McKinsey&Company

Meeting east Australia's gas supply challenge

McKinsey Australia March 2017

Authored by:
João Segorbe
Peter Lambert

Meeting east Australia's gas supply challenge

McKinsey Australia March 2017

Contents

Preface . . . 1

Executive summary . . . 3

1. Stable long-term gas demand . . . 7

2. Falling gas supply . . . 17

3. Impact of meeting Australia's full demand potential . . . 23

4. Sufficient options available to serve east Australia's full demand potential . 27

Conclusion . . . 33

Appendices . . . 37


L N G

Preface

João Segorbe is a partner in McKinsey & Company's Perth office. Peter Lambert is a senior expert in McKinsey's Sydney office.

East Australia[1] is a gas market in transition. In the past, it was effectively isolated from the rest of the world and benefitted from relatively low cost local gas supplies. The ramp up of LNG trains in Queensland has effectively tripled gas demand from east Australia and linked the region to more volatile global gas markets. The local market has now fundamentally changed.

Future market dynamics have become less predictable. All market participants face challenges and a common understanding can help the discussion on next steps. This report aims to inform the debate on east Australia's gas market outlook between now and 2030 and move it forward by providing a fact base on the various demand and supply options. The analyses were developed based on external sources and tested through interviews with industry experts. This report addresses four questions:

- What are the likely scenarios for gas demand in east Australia (domestic and LNG)?
- What supply options exist to meet that demand?
- What are the differences between these supply options?[2]
- When do decisions on these options need to be taken to ensure an optimal outcome?

This report is the third in a series of reports on natural gas in Australia. It contributes to McKinsey's mission to support the communities we operate in by addressing important, yet challenging issues. As with all research published by McKinsey, this work is independent and has not been sponsored in any way by any business, government or other institution.

This paper has benefited from many sources of data and insight, and the authors are grateful for the perspectives from industry stakeholders including energy producers, consumers and policy makers.

McKinsey Partner Joao Segorbe (Perth) led this project with co-authors Peter Lambert (Sydney) and Daniel Hund (Melbourne). They were supported by a team consisting of Abhinav Charan, Andriy Dubyk and Nicholas Smith. For editing and graphics support, we thank Donald Simpson, Lisa Maconie, Liza Cornelius and Therese Khoury.

We are grateful for advice from McKinsey Energy Insights, and colleagues Alastair Levy, Alex Dorsch, Artika Thakur, Bartosz Dyrda, Berend Heringa, Christiaan Heyning, Christopher Handscomb, Clive Hilton, David Bailey, David Dyer, Dennis Ducro, Douglas Huey, Duncan Graham, Ellen Mo, Graham MacGregor, Helen Seidel, Kai Graylee, Michael Ellis, Michael Phillips, Mike Juden, Pru Sheppard, Rahul Gupta, Svein Harald Øygard, Ted Stephens, Torsten Teichmann and Yasir Mirza.

1 For the purposes of this report east Australia includes Queensland, New South Wales, Victoria, Tasmania, South Australia and the Australian Capital Territory. The gas markets of Western Australia and the Northern Territory are disconnected from the eastern market and are not covered in this report.

2 Demand reduction options also exist. Refer to Chapter 4 for details.

Executive summary

Meeting east Australia's projected gas demand requires choices to be made – and these will influence how the market will look in 2030

Demand for gas from east Australia is projected to remain flat from today to 2030 at a level of up to 2,155 PJ, of which 68 percent will be for LNG exports and 32 percent for domestic consumption. As current supply sources follow their normal declining course, new supply is needed to compensate. Over A$40 billion of planned supply investments over the next 15 years may not be enough. More developments are needed to meet east Australia's full demand potential – these needs add up to an estimated 465 PJ (21 percent of 2030 total gas demand forecast) required by 2030.

There are sufficient undeveloped resources and efficiency opportunities to meet east Australia's full demand potential. This gives a range of options, with each set of options leading to a different market dynamic and likely different price levels. Depending on the chosen path, expected price dynamics could range from a low case of local marginal cost of A$7–8 per GJ to a high case of parity with global markets. The latter could see prices reaching up to A$12 per GJ, and it could also expose the local market to international price volatility. It is worth noting that even local marginal cost pricing would likely see prices increase versus today's levels of A$5–6 per GJ.

Choices include the extent of energy efficiency and the rate of investment in resource developments

To keep gas prices as competitive as possible, east Australia could develop more supply and/or reduce its overall gas demand. Five sources to balance supply and demand are projected to have a total potential of ~2,200 PJ per year available for 2030, made up of:

- Additional east Australia supply: ~1,400 PJ with a breakeven price of A$5–11 per GJ
- Gas imports via FSRU[3]: ~150 PJ with a breakeven price of ~A$10 per GJ
- Demand reduction measures such as energy efficiency and fuel switching: ~250 PJ
- Demand destruction from likely industry closures in case prices rise consistently above A$9 per GJ: ~70 PJ
- Demand reduction by not fully utilising export capacity: 320 PJ at A$8–12 per GJ.

Of these options, some supply decisions and energy efficiency measures estimated at about 230 PJ are time sensitive. Decisions on these choices would be required by 2020 to take full effect by 2030. Delayed action could reduce the potential of some of the options available, which could lead to a higher breakeven price level and increase exposure to volatile global LNG markets through netback pricing.

3 Floating Storage Regasification Unit.

Pursuing time sensitive options by 2020 could enable a stable price level of around A$8 per GJ. If actions were delayed and/or did not address the full solution space, this could lead to prices in the range of A$8–12 per GJ and more price volatility. This could potentially result in higher energy cost for residential, commercial and industrial consumers as well as decreased competitiveness of some gas-intensive industries.

The analysis suggests that investment of at least A$10 billion in new developments could be needed on top of already planned investment of approximately A$40 billion over the next 15 years whether that investment is made early to supply the market's full demand potential from domestic sources or made later to deliver less supply from a reduced and more costly range of options.

To maximise the chances of a lower gas price outcome by 2030, the following options are available:

- Before 2020: develop offshore brownfield resources in Gippsland (90 PJ); implement energy efficiency measures so that they can deliver maximum energy consumption reduction by 2030 (140 PJ) (since these measures usually have a long lead time before having a material impact)
- From 2020 to 2025: develop greenfield CSG resources, which require development of new pipeline infrastructure, for example in Clarence-Moreton, Bowen or Surat basins
- From 2025 onwards: develop projects with existing infrastructure and relatively short lead times, including brownfield CSG and conventional onshore gas.

Making choices about energy provision and prices is difficult and involves trading off many different perspectives. A constructive discussion between stakeholders is therefore required. We hope this paper contributes to the discussion.

1. Stable long-term gas demand

Demand for gas from east Australia for domestic consumption and LNG exports is projected to remain flat through to 2030

Demand for east Australia's gas is driven by own consumption and LNG exports. Total gas demand in 2030 could reach up to 2155 PJ per year. Of that, domestic gas demand is set to be sustained at ~700 PJ per year,[4] with gas consumption for LNG exports ramping up to a possible total of 1455 PJ per year, of which 1135 PJ has been contracted long-term and 320 PJ is uncontracted capacity.[5]

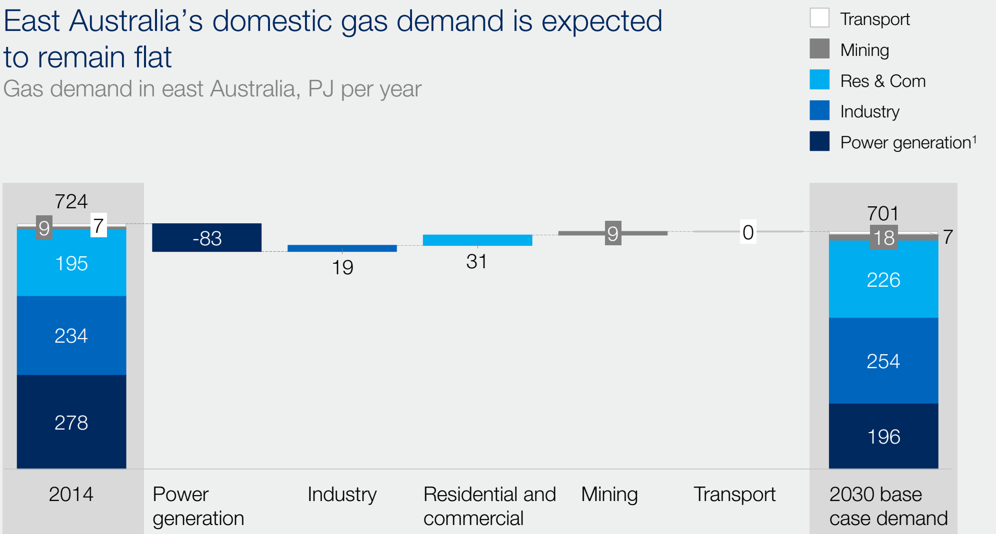
Domestic demand is projected to fall slightly due to lower consumption of gas in the power sector

East Australian domestic demand is projected at ~700 PJ in 2030, just below current demand levels.[6] The domestic gas market is comprised of five sectors: power, industrial, residential/commercial, mining and transport (Exhibit 1).

Exhibit 1

East Australia's domestic gas demand is expected to remain flat

Gas demand in east Australia, PJ per year



1 Gas demand in the power sector includes 37 PJ per year of off-grid generation, assumed as constant from 2014 to 2030

SOURCE: Office of the Chief Economist; CEDIGAZ; McKinsey GEP Model

4 Base case demand based on McKinsey's Global Energy Perspectives model.

5 Gas demand for the LNG liquefaction process has been included in the international demand.

6 Methodology and assumptions are consistent with the previous McKinsey Australia and Energy Insights report, *The role of natural gas in Australia's future energy mix*, June 2016.

Power

Projected gas demand from east Australia's power sector is based on McKinsey's Integrated Energy Model for Australia. This model suggests demand for gas in the power sector is expected to decrease from 278 PJ in 2014 to 196 PJ in 2030.[7,8]

Overall electricity demand in the NEM is estimated to increase from 193 TWh in 2014 to 210 TWh in 2030. Higher demand driven by GDP and population growth is set to be partially offset by expected improvements in energy efficiency, including lower consumption appliances and smart meter installations in households and commercial buildings. On the electricity supply side, a significant increase in renewable generation is expected from solar PV and onshore wind. This renewable generation growth is expected to decrease supply of electricity from fossil fuels in the power sector by 113 PJ in 2030.[9]

Industrial

Industrial demand for gas is projected to increase from 234 PJ in 2014 to 254 PJ in 2030, driven by economic growth partially offset by energy efficiency. Gas demand for industries that use gas as feedstock (such as ammonia and methanol) is assumed to remain flat, while gas demand from industrial sectors where gas is used as a heat source is projected to grow at between 0 percent and 0.5 percent CAGR.[10,11]

Residential and commercial

Gas demand from households and commercial buildings is projected to grow by 31 PJ to 226 PJ by 2030, making it the second largest gas consuming sector in 2030 after industry.

