face stiffer competition from pipeline imports. China is expected to begin importing gas from Russia via the Power of Siberia pipeline around this time, starting at 5 billion cubic metres in the first year of operation and reaching 38 billion cubic metres in the sixth year.

China’s domestic production is expected to grow steadily over the outlook period. China is reportedly targeting natural gas production of 220 billion cubic metres in 2020, up from 137 billion cubic metres in 2016, including an increase in shale gas production from 4.5 billion cubic metres in 2015 to 30 billion cubic metres in 2020. China’s gas production is not expected to reach this target during the outlook period.
Other emerging Asian economies to also drive demand growth

Other economies in emerging Asia are expected to make a large contribution to growth in global LNG imports, including India, Pakistan, Bangladesh, Indonesia, Thailand and Singapore. Growth will be underpinned by low LNG spot and short-term contract prices and the availability of floating storage and regasification unit (FSRU) technology. FSRU technology can be installed relatively cheaply and quickly compared to a conventional onshore import terminal, opening up the option for countries to import small volumes of LNG.

India’s LNG imports are projected to grow substantially, climbing from 18 million tonnes in 2017 to 37 million tonnes in 2023. The Indian Government is aiming to increase the share of gas in the energy mix from 6.5 per cent at present to 15 per cent as soon as 2022, according to recent statements. India’s domestic production is not expected to keep pace with the country’s future gas needs, and LNG is expected to play an important role in meeting rising demand. India currently has four LNG import facilities, and the Indian Government has announced plans to build 11 new import terminals on India’s east coast over the next seven years. The extent of India’s LNG requirements will partly depend on progress on the Iran-Pakistan-India and Turkmenistan-Afghanistan-Pakistan-India pipelines.

Europe’s LNG imports are set to increase

Despite a relatively subdued demand outlook for gas consumption, European LNG imports are projected to increase to 68 million tonnes in 2023, up from an estimated 41 million tonnes in 2017. Europe’s pipeline imports are expected to remain relatively stable over the outlook period, while European gas production is projected to fall (particularly in the Netherlands), creating room for LNG imports to grow.

While Europe is not a large market for Australian LNG, the outlook for European gas demand is still important for Australian producers. If LNG demand in Europe does not grow as strongly as projected, Qatari and US LNG may be displaced, potentially bringing increased competition to the Asia-Pacific.

7.5 World exports

A major expansion of world LNG supply capacity is underway

The next few years are expected to see a major expansion in global LNG supply capacity. Around half of all new capacity will come from the United States. By the end of 2019, all six LNG projects in the United States are expected to have commenced operations, bringing the combined nameplate capacity of US LNG projects to 67 million tonnes.

Major new capacity additions are also expected in Australia (discussed below) and Russia. LNG capacity is Russia is expected to expand over the next few years as the Yamal LNG project (nameplate capacity of 16.5 million tonnes) comes online. The Yamal project shipped the first cargo from the first of its three LNG trains in March 2018.

Qatar’s LNG exports are projected to remain largely unchanged

Qatar is the world’s largest LNG exporter. Since 2011, Qatar’s exports have ranged from 72-77 million tonnes per annum, and they are projected to remain in this range over the outlook period.
Qatar’s plans to increase LNG production capacity by 30 per cent to 100 million tonnes are not expected to have a significant impact on its LNG exports over the next five years. The expansion, announced in mid-2017, is expected to take 5-7 years to complete. Growth in LNG exports will be supported by new gas production from Qatar’s North Field. Qatar lifted its self-imposed moratorium on new gas development at its North Field in April 2017.

7.6 Australia

LNG export earnings to increase, largely driven by higher export volumes

Australia’s LNG export earnings are forecast to increase from $23 billion in 2016–17 to $39 billion in 2022–23 (2017–18 dollar terms). As Figure 7.7 shows, rising export values will be driven by higher export volumes (especially over the short term) and, to a lesser extent, higher prices.

Australia’s LNG export volumes are forecast to reach 79 million tonnes in 2022–23, up from 52 million tonnes in 2016–17. Higher export volumes will be driven by the completion of the three remaining LNG projects under construction — Wheatstone, Ichthys and Prelude. The completion of these three projects will bring the combined nameplate capacity of Australia’s LNG projects to 88 million tonnes.