Population and GDP growth are likely to be partially offset by efficiency improvements in gas consumption. Technological improvements that increase the efficiency of space heating, water heating and cooking appliances can reduce consumption per household. These energy efficiency improvements are assumed to be adopted at 0.8 percent per year in the residential sector and at 0.6 percent per year in the commercial sector. Historically, east Australia's energy efficiency uptake has been modest, with gas use in the residential sector having increased by 1 percent per person per year since 2009,[12,13] despite the availability of energy saving measures.

7 Assumes unchanged regulatory framework.

8 Total power demand is from the NEM and off-grid gas powered electricity generation in east Australia. Off-grid generation mostly supplies electricity to towns and mining companies in north-west Queensland.

9 Decrease in coal demand by 70 PJ, gas demand by 41 PJ and oil demand by 2 PJ.

10 McKinsey's Global Energy Perspectives model.

11 This report assumes a lower rate of growth in industrial demand for gas than was shown in the previous edition of the Gas Insights Series. No new demand is assumed from ammonia or methanol production in east Australia given the current competitive environment for industries that use gas as feedstock.

12 Trading Economics, *Australia Population*, 2016.

13 Office of the Chief Economist, *Australian Energy Statistics*, 2016.

Mining

Gas demand in the mining sector is projected to double to 18 PJ in 2030. The mining sector currently makes up approximately 2 percent of gas demand. Estimated growth in the mining sector is assumed to range between 3–5 percent annually.

Transport

Demand for gas in east Australia's transport sector is expected to grow by less than 1 PJ from 2014 to 2030. The small increase in annual gas demand is expected to be driven by additional CNG powered vehicles and their increased utilisation. Expected demand growth for gas in the transport sector is limited by a lack of infrastructure to support gas-powered vehicles.[14]

Forecast sensitivities for domestic demand

Demand projections for 2030 are subject to a considerable level of uncertainty. Substantially higher gas demand could result from increased demand from transportation or the power sector, while lower demand could be driven by fuel substitution in the power sector or by increased energy efficiency measures.

Additional gas demand opportunities

As discussed in *The role of natural gas in Australia's future energy mix*, there are additional opportunities for increased gas use in east Australia. These could amount to an additional 191 PJ in the power and transport sectors resulting in a total potential domestic demand of up to 892 PJ in 2030.

Gas demand could increase by 95 PJ in east Australia's power sector from replacement of off-grid oil generation with new off-grid OCGT, on-grid oil with existing OCGT and some coal generation with increased gas plant utilisation.

Demand for natural gas in the transport sector could increase by 96 PJ in east Australia from additional uptake of NGV trucks, CNG buses and LNG mining trucks, trains and ships.

Several factors could lead to reduced gas demand in 2030

Domestic gas demand could reduce further compared to the estimated level of ~700 PJ in 2030 through additional demand abatement measures or demand reduction. Demand abatement measures include further improvements in building efficiency, power peak demand shaving,[15] or fuel switching (solar replacement of gas heating systems or renewable power generation, for example).

Industrial demand represents approximately one third of total domestic consumption. Of this, one quarter is susceptible to demand reduction if gas prices rise substantially,[16] from industries that use gas as a feedstock or as fuel for high heat intensity processes. These include ammonia-based industries (see Box 1).

---

14 The Energy Supply Association of Australia, *Developing a market for Natural Gas Vehicles in Australia*, 2014.

15 Gas demand in 2030 is estimated to be mostly used during peak demand hours with ~60 percent of gas consumption estimated to occur from 6AM to 9AM and from 5PM to 10PM. Peak shaving methods such as storage or demand side management would smoothen electricity demand and therefore reduce gas demand. Refer to Appendix C for explanation of the modelling methodology and relevant assumptions.

16 Of the 254 PJ per year projection for industrial demand, ~70 PJ per year of ammonia production and ~5 PJ per year of methanol production is at risk from a relatively modest prices rise.

Box 1: Competitiveness of ammonia plants

Ammonia production is one of east Australia's largest natural gas consuming industries, providing fertiliser for Australia's large agricultural sector. Natural gas is used as a feedstock for ammonia production, with ~31 GJ of natural gas required per tonne of ammonia produced.[17] The economics of ammonia production are highly dependent on natural gas prices, with 80 percent of the total cost typically coming from the natural gas feedstock.[18]

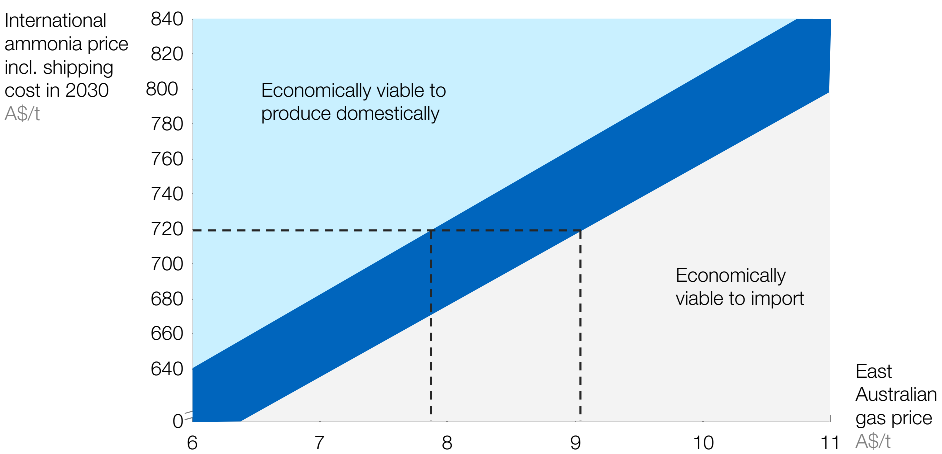
Ammonia producers operate plants in Queensland and New South Wales and employ ~2,500 people.[19] With a combined production capacity of ~2,400 kt per year,[20] the ammonia industry consumes ~70 PJ of natural gas per year, or about 30 percent of industrial demand.

Historical natural gas prices in east Australia have been economically favourable for ammonia producers. Rising gas prices, however, would reduce the profitability of east Australia's ammonia production. Future international ammonia prices are uncertain but assuming an ammonia price of A$690/tonne, Australia's ammonia producers start to lose international competitiveness at gas prices consistently above A$8-9 per GJ (Exhibit 2). Reflecting labour costs as well as energy costs, Incitec Pivot has already chosen to make its latest ammonia investment outside Australia – the ~A$1 billion WALA ammonia plant in Louisiana – which was completed in late 2016.[21] In the extreme, persistent high gas prices could result in the shutdown of east Australia's ammonia industry, reducing gas demand by ~70 PJ.

Exhibit 2

Ammonia imports become economically viable at gas prices above A$8–9 per GJ

Profitability comparison of domestically produced vs. imported ammonia[1]



1 Import prices for ammonia of A$690 per tonne and A$30 per tonne for shipping (real prices in 2030) compared with local production factors of 31 PJ per tonne gas intensity for feedstock and 10 PJ per tonne gas intensity for heat processing, A$17 per tonne non natural gas variable input costs, A$355 per tonne other input plant costs

SOURCE: IHS Markit (PEP 2016)

17 IHS Markit (PEP 2016).

18 IHS Markit (PEP 2016).

19 Office of the Chief Economist, Australian Energy Statistics, 2016.

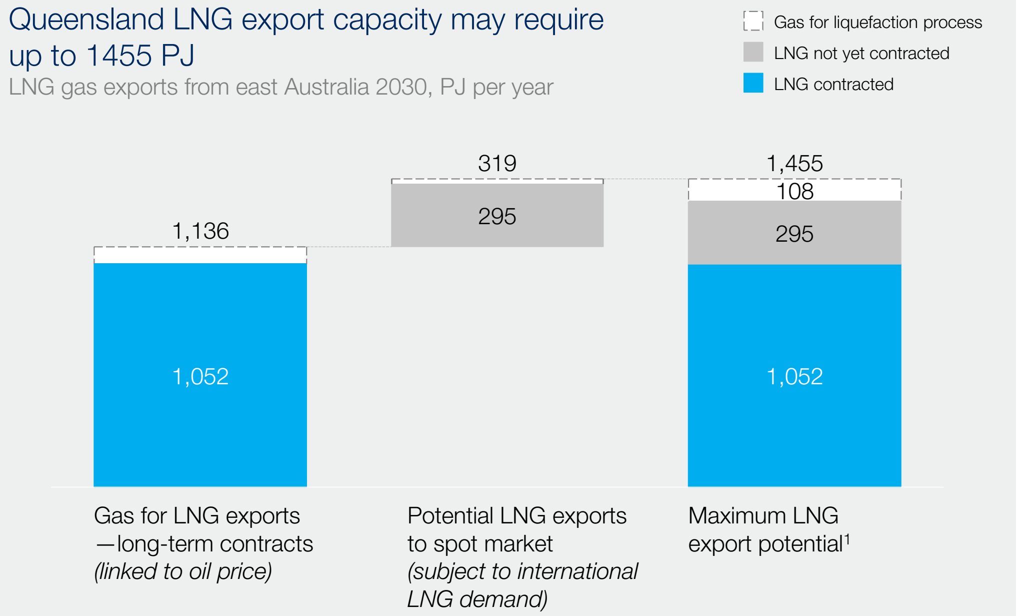
20 International Plant Nutrition Institute, *Nitrogen fertilizers: Supply and Demand*, 2015.

21 *Australian Financial Review*, Incitec Pivot's long-term bet pays off, 2015.

Queensland's LNG terminals have the potential to require up to 1,455 PJ of gas with most of this volume committed under long-term LNG contracts

LNG export demand has the potential to reach 1,455 PJ per year by 2030, which includes 108 PJ of gas for the operation of the liquefaction plants. This is made up of 1,136 PJ per year covered by firm long-term contracts,[22] under which volumes have already been sold far into the future. On top of this, the LNG plants in Queensland are estimated to have another 319 PJ per year of export capacity available, which can be used to produce LNG to sell on spot markets, or to supply additional longer-term contracts in the future (Exhibit 3).

Exhibit 3



1 Assumes 90% capacity utilisation; 8% production above nameplate capacity; 8% gas required for liquefaction process
SOURCE: CEDIGAZ; Lewis Grey Advisory

Contracted export demand

East Australia's LNG exporters[23] are reported to have contracts to supply east Asian gas buyers with 1,052 PJ per year, equivalent to 76 percent of total production capacity on a long term basis[24] with prices linked to oil prices.[25] Allowing for gas consumed in the liquefaction process, meeting these contracts requires the LNG terminals to consume 1,136 PJ per year.[26]

22 CEDIGAZ.

23 APLNG, GLNG, QCLNG.

24 CEDIGAZ; Lewis Grey Advisory, *Projections of Gas and Electricity Used in LNG Public Report*, 2016.

25 Oil-price linked LNG price formula: ~US$1 + ~0.14(JCC) (Lewis Grey Advisory, 2016). At ~US$70 per barrel oil price, this translates into ~AU$14 per GJ for gas under long-term LNG contracts.

26 Assumes 8 percent gas demand for liquefaction.

Uncontracted export demand

In addition to contracted demand, Queensland's LNG terminals have the potential to process a further 319 PJ per year, assuming 90 percent capacity utilisation and an effective capacity that is 8 percent above nameplate capacity. Experience from other onshore LNG terminals shows that effective capacity can typically reach up to 10 percent above nameplate capacity, with relatively small amounts of capital investment and time to de-bottleneck LNG processing facilities.[27] The extent to which this uncontracted capacity is used for exports depends on the outlook for the global LNG market.

Global LNG market outlook

Global LNG capacity additions in 2015–20, including 62 MTPA[28] of new Australian capacity,[29] contribute to an overcapacity of LNG globally.[30] This overcapacity has resulted in a reduction of LNG spot prices and reduced demand for new LNG contracts since 2015.

Nonetheless, LNG demand is forecast to grow by 4-5 percent[31] per year to 2030, with China, south Asia[32] and ASEAN driving the growth, due to increased gas penetration across household, industry, power and transport sectors. This rate of projected demand growth implies that by 2023 all existing and post-FID capacity[33] worldwide would be needed to meet demand, and an additional ~167 MTPA of new LNG would be required to meet demand growth to 2030. This equates to ~185 MTPA of liquefaction capacity addition, assuming a 90 percent utilisation rate at these facilities (Exhibit 4).

Such additional LNG capacity will only be built if the expected prices would give investors a sufficient financial return. McKinsey Energy Insights analysis suggests that a LNG price of ~US$8 per MMBtu[34] or higher is required to support the scale of capacity addition required (Exhibit 5). This translates into ~A$10 per GJ assuming an exchange rate of US$0.75 per A$1.00.

27 Origin Energy, *Investor Day and Site Tour*, 2016.

28 LNG volumes are normally quoted in MTPA (million tonnes per annum). 1 MTPA LNG = 55 PJ.

29 Additional capacity from APLNG, QCLNG, GLNG, Wheatstone LNG, Gorgon LNG, Prelude FLNG and Ichthys LNG.

30 The Australian Oil and Gas Review, *Global major warns of LNG oversupply*, 2013.

31 McKinsey Energy Insights estimates LNG demand growth from 2016 to 2030 at 4.6 percent CAGR, similar to CEDIGAZ (4.2 percent CAGR). Each basis point of demand sensitivity represents 0.51 MTPA. In a scenario with only 1.4 percent LNG demand growth, additional capacity requirements in 2030 would reduce to zero.

32 South Asia includes Bangladesh, India and Pakistan.

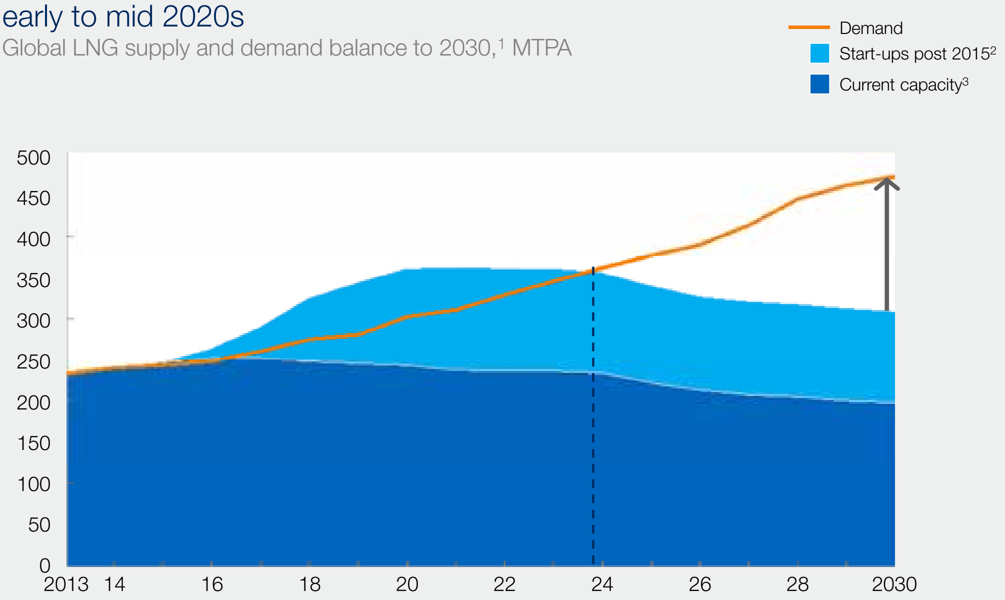
33 Post-FID capacity represents LNG capacity for which the Final Investment Decision (FID) has been taken before 2016.

34 LNG prices are normally quoted in US$ per Million British Thermal Units (MMBtu). 1MMBtu = 1.055 GJ.

Exhibit 4

New LNG capacity is forecast to be needed from the early to mid 2020s

Global LNG supply and demand balance to 2030,[1] MTPA

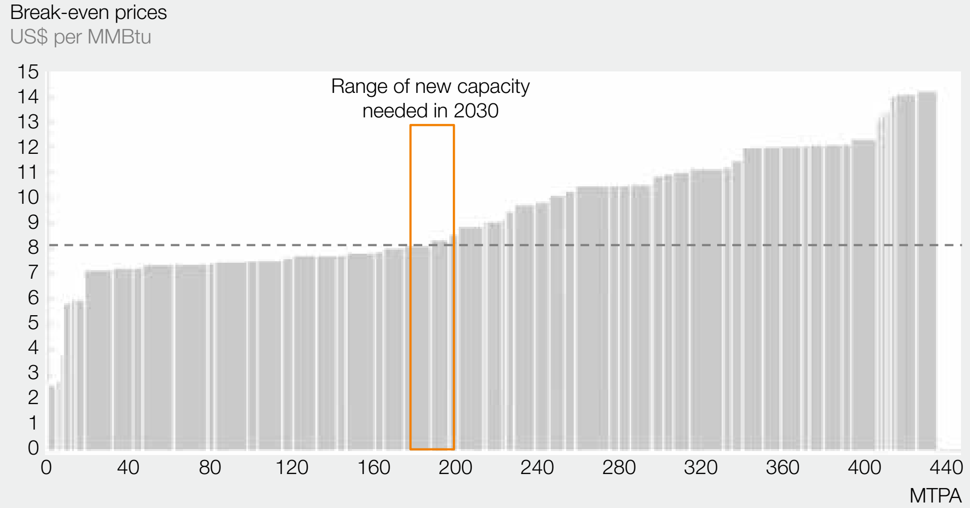


1 On stream supply is based on the analysis of gas available for exports after domestic demand is met
2 New liquefaction projects are expected to produce at 50% of capacity in year one and 90% of capacity in following years
3 Existing projects output is expected to decline as several LNG exporters are projected to experience feed gas supply constraints
SOURCE: Energy Insights' Global Gas Model

Exhibit 5

Cost curve for potential LNG developments suggests LNG prices of greater than US$8 per MMBtu are required to attract the required new capacity

Long run marginal cost curve of new LNG developments[1]



1 LNG break-even prices delivered ex ship to Asia; gas demand calculated based on oil price of US$70 per barrel; excludes projects under construction or in operation
SOURCE: Energy Insights' Global Gas Model

Historically, LNG market prices have varied widely, with prices rising towards an oil price equivalent 'ceiling' during periods of supply shortage (e.g. 2008–9, 2012–14), and falling back towards a European spot price 'floor' in over-supplied LNG markets (e.g. 2009–11, 2015–16).[35] An uncertain LNG demand outlook, long construction lead-times and large capital commitments provide strong indications for LNG price cycles to continue in future.

This leaves a wide range of LNG price uncertainty over the next 15 years, reflecting uncertainty around future oil prices, the price difference between LNG spot price and an oil price ceiling and the timing of price recovery from currently low levels. If LNG prices were to reach 85-90 percent of the oil price ceiling, this would translate to US$10-11 per MMBtu (~A$14 per GJ) in east Asia, assuming an oil price of ~US$70 per barrel.

LNG netback pricing

East Australian LNG producers will respond to market conditions when deciding whether to use the uncontracted capacity in their plants. The difference between the cost of incremental gas supply in east Australia and the price it can be sold at outside Australia, minus shipping and liquefaction costs, will drive their decisions. An LNG price of US$8 per MMBtu in Asia would translate to a 'netback' value of A$8–8.5 per GJ for gas entering a Curtis Island terminal in Queensland, after taking account of exchange rates, shipping costs and energy used in liquefaction. Companies with spare capacity to export LNG would therefore be expected to pay up to A$8 per GJ in Queensland to export it profitably to Asian markets (Exhibit 6).[36]

In case of an Asian LNG price that approaches the oil price ceiling, the netback value could reach approximately A$12 per GJ at oil prices of ~US$70 per barrel, implying companies with available LNG export capacity would be willing to pay up to A$12 per GJ for gas supply in Queensland.[37]

If New South Wales and Victoria become dependent on Queensland gas supplies to meet local demand then prices in those states could be set at a premium over Queensland, reflecting inter-state gas transmission costs. See Appendix E for state level analysis of future gas supply and demand.

35 U.S. Energy Information Administration, *Natural gas prices in Asia mainly linked to crude oil, but use of spot indexes increases*, 2015.

36 Assuming an LNG price of US$8 per MMBtu.

37 Assuming LNG spot market prices to range between 85-90 percent of the oil price ceiling.

Exhibit 6

Netback value of LNG exports could be A$8–12 per GJ by 2030

Overview

	LNG spot net back price[1] A$ per GJ		Remarks
	Expected LNG 2030 spot price	~10	▪ 2030 JKM[2] LNG spot price: ~A$10 per GJ ▪ 85-90% of oil price ceiling : **~A$14 per GJ**
1	Shipping	~1	▪ Tanker lease: A$0.8 per GJ ▪ Losses: 0.15% boil-off per day @ 10 days delivery to Japan
2	Liquefaction	0.5–1	▪ Cash cost only ▪ ~8% energy needed to liquefy LNG @ gas price of ~A$8 per GJ
3	LNG spot netback price	8–8.5	▪ Could range up to **A$12 per GJ** in an under-supplied global LNG market

1 Oil price: US$70 per bbl; US$0.75 per A$1.00
2 Japan Korea Marker
SOURCE: Energy Insights' Global Gas Model; Excelerate Energy. L.P.; ICIC; Drewry LNG Shipping Insight

□ □ □

As outlined above, gas demand for domestic consumption and LNG exports is likely to be sustained to 2030. The next chapter analyses upstream gas production capacity to meet this demand.

2. Falling gas supply

Supply capacity from existing gas fields and expected developments is set to decline by 16 percent, falling short of east Australia's full demand potential by ~465 PJ in 2030

Projected gas supply capacity in 2030 is based on capacity from existing fields, fields that are under development and fields that are viewed as probable developments. Assets in the latter category are expected to obtain development approval within 5 years.[38]

East Australia's gas supply capacity from these assets is ~2,010 PJ in 2017, and is projected to fall to ~1,690 PJ in 2030. The difference between falling supply capacity and total potential demand (given the steady long-term outlook for gas demand) is estimated to be 465 PJ in 2030.