Chevron’s Wheatstone project is likely to be the first of the three projects completed. Train 1 at Wheatstone has already begun production while train 2 is due to come online in the June quarter 2018. Shell has indicated that the Prelude Floating LNG project will be completed between May and August 2018. First gas production at Inpex’s two train Ichthys project is expected to start in April or May 2018.

Additional export capacity could be added later in the outlook period. Woodside concluded feasibility studies last year for a capacity expansion at the Pluto project of between 0.7 and 3.3 million tonnes per annum. The first expansion option — debottlenecking — would add just under one million tonnes of capacity. The second — an off-the-shelf train that would plug-in to the existing infrastructure — would add 1 to 1.5 million tonnes.

A larger expansion would see gas from the Scarborough gas field piped through the Pluto LNG plant.

Higher Australian LNG prices to play a part in lifting export earnings

The price of Australian LNG (FOB) is projected to edge up from $8.30 a gigajoule in 2016–17 to average $9.30 a gigajoule in 2022–23 (Figure 7.8). Higher export prices will be driven by rising oil-linked contract prices. Most Australian LNG is sold into Asia on contracts linked to the price of Japanese Customs-cleared Crude (JCC) oil by a time lag of around three months. However, low LNG spot prices will play some role in constraining the average export price realised over the next few years, as Australian exporters increase their share of sales at spot prices.
Notes: Export prices are export unit values. Source: ABS (2018); Department of Industry, Innovation and Science (2018)

Australia is not immune from supply-side competition
While Australian LNG exports are projected to increase, the capacity utilisation of Australian LNG export projects is expected to edge down as supply-side competition increases over the next few years. The extent to which capacity utilisation declines will depend on the flexibility that buyers have in their contractual arrangements with Australian exporters. LNG contracts often include clauses which allow buyers to reduce purchases to minimum ‘take-or-pay’ levels.

The flexibility with which buyers can reduce purchases on Australian contracts is likely to be important if oil-linked contract prices and spot prices diverge, encouraging buyers to reduce imports on contracts to minimum levels and to boost purchases on the spot market. The flexibility in Australian contracts is also likely to be important at times when buyers are over-contracted and so need to reduce LNG purchases. ‘Take-or-pay levels’ are thought to be around 85 per cent of contracted volumes, but can vary from contract to contract.

The price competitiveness of Australian producers is another factor affecting the outlook for Australia’s LNG exports. A large cost for LNG plants is feed gas. The three LNG export terminals on the east coast — which are largely fed by CSG from Queensland’s Surat and Bowen Basins— are thought to have relatively high costs for feed gas (in the vicinity of $5-6 a gigajoule or US$4-5 per MMbtu). Unlike LNG ventures using gas from conventional reservoirs, LNG operators on the east coast need to drill hundreds of new wells each year to maintain CSG production, with costs of over a million dollars per well.

Notes: Utilisation shown as a share of nameplate capacity. Office of the Chief Economist estimates of capacity are used while LNG trains are being commissioned. Source: Nexant (2017); Department of Industry, Innovation and Science (2018)

On current projections, Australia will overtake Qatar as the world’s largest LNG exporter in 2019, when Australian LNG exports reach 75 million tonnes. However, given the narrow difference between the projected exports of the two nations, Australia overtaking Qatar at this time is not certain.
Table 7.1: Gas outlook

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Notes: a JCC stands for Japan Customs-cleared Crude; b Production includes both sales gas and gas used in the production process (i.e., plant use) and ethane. Historical gas production data was revised in the June quarter 2017 to align with Australian Petroleum Statistics published by the Department of Environment and Energy; c Gas production from Bayu-Undan Joint Production Development Area is not included in Australian production. Browse basin production associated with the Ichthys project is classified as Northern market; d 1 million tonnes of LNG is equivalent to approximately 1.36 billion cubic metres of gas; e In 2017–18 Australian dollars; f Forecast; g 1 MMBtu is equivalent to 1.055 GJ; h In 2018 US dollars; s Estimate.

Source: ABS (2018) International Trade in Goods and Services, Australia, Cat. No. 5368.0; Department of Industry, Innovation and Science (2018); Company reports; Nexant World Gas Model (2017)