Gas supply from producing facilities is in decline – and under development and planned reserves are not enough to replace it

East Australia's gas supply capacity is projected to fall from ~2,010 PJ in 2017 to ~1,690 PJ in 2030 (Exhibit 7). The decline is concentrated in offshore (-8.1 percent CAGR) and onshore conventional (-3.8 percent CAGR) as both groups enter a period of steady natural decline reflecting the effects of reservoir depletion and asset maturity. Coal Seam Gas (CSG) assets, mostly linked to Curtis Island LNG projects, are projected to maintain a flat production profile until 2030, underpinned by planned capital investment of approximately A$40 billion.[39]

Offshore

Offshore production is currently drawn from fields in the Bass, Gippsland and Otway basins, contributing ~405 PJ in 2017. A steep decline in supply from producing assets/areas is expected, including Bass Strait, Casino Area, Halladale Area, Minerva, Otway Gas Project and Yolla.[40] This decline is partly offset by new production, expected from Gippsland basin through the ongoing development of Kipper field and the probable development of Sole field. Reflecting the net effect of new developments and depletion, offshore production is projected to fall to 136 PJ in 2030, amounting to an 8.1 percent annual decline rate. The decline rate for offshore gas could be reduced to 4–5 percent if brownfield potential in Gippsland and Otway basins were developed. These assets are currently classed as 'technical resources' with no firm plans for development.

38 As classified in Wood Mackenzie – Upstream Data Tool Q3 2016.

39 Includes both existing and planned CSG assets committed to LNG projects in east Australia. Underinvestment or delay in pre-FID projects ('probable developments') could result in lower than estimated gas supply.

40 Bass Strait is projected to decline at an average 6.6 percent per year between 2017 and 2030. During this time, Casino Area, Halladale Area, Minerva, Otway Gas Project, Sole and Yolla are projected to cease production. Kipper is expected to start production in 2017 and produce until 2030.

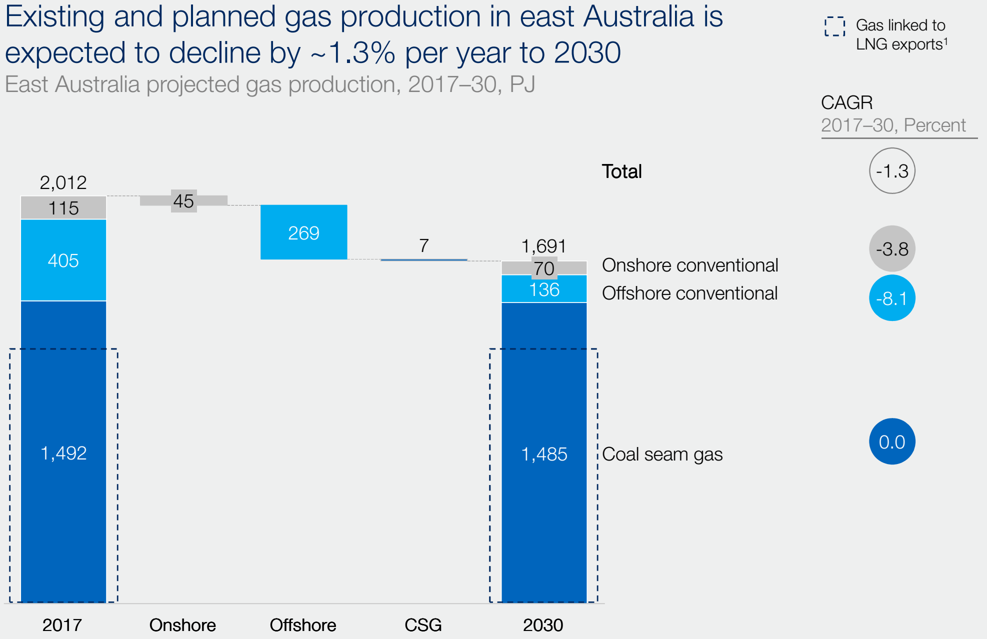
Onshore conventional

Onshore production, including conventional and tight gas production, is estimated to contribute ~115 PJ in 2017. With no new developments planned, production from mature fields is set to decline. The decline is partly offset by planned investment in brownfield assets, including Cooper basin. The net effect results in a 3.8 percent annual decline rate, leading to ~70 PJ production in 2030. Further slowing the decline rates from onshore conventional fields would require investment in wells, workovers and renewal of surface infrastructure.

Exhibit 7

Existing and planned gas production in east Australia is expected to decline by ~1.3% per year to 2030

East Australia projected gas production, 2017–30, PJ



1 Gas dedicated to exports: 2017: 1246 PJ per year, 2030: 1323 PJ per year

SOURCE: Wood Mackenzie—Upstream Data Tool Q3 2016

Coal Seam Gas

Projected Coal Seam Gas production for 2030 is almost unchanged at 1,485 PJ in 2030 compared to 1,492 PJ in 2017. The bulk of this production is drawn from the Bowen-Surat basins in Queensland followed by the Clarence-Moreton basins in Queensland and New South Wales and ongoing production from Sydney basin in New South Wales. In addition to currently producing fields, probable developments such as Ironbark and Western Surat Gas Project are expected to contribute to new CSG production, offsetting natural decline.

By 2030, nearly 90 percent of CSG supplies will be linked to the three LNG Curtis Island plants. Since CSG wells have a relatively short lifespan ongoing capital investment in new wells is required to sustain production from CSG resources.

Existing and planned gas developments require a domestic gas price of up to A$5–7 per GJ to breakeven

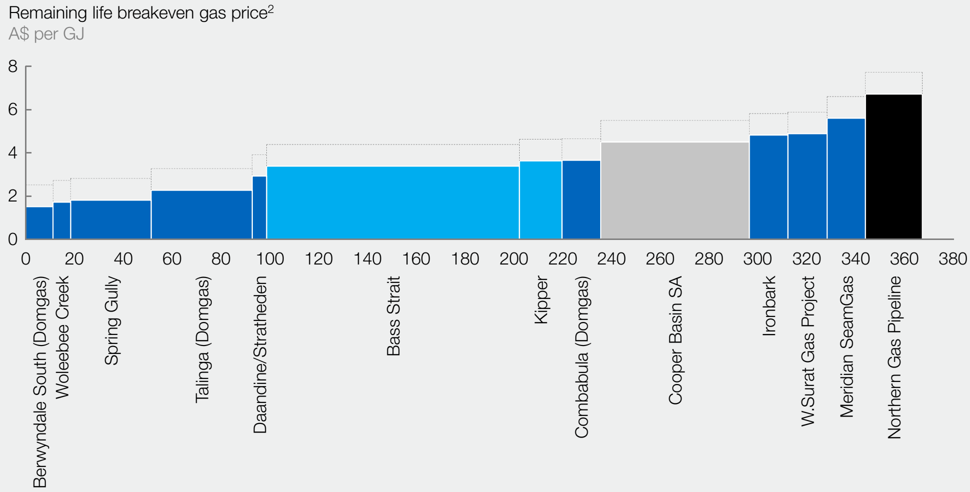
Of the ~1,690 PJ projected supply capacity in 2030, ~1,320 PJ of CSG production is linked to LNG export facilities in Curtis Island. The remaining production would be directed to domestic consumption.

Breakeven prices have been calculated to reflect forward looking economics of supply that is not linked to LNG (Exhibit 8). Breakeven prices for existing and planned developments vary widely, reflecting the level of sunk costs inherent in many existing assets and the capital intensity of new projects.

Exhibit 8

Existing fields and planned developments could require prices of A$5–7 per GJ to breakeven

Existing & planned gas supply cost curve, 2030, PJ



1 Upper range is based on an additional A$1 per GJ to address effective PRRT payable, additional infrastructure costs (e.g. pipelines) and sensitivities in the cost structure

2 Based on costs from 2017 onwards only

SOURCE: Wood Mackenzie—Upstream Data Tool Q3 2016

A cost curve showing existing and planned supply indicates a wide range of breakeven prices, with the more marginal resources requiring prices in the range of A$5–7 per GJ. Producing onshore assets such as a Berwyndale South and Talinga are at the lower end of the cost curve. Offshore assets in the Bass Strait lie in the middle of the curve. Assets under development such as Kipper have higher breakeven prices as future development capital expenditure must be recovered. Probable developments such as Ironbark and Western Surat Gas Project lie on the right hand side of the cost curve. In addition to production within east Australia, gas supply of ~23 PJ per year from existing and planned developments in the Northern Territory supplied via the planned Northern Gas Pipeline (NGP) has been included in the analysis.[41]

41 Full capacity of the NGP is 32 PJ per year, however the capacity shown here has been limited to 23 PJ per year from existing and planned resources in the Northern Territory that can be supplied through the pipeline.

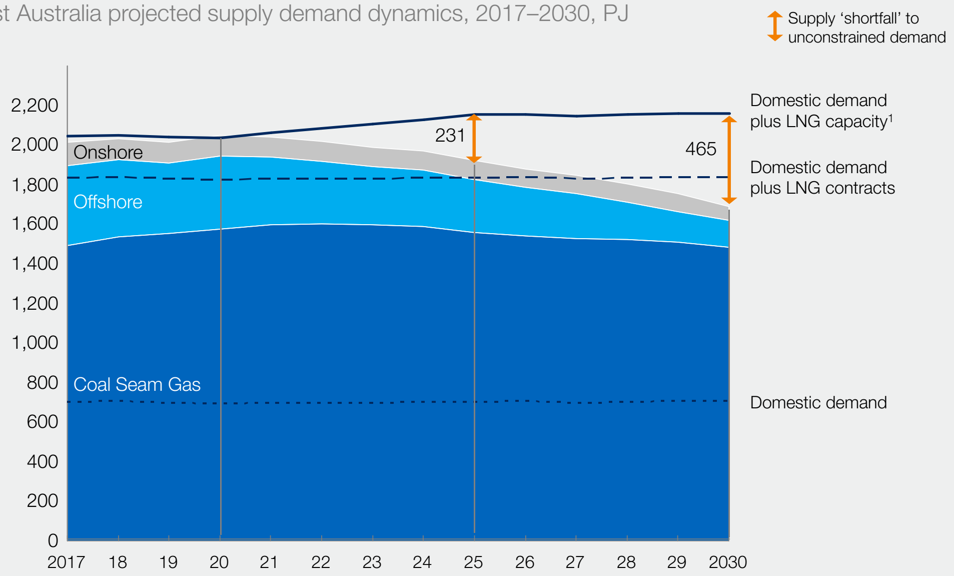
By 2030, the difference between projected gas supply and full demand potential is projected to reach 465 PJ

Given the demand outlook to 2030, projected supply is insufficient to meet the full potential of domestic and export demand (Exhibit 9). In the near-term, with current export capacities, supply and demand are broadly in balance. A difference is projected to open up from 2020 as conventional production declines more steeply and export capacity expands beyond nameplate levels, reaching ~230 PJ in 2025 and ~465 PJ in 2030. In a high domestic gas demand scenario, the difference would grow more quickly, reaching ~650 PJ by 2030.[42]

Exhibit 9

Existing and planned capacity is insufficient to fill all export capacity and to meet domestic demand

East Australia projected supply demand dynamics, 2017–2030, PJ



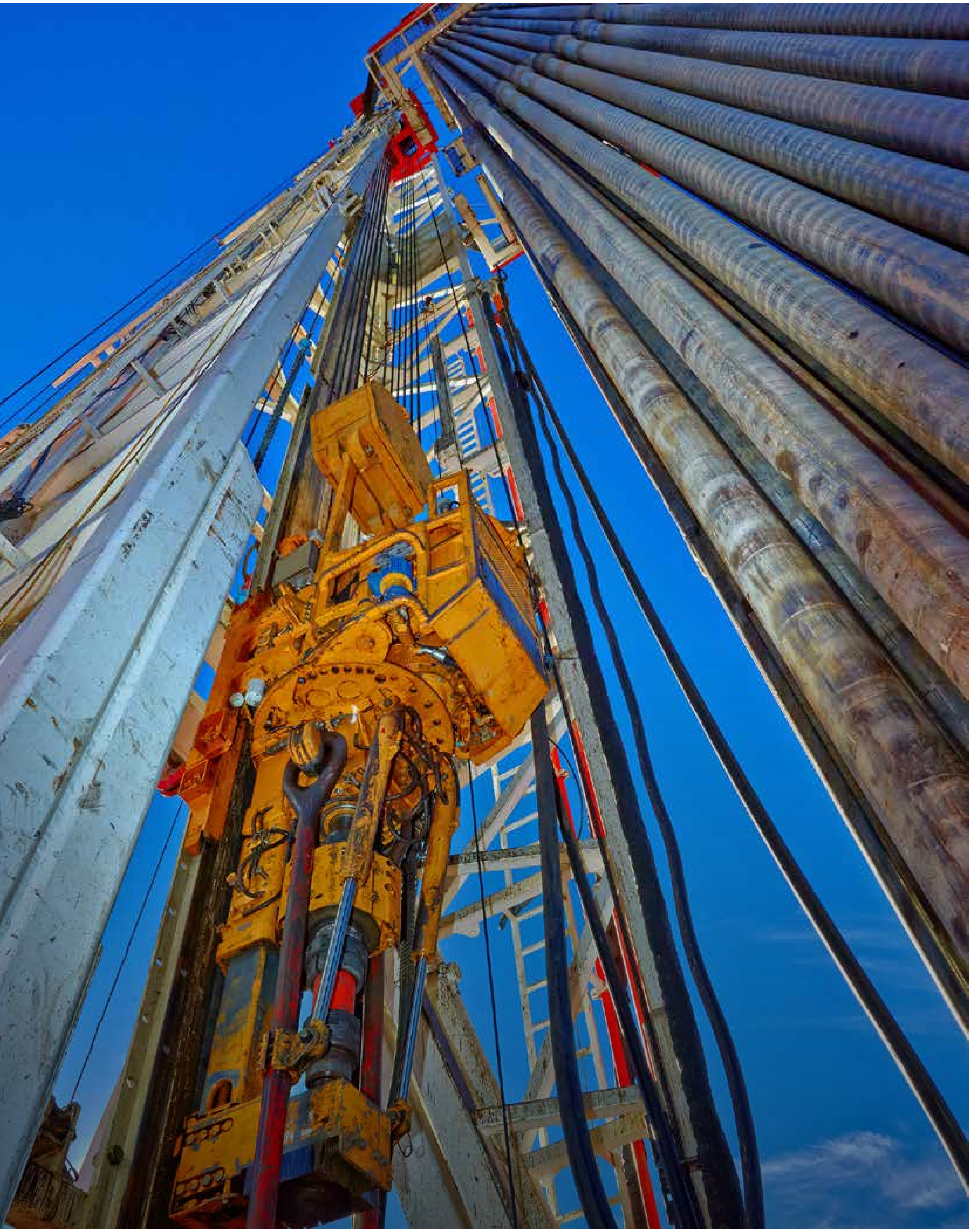
1 Assumes capability to produce above nameplate capacity developed between 2020-25

SOURCE: CEDIGAZ; Wood Mackenzie—Upstream Data Tool Q3 2016

□ □ □

The following chapter considers the implications of a 465 PJ difference between projected gas supply and full demand potential for east Australia.

42 High domestic demand scenario includes 191 PJ of additional gas in the transport and power sector outlined in Chapter 1.



3. Impact of meeting Australia's full demand potential

Supplying more of east Australia's full demand potential would affect energy price dynamics, increase government and community income, and sustain employment in both energy producing and consuming industries

With the depletion of low-cost conventional supplies, gas costs in east Australia are set to be substantially higher in the future than they have been in the past. A large difference between gas supply and full demand potential could make this situation worse. All else being equal, lower availability of gas would tend to push up domestic gas prices to export market levels. Much higher gas prices could damage the competitiveness of gas-consuming businesses, potentially placing jobs in gas-intensive industries at risk. On the other hand, increased gas production would lead to higher employment in gas-producing industries and increase the income earned by communities and government from investment activity in the gas sector and from taxes and royalties.

Historically low gas prices are unlikely to be sustained in the future

Historically, east Australia has benefitted from lower gas prices than most other areas of the developed world. Between 2008 and 2013, Victoria's gas market prices averaged A$3.3 per GJ,[43] compared to wholesale prices equivalent to A$5.2 per GJ, A$9.7 per GJ and A$18.6 per GJ in the US, Europe and Japan respectively[44] over the same period.[45,46,47]

Past low prices resulted from the relatively plentiful availability of low cost conventional gas supplies. As discussed in the previous chapter, this situation is changing. Conventional gas supply capacity is in steep decline and higher cost unconventional supply sources represent an increasing share of future supply capacity. Existing and planned gas supply sources require marginal gas prices of A$5–7 per GJ to cover their future capital and operating costs. Any new resources that are not yet scheduled for development are likely be more costly, requiring market prices of A$7–8 per GJ or more. East Australia's gas prices have already begun to rise but a price increase from today's levels of A$5-6 per GJ to A$7–8 per GJ may be unavoidable in the absence of major technological breakthroughs.[48]

---

43 Australian Energy Market Operator, *Short Term Trading Market Prices*, 2016.

44 The Victoria gas market is an imperfect indicator of overall market prices in east Australia as the majority of gas sales take place under long-term contracts outside the declared market. However, average gas sales prices reported by east Australian gas producers show similar values. The US gas price is for Henry Hub, the European price is the German border price (BAFA), the Japanese price is average LNG import price.

45 U.S. Energy Information Administration, *Henry Hub Natural Gas Price*, 2016.

46 BAFA, *Monthly development of prices*, 2016.

47 FGE, Asian *LNG DES Price*, 2016.

48 Today's price levels of A$5–6 per GJ are already higher than historical price levels of A$3–4 per GJ.

A large difference between gas supply capacity and full demand potential could push prices higher

Gas supply and demand will ultimately reach a balance. Increasing supply capacity normally takes more than 2–3 years. Therefore a large difference between gas supply capacity and full demand potential is likely to be bridged in the shorter term by reducing demand. Some domestic users may reduce their consumption or LNG export terminals may operate below their full capacity.

A large difference between supply capacity and full demand potential would create an environment where the market must optimise between domestic market sales and LNG exports. In this situation, the economic cost of curtailing exports is likely to set the price in the domestic market. With LNG markets expected to rebalance in the early to mid-2020s,[49] the economic cost of reducing exports would be significant. Assuming a ~US$70 per barrel oil price and delivery costs to Asia, the economic cost of reducing spot LNG sales is likely to be in the A$8–12 per GJ range, depending on spot market conditions. The cost of reducing contracted LNG sales is likely to be approximately A$12 per GJ.

Measures to narrow the difference between gas supply and full demand potential could have positive effects

Anticipating and acting early enough gives access to a wider array of measures to reduce the supply gap: incremental supply can be brought onstream or energy efficiency measures can be taken to reduce domestic gas needs. New supply is likely to be more costly than the existing and planned reserves considered in the previous chapter and energy efficiency measures may require regulatory support. For the remainder of this chapter it is assumed, that supply capacity and demand potential can be brought into balance at price levels of A$8 per GJ or below and that the vast majority of existing industrial demand remains commercially viable at A$8 per GJ.

Meeting the full demand potential while avoiding demand destruction would allow the gas market to meet domestic demand, serve international LNG export markets and avoid exposure to global gas price volatility. It would have positive effects on government and community revenues, gas price levels and energy costs and on sustainability of employment.

Government and community revenues

Increased investment in gas production capacity has potential to create higher government and community revenues. Precise figures are dependent on individual company cost structures and tax positions. However, developing additional gas resources could add up to ~A$1 billion of government revenues in 2030 from royalties and Petroleum Resource Rent Taxes (PRRT). Payroll and corporate taxes could create a further ~A$0.4 billion of government income. Finally, local suppliers and investors could earn ~A$1.2 billion in revenues from supporting the development of new resources and life extension of existing assets.[50]

49 Refer to Chapter 1 for more details on LNG market dynamics.

50 A revenue analysis for unconventional gas projects for LNG exports identifies 26 percent of revenues from LNG flow to the government as rent tax and royalties, 11 percent of revenues are payroll and corporate taxes and a further 32 percent flows to local suppliers supporting the LNG supply chain. Taking a gas price of A$8 per GJ and assuming ~465 PJ unserved demand potential, total revenue could be as high as A$3.7 billion. McKinsey & Company, *Extending the LNG boom: Improving Australian LNG productivity and competitiveness, 2013.*

Sustainability of employment

Higher wholesale gas prices create a more challenging market environment for gas intensive industries. As discussed in Chapter 1, ammonia production, which is relatively sensitive to gas prices, risks losing international competitiveness for wholesale gas prices above A$8–9 per GJ. Gas intensive industries employ up to 3,500 people directly and support up to 4,000 indirect jobs in east Australia.[51,52] While the outlook for these industries is subject to developments in their individual markets, achieving an outcome that limits wholesale gas price rises to A$8 per GJ or below can help sustain these jobs.

Adding gas supply can also sustain upstream employment. Late life assets in the offshore Gippsland basin are due to be gradually decommissioned during the 2020s and 2030s. Investing in sustaining production from those assets could help support up to ~500 existing jobs operating those fields. Investing in development of onshore gas resources could also add ~1,300 direct oil and gas jobs.[53] Another 3,600 indirect jobs are dependent on these investments, based on typical job multipliers in the oil and gas operations.[54]

Price levels and energy costs

As low-cost gas supplies deplete, gas prices are expected to rise. As discussed above, a large difference between gas supply capacity and full demand potential could push price levels to the A$8–12 per GJ range. Taking measures to narrow the difference through incremental supply, improved energy efficiency and electrification of LNG liquefaction process could limit future price levels to A$8 per GJ or below. A wholesale price rise from ~A$4 per GJ to ~A$12 per GJ would increase energy costs by up to ~A$4.7 billion per year. Limiting the wholesale price rise to A$8 per GJ would result in an increase in wholesale energy costs of A$2.7 billion.[55]

□ □ □

In this chapter we have assumed that the full demand potential can be served at a price of A$8 per GJ or less. In the next chapter, we quantify the measures available to achieve this.

51 Business and Economic Research Limited, *Updated manufacturing multipliers report*, 2012.

52 Office of the Chief Economist, *Australian Energy Statistics*, 2016.

53 Job estimate is based on development of CSG resources.

54 Office of the Chief Economist, *Review of the socioeconomic impacts of coal seam gas in Queensland*, 2015.

55 Using a 2030 expected gas demand under assumed price increase from historic gas prices of A$4 per GJ to potential future prices of up to A$12 per GJ for domestic supply.

4. Sufficient options available to serve east Australia's full demand potential

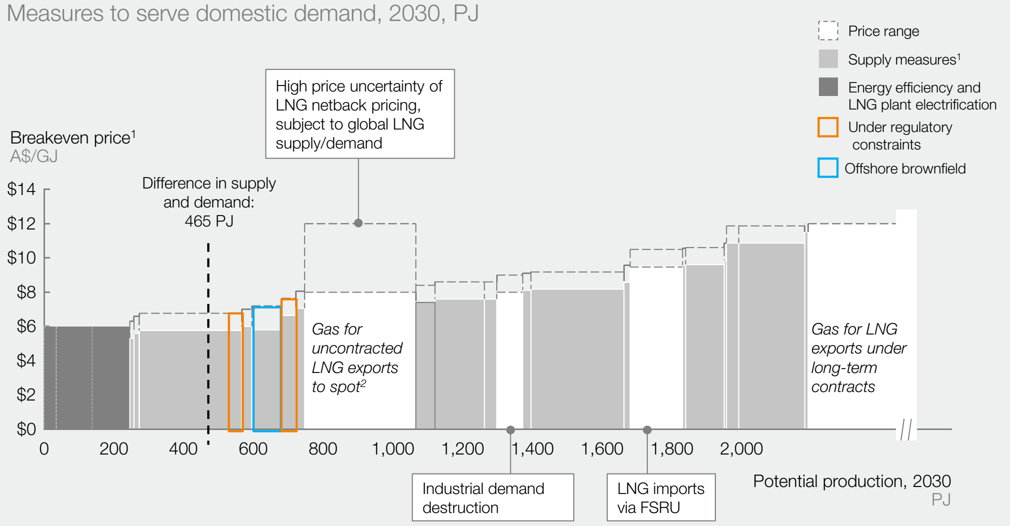
Several options would allow east Australia to meet its total gas demand and avoid the high-end of projected future gas prices

Demand and supply measures can contribute to closing the ~465 PJ difference between planned supply capacity and full demand potential in 2030. Supply side measures include development of new gas resources in east Australia, primarily from CSG resources in Queensland and increased production from existing resources such as the offshore Gippsland basin. On the demand side, the main opportunities come from increasing energy efficiency for both gas and electricity, leading to a reduction in gas demand from the power sector, residential and commercial consumers and electrification of the LNG liquefaction process. Measures with breakeven prices below A$8 per GJ could fully address the supply demand difference (Exhibit 10).

Exhibit 10

Sufficient options exist to meet additional 465 PJ gas demand

Measures to serve domestic demand, 2030, PJ



1 Includes new developments, pipeline from NT and LNG imports via FSRU
2 Gas from long-term LNG contracts is available only at higher domestic gas prices
SOURCE: Wood Mackenzie—Upstream Data Tool Q3 2016

Supply side measures have the potential to provide up to three times the unserved demand potential at varying breakeven price levels

East Australian gas resources that are not currently planned for development have the potential to produce ~1,400 PJ by 2030. Gas from the Northern Territory via the Northern Gas Pipeline and LNG shipments via floating storage regasification units (FSRU) could bring in additional volumes, albeit at higher breakeven gas prices. With abundant supply options, breakeven economics amongst other factors can assist in prioritising potential measures.

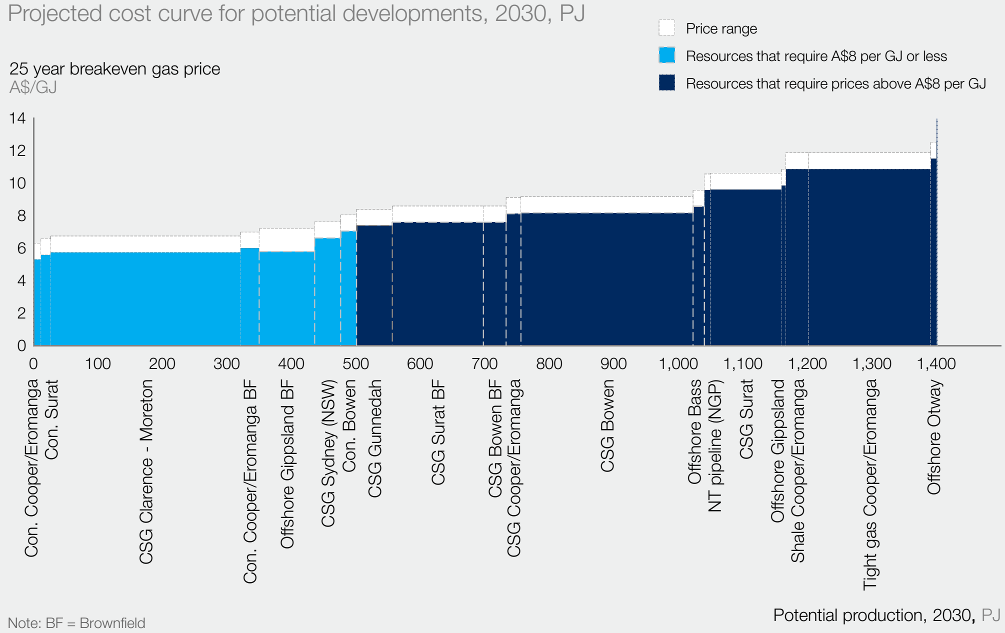
'Potential' developments include three categories of assets: (i) technical resources of producing or brownfield assets that are not part of 'planned' developments, (ii) assets which are wholly classified as 'good technical' and (iii) assets which are wholly classified as 'contingent'. Based on the 'potential' cost curve analysis,[56] sources of potential supply are segmented into two tranches reflecting breakeven gas prices (Exhibit 11).

Exhibit 11

ESTIMATES

Developing CSG and offshore brownfields could substantially address the supply gap below the expected netback price

Projected cost curve for potential developments, 2030, PJ



Note: BF = Brownfield

SOURCE: Wood Mackenzie—Upstream Data Tool Q3 2016

Resources that require a price of A$8 per GJ or less

Supply potential of ~500 PJ in 2030 has been identified with a breakeven below A$8 per GJ. Most of this resource comes from the Clarence-Moreton basin in Queensland and New South Wales (~290 PJ), brownfield resources in the Cooper-Eromanga basin (~30 PJ), brownfield resources in the Bass Strait/Gippsland basin (~90 PJ) and Sydney basin in New South Wales (~40 PJ).[57]

The investment required to fully develop and sustain production from this resource is estimated to be ~A$13–15 billion for ~500 PJ in 2030.[58]

56 See Appendix D: Supply modelling methodology and assumptions for details.

57 Significant local opposition to shale development in NSW together with regulatory restrictions could be a barrier to new development in Sydney basin and Clarence-Moreton basins. Nonetheless they remain among the range of options available to balance east Australia's gas supply and demand.

58 See Appendix D: Supply modelling methodology and assumptions for details.

As for all unproven hydrocarbon resources, there are uncertainties associated with each of these opportunities. For example, development may prove more complex than expected or flow rates from new wells may fall short of expectations, both of which would increase the breakeven price. At the same time, there is potential for cost reductions through technological progress, via learning from other similar resources and from operator efficiencies that may reduce breakeven prices.

Among the lower cost 'potential' developments, offshore Gippsland brownfield is unusual: it is time sensitive. The assets are approaching end-of-field life and, as they come closer to Cessation of Production (COP), it becomes less attractive for developers to invest in incremental resources as the time remaining to earn a return is curtailed. In the case of Gippsland brownfield, an investment decision would need to be made soon to avoid a significant increase in breakeven price as the remaining lifetime of the asset shortens.

Resources that require prices above A$8 per GJ

The remaining ~900 PJ in the 'potential' cost curve comes mainly from CSG, tight gas, shale gas and offshore gas. CSG is concentrated in Bowen-Surat basins, with an estimated ~380 PJ production potential in 2030. Additional CSG supply is expected from the Cooper-Eromanga and Gunnedah basins. Tight gas in Cooper-Eromanga basins is estimated to produce ~190 PJ if developed. Other sources in this segment include offshore resources in Bass, Otway and Gippsland basins, shale gas in Cooper-Eromanga basins and tight gas in Gippsland basin – which is subject to the ban on onshore unconventional gas in Victoria.

While these resource options are estimated to have a higher breakeven cost than other options in the cost curve, they should continue to be monitored. Ongoing efforts to improve CSG development techniques and to increase development efficiency could allow some of these resources to lower their breakeven cost over the next 5–10 years. Resources in this group also offer an alternative source of domestic supply in case some of the apparently lower-cost basins would disappoint in terms of resource volume or development cost.

Pipeline from the Northern Territory

In addition to 23 PJ per year of 'existing and planned' production projected to flow through the Northern Gas Pipeline (NGP) included in Chapter 2, the pipeline can carry a further 9 PJ of capacity supplied from technical resources in the Northern Territory. Allowing for upstream development costs as well as pipeline tariffs, this supply has an expected breakeven at A$10–11 per GJ. No new pipeline options were included in the potential supply assessment.

Floating Storage Regasification Units (FSRU)

FSRUs offer a flexible option for increased supply and can be activated with a relatively short lead time. LNG imports via an FSRU could add as much as ~150 PJ per year.[59] The cost of LNG imports would reflect global LNG prices, with the addition of FSRU rental fees and capital costs of onshore gas receiving facilities. FSRU imports have a breakeven above the netback economics of LNG exports from Queensland. An FSRU is estimated to breakeven

59 Assuming one FSRU operating at 80 percent utilisation. In case more volumes are required several FSRUs could be contracted.

at ~A$10 per GJ. While this is more costly than other supply options, it could serve a role in meeting regional imbalances if a substantial price premium emerges in Victoria/NSW as compared to Queensland.

Demand measures can also play a role in reducing the unserved demand

The main opportunities for material demand abatement come from incremental energy efficiency, accelerated replacement of gas in the power sector and electrification of the LNG liquefaction process in Queensland's LNG export facilities. Together they can further reduce gas demand by up to ~250 PJ, although regulatory intervention may be needed to capture the full extent of the possible reductions.

Incremental energy efficiency

Energy efficiency measures amounting to 2 percent of demand per year in the residential and commercial sector could reduce overall demand by 35 PJ by 2030. Efficiency measures are particularly relevant in Victoria, which accounts for ~70 percent of east Australia's residential/commercial gas demand.[60]

International benchmarks for gas efficiency have been set by Germany and California. In Germany, improved efficiency and solar solutions for space heating have reduced gas consumption by 2.2 percent CAGR between 2000 and 2013.[61] Policy measures have also been put in place to implement energy efficient construction of new buildings. Efficiency measures in California which require gas retailers to help customers reduce natural gas use and mandate improvements in appliance and building efficiency have decreased residential and commercial gas consumption by 4.1 percent CAGR and 1.0 percent CAGR respectively between 2010 and 2015.[62]

Residential/commercial demand for gas and power is fairly inelastic with limited changes to demand resulting from higher gas prices, due to a relatively low share of wallet of gas and electricity (~3 percent),[63] reduced carry-through of wholesale prices to retail prices (~30 percent)[64] and the upfront capital costs of many energy saving measures. Substantial improvements in energy efficiency are unlikely without government interventions to incentivise or mandate them.

60 Office of the Chief Economist, *Australian Energy Statistics*, 2016.

61 Fraunhofer ISI, *Energy Efficiency trends and policies in Germany*, 2015.

62 Energy Coalition, *Energy Efficiency Annual Report*, 2016.

63 Australian Bureau of Statistics, *Spending patterns*, 2013.

64 Bureau of Resources and Energy Economics, *Eastern Australian Domestic Gas Market Study*, 2013.

Accelerated replacement of gas in power generation[65]

Power modelling suggests demand for gas in the power sector could be as low as 93 PJ in 2030 in case measures are taken to reduce gas dependence. This could reduce overall gas demand in the power sector by 103 PJ compared to the base case.[66] The measures to lower power sector demand for gas include: increasing deployment of renewable generation through solar/wind, installing efficient electric appliances and increasing use of demand side management to shave peak demand.

Increased deployment of renewable energy sources would reduce the need for gas-fired generation during periods of high power demand, coinciding with solar and wind electricity generation. Installation of efficient electric appliances would reduce total demand in the power sector, which would reduce fossil fuel demand.[67] Since gas is used mostly to meet peak demand, demand-side management measures and energy storage solutions would reduce gas demand further by offsetting peaks.

Electrification of LNG liquefaction process

As outlined in Chapter 1, the LNG liquefaction process in Queensland's LNG export facilities is energy intensive and is set to consume up to 108 PJ gas, if the total LNG export capacity is used.[68] Electrification of the liquefaction process, using electrical compressors instead of gas compressors would allow up to 108 PJ of gas consumption to be replaced with up to ~20 TWh of electricity.[69] The additional gas could be used to serve domestic gas demand or to fill LNG export capacity. The additional electricity required for such a switch in the liquefaction process could be generated by an increase in utilisation of coal-fired power generation, albeit at the expense of increased carbon emissions.[70]

□ □ □

This chapter established that sufficient measures exist to address the full demand potential in east Australia with a price range lower than A$8 per GJ. The next chapter considers the implications if some measures are not pursued or delayed.

65 As outlined in Chapter 1, gas demand in the power sector is subject to high uncertainty reflecting future market structure and regulatory framework. Accelerated replacement of gas power generation could make the phase out of more CO2 intensive coal-fired generation slower and more costly.

66 Refer to Appendix C for explanation of the modelling methodology and relevant assumptions.

67 Includes coal-fired and gas-fired power generation.

68 LNG exports under long-term contracts would require ~85 PJ of gas for liquefaction, with a further ~23 PJ gas demand for liquefaction of uncontracted demand.

69 Total efficiency of electrical compressors assumed at 1.26 tonnes of LNG per GWh (el.) compared to gas turbines with an efficiency of 0.88 tonnes of LNG per GWh (el.). Total required electricity consumption for liquefaction of contracted and uncontracted LNG volumes is estimated to be ~20 TWh. ABB Group, *All electric LNG plants, 2006*.

70 Assuming 81 percent capacity utilisation of existing 8.2 GW coal fired power stations in Queensland and no decommissioning of plants through to 2030.

Conclusion

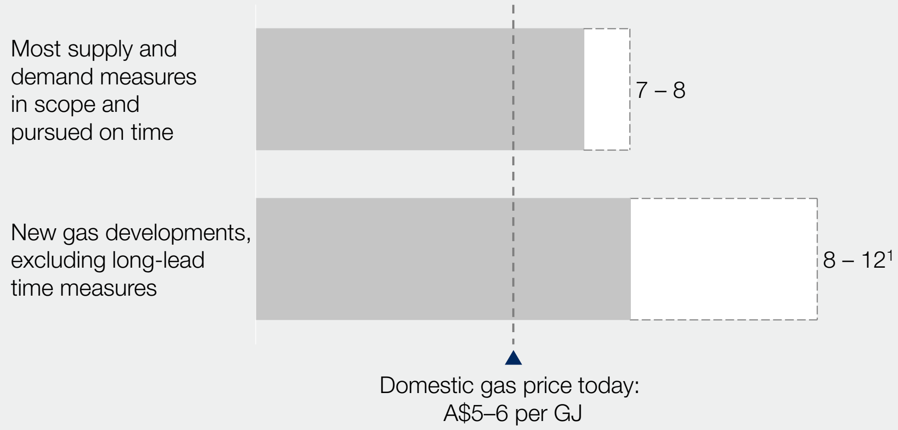
Prompt action can reduce the likelihood of higher prices: options to ensure a local marginal cost pricing mechanism require action within the next couple of years; waiting will most likely drive the market to international LNG parity

Sufficient measures to meet east Australia's full demand potential exist at breakeven prices below A$8 per GJ but the margin is relatively small – an estimated ~750 PJ of measures would be available to cover a 465 PJ difference. Some of these measures are time sensitive. Prompt action to implement a set of measures that are currently available can bring long term supply and demand into balance with prices set by marginal domestic supply sources. Delayed action would reduce the potential of some of the options available, which could lead to a higher breakeven price level and increasing the exposure to volatile global LNG markets through netback pricing (Exhibit 12).

Exhibit 12

Domestic gas prices in 2030 expected to vary depending on measures taken

2030 domestic gas price, under different future scenarios, A$ per GJ



1 ~ A$8 per GJ netback under equilibrium; ~ A$12GJ net back at LNG prices at 85–90% oil price ceiling

Time sensitive options

All measures outlined in Chapter 4 are theoretically feasible. However, the potential of some of the lower cost options will reduce over time affecting their possible impact by 2030. Time sensitive measures fall into three categories: producing assets approaching end-of-field life, long lead-time demand measures and long lead-time supply measures.

Producing assets approaching end-of-field life

As discussed in Chapter 4, brownfield investment in offshore Gippsland has the potential to contribute ~90 PJ of incremental supply in 2030 through increased production from existing fields. However, the production facilities in offshore Gippsland have a limited remaining lifespan. Most were developed in the 1960s–80s[71] and this infrastructure is estimated to be gradually decommissioned through the 2020s and 2030s. Typically, at least 10 years of remaining field life is required to recover a significant brownfield investment. The economics of brownfield investment become more challenging as remaining field life reduces.

Long lead time demand measures

Chapter 4 outlines demand measures worth ~140 PJ from incremental energy efficiency and accelerated replacement of gas in power generation.

Measures to improve energy efficiency tend to have a cumulative effect as inefficient equipment is replaced and energy waste is reduced. Experience from other markets suggests that regulatory changes will be required to capture the full potential and these would take time to agree and implement.[72] Any delay in implementing energy efficiency measures would reduce the potential in 2030.

Long lead time supply measures

Greenfield gas developments require construction of new production and pipeline infrastructure that is likely to require 3–5 years between Final Investment Decision (FID) and first gas production. Legislative restrictions affecting coal seam gas in New South Wales and Victoria could also extend the lead-time for those measures if pursued. Taken together, these sources under legislative restrictions account for ~80 PJ in 2030.

Impact of delays and constraints on measures

Whether action is taken promptly or is delayed, an incremental investment of ~A$10 billion is likely to be required before 2030. Meeting the region's gas demand requires development of new capacity (or implementation of demand reduction measures). A decision would need to be made on when and where to invest.

As discussed in Chapter 4, options exist for east Australia's full 2030 demand potential to be met through, for example, 325 PJ of incremental supply and 140 PJ of reduced demand from energy efficiency measures. Promptly implementing those options could require upstream investment of ~A$10 billion on top of the ~A$40 billion already planned as well as regulatory support for improved energy efficiency. Taking these measures would lead

71 ExxonMobil, Changing Role for Bass Strait.

72 Fraunhofer ISI, Energy Efficiency trends and policies in Germany, 2015.

to east Australia's wholesale gas prices being set predominantly by the cost of marginal domestic supply, estimated at ~A$7–8 per GJ. Higher international LNG prices would have little impact on domestic gas prices as LNG terminals would run at full capacity.[73]

In the event of a delay in making the necessary choices, less demand reduction potential from energy efficiency measures would be available, and more of the demand potential must be met through new supply.

Without low cost brownfield investments and development of CSG in NSW, and assuming that delays limit the demand reduction potential to 140 PJ by 2030, all of the remaining ~325 PJ of supply measures with a breakeven up to A$8 per GJ would need to be developed.

If the potential from demand reduction measures was to fall below 140PJ then a market balance would likely require arbitrage between domestic and LNG markets. Such arbitrage would link domestic and LNG market prices. As outlined in Chapter 1, LNG prices would need to reach the equivalent of A$8 per GJ to attract new investment during the 2020s but they could range up to A$12 per GJ in a supply-constrained LNG market. Experience suggests price movements within this range could be relatively volatile.

73 Refer to Appendix E for a state level breakdown of the supply and demand outlook under such a scenario.

Appendices

Appendix A: List of acronyms

AEMO	Australian Energy Market Operator
APLNG	Australia Pacific LNG
APPEA	Australian Petroleum Production & Exploration Association
ASEAN	The Association of Southeast Asian Nations
bbl oil	Barrel of oil
Bcf	Billion cubic feet
bcm	Billion cubic metres
boe	Barrel oil equivalent
CAGR	Compound annual growth rate
CAPEX	Capital expenditure
CCGT	Combined cycle gas turbine
CNG	Compressed natural gas
COP	Cessation of production
CSG	Coal seam gas
FID	Final investment decision
FSRU	Floating storage regasification unit
GDP	Gross domestic product
GEP	Global Energy Perspectives
GJ	Gigajoule
GLNG	Gladstone LNG
GW	Gigawatt
JCC	Japan customs-cleared crude
kt	Kilo tonnes
LCOE	Levelised cost of electricity
LNG	Liquefied natural gas
LPG	Liquefied petroleum gas
LRET	Large-scale Renewable Energy Target
MMBtu	Million British thermal units
mmcf	Million cubic feet
MTPA	Million tonnes per annum
Mt CO2-e	Million tonnes of CO2 equivalent
MWh	Megawatt-hours
NEM	National Electricity Market
NGP	Northern Gas Pipeline (previously NEGI)
NGV	Natural gas vehicle
NPV	Net present value
NSW	New South Wales
NT	Northern Territory
OCGT	Open cycle gas turbine
PJ	Petajoule
PRRT	Petroleum Resource Rent Tax
PV	Photovoltaic
QCLNG	Queensland Curtis LNG
QLD	Queensland
SRMC	Short run marginal cost
t	tonne
TWh	Terawatt-hours
WA	Western Australia

Appendix B: Unit conversions

Currencies

A$ 1 = US$ 0.75

Energy and gas volumes

1 PJ = 1 x 10^6 GJ	1 GWh = 0.0036 PJ
1 boe = 6.11786 GJ	1 t LNG = 55 GJ
1 toe = 41.868 GJ	1 Mt LNG = 55 PJ
1 MMBtu = 1.0551 GJ	1000 MMSCFD = 6.972 MTPA
1 kWh = 0.0036 GJ	

Appendix C: Demand modelling methodology and assumptions

Overview of modelling approach

The analysis in this report was conducted using McKinsey's analytic tools and modelling expertise, drawing on data and assumptions gathered from external sources and proprietary insights from the firm's experts. The demand assumptions for the base case and high demand case are taken from the previous McKinsey report *'The role of natural gas in Australia's future energy mix'* from June 2016, with exception of a revision to the industrial demand outlook.[74] Gas demand only includes east Australian gas demand, defined as gas demand for Queensland, New South Wales, Victoria, South Australia, Tasmania and the Australian Capital Territory. Domestic demand is end-use only and does not include gas requirements for processing or extraction.

An additional downward sensitivity analysis of gas demand in the power sector was conducted considering the impact of more aggressive renewable uptake and energy efficiency assumptions. Incremental insights were derived from McKinsey's proprietary model of power generation in the NEM.[75]

Australian power market model

Analysis of the east Australian power sector was conducted by modelling the National Electricity Market (NEM), while keeping the remaining off-grid gas demand for power generation in east Australia constant.

Power demand

The power demand projection was calculated based on a modified bottom-up energy consumption forecast of the previous base case outlook. Power sent out was adjusted to total generation after factoring in self-consumption by power plants, distributed and captive

74 The previously projected increase in gas demand for new build ammonia plants by 25 PJ in 2030 was revised to zero, given recent investment decisions of major industry players and a gas price sensitivity analysis for ammonia production (see Chapter 1, Exhibit 2).

75 The gas demand for power generation outside the NEM was treated as independent of any additional analysis and is identical with the previous report. McKinsey Australia and Energy Insights, The role of natural gas in Australia's future energy mix, June 2016.

generation and transmission and distribution losses. Load profiles were forecast based on overall macroeconomic trends, improvements in energy efficiency and the impact of distributed generation.

Generation capacity

The power supply mix was optimised by the model to satisfy total electricity demand to ensure sufficient capacity for peak-loads, provide security margin and minimise the total system cost.

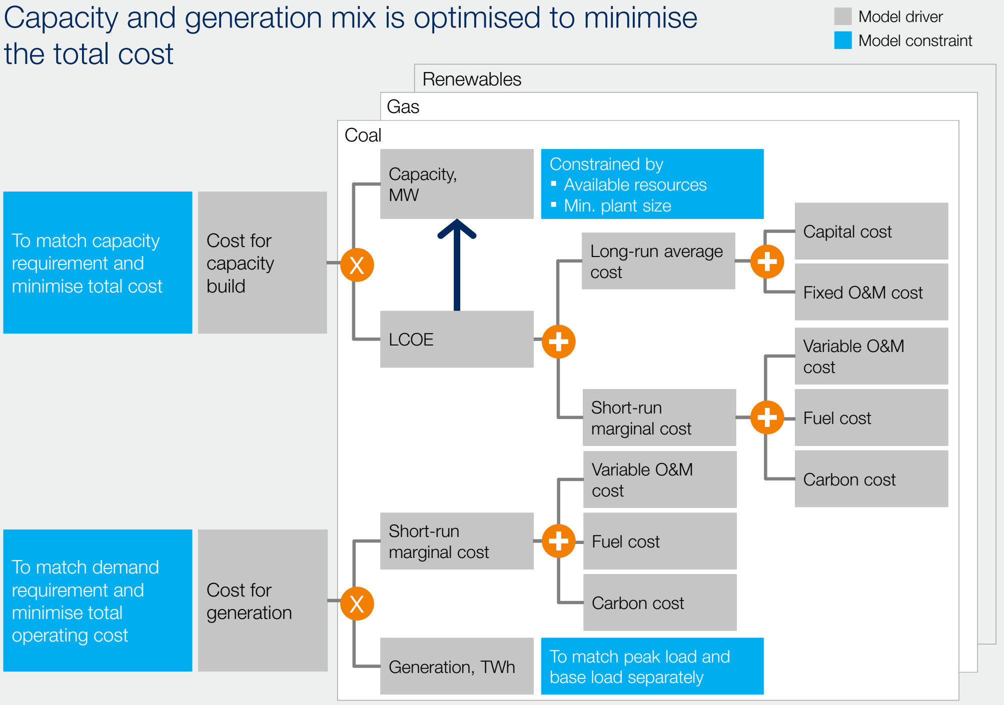
The capacity mix projection takes into account the retirement schedule of existing generation capacity based on their economic lifetimes and the pipeline of new projects to meet the LRET by 2020. The model adds capacity based on the expected LCOE of different technologies and retires capacity based on the total system benefit (or cost) for keeping a plant available. Constraints are added to the model to ensure projects meet minimum plant size per unit.

Generation dispatch

Generation is dispatched according to the merit order of the short-run marginal cost (SRMC) of installed technologies, permitting operational constraints. Each technology is constrained on dynamic ramp up and down rates, as well as maintenance and resource availability. The model assumes that wind and solar generation are fully dispatched, based on historic generation traces, to encourage renewable project development (Exhibit 13) – except when generation needs to be curtailed given demand and ramp-up profiles of other generation.

Exhibit 13

Capacity and generation mix is optimised to minimise the total cost



SOURCE: McKinsey Electric Power Natural Gas Practice, Australia 2030: The road ahead for the power sector

References

In addition to input from McKinsey's proprietary databases, functional practices and experts, and the results from the previous McKinsey report on *'The role of natural gas in Australia's future energy mix'*, the following references were used to inform the low gas demand Australian power market scenario:

- Australian Energy Market Operator (AEMO)
- Energy Exemplar PLEXOS® Integrated Energy Model for Australia
- Australian Energy Regulator (AER)

Appendix D: Supply modelling methodology and assumptions

Overview of modelling approach

Like the demand analysis, the analysis of east Australian gas supply was conducted using McKinsey's analytics and modelling expertise drawing on data and assumptions gathered from external sources and proprietary insights from the firm's experts.

Separate supply cost curves we developed for 'Existing and Planned' and 'Potential' supply sources using data from Wood Mackenzie's upstream data tool. Interviews with McKinsey's experts were used to test and refine the analysis.

Supply cost curves include supply sources within east Australia including Queensland, New South Wales, Victoria, South Australia and Tasmania. They also include gas supply capacity to east Australia from the Northern Territory via the under construction Northern Gas Pipeline (NGP). No other pipelines from outside east Australia were considered.

All costs are shown on a 'go forward' basis from 2017, ignoring previous spend as 'sunk' costs. The 'Existing and Planned' cost curve calculates the gas breakeven price based on remaining field life whilst the 'Potential' cost curve estimates the breakeven price based on a 25 year field period including the field development phase. Cost curves show potential production capacity in the year 2030.

'Existing and Planned' supply cost curve

The **'Existing and Planned' cost curve** considers sales gas supply sources from 'producing' fields, projects 'under development' (post-FID) and 'probable developments' (field which is expected to receive development approval within a five year time frame). The cost curve is focussed on supply for domestic consumption and excludes supply that is committed to LNG export plants.

For the 'Existing and Planned' cost curve, the horizontal axis shows the estimated 2030 gas production based on lifetime production profile. The vertical axis shows the gas price required to ensure a breakeven between costs and revenues from 2017 until end-of-field life based on a net present value (NPV) analysis.

Any costs incurred prior to 2017 including development capital expenditure or operating expenses are treated as sunk costs. Costs associated with abandonment of existing assets are also treated as 'sunk' for the purposes of this analysis. Liquid credits are considered where considered appropriate (e.g. Cooper basin). Royalty for onshore basins estimated at 10 percent, discount rate is assumed to be 10 percent including weighted average cost of capital (WACC) and any inflation effects. Discounted cash flow is used to calculate the breakeven price of gas to arrive at a net present value of zero.

The Northern Gas Pipeline (NGP), connecting Tennant Creek in the Northern Territory to Mt. Isa in Queensland, is included in the 'Existing and Planned' cost curve. The pipeline is estimated to have ~32 PJ per year nameplate capacity of which ~23 PJ is considered 'Existing and Planned' supply. Gas supply is assumed to be sourced from the Amadeus Basin and surplus gas contracted by Power and Water Corporation, NT (from Blacktip). Expected transportation tariffs for gas from Bonaparte basin combines published tariffs from Amadeus, NGP and Carpentaria pipelines.

The analysis does not consider any unconventional gas sources in NT which are currently subject to moratorium on hydraulic fracturing. Pipelines from Western Australia were also excluded from the cost curve because of high cost, questionable availability and existing domestic gas reservation policy.

'Potential' supply cost curve

The **'Potential' cost curve**[76] considers sales gas supply sources which are classified as 'contingent' (not expected to be developed under current circumstances due to poor economics or gas that is likely to be reinjected) or 'technical' (reserves which could be developed in the future). Any production volumes tied to producing assets but classified as 'technical' are also included in this category. For example, brownfield technical reserves in the Bass Strait would fall under this category.

Capacity of the NGP that is not used by existing or planned production (~9PJ) has also been considered as 'Potential' supply. Supply to use this capacity could be sourced from new developments in Bonaparte basin.

The horizontal axis shows the 2030 gas production volumes available based on a lifetime production profile (Exhibit 11). Assets below a materiality threshold of 5 PJ per year have been excluded.

The vertical axis shows the gas price required to match costs and revenues for the field on an NPV basis over a 25 year period including the development phase. Development capital expenditure is included in the analysis. Similar to 'Existing and Planned' cost curve, abandonment costs are not included. For contingent assets, analogue developments have been utilised to estimate capital and operating costs and the corresponding production profile.

Estimation of capital expenditure for contingent sources is based on current technological capabilities. While technological innovation and management practices could lower unit capital and operating costs, the analysis takes a conservative view on costs for such developments. At the same time, it is worth recognising that despite likely technological progress, some of the contingent sources might never get developed within our timeframe of interest.

76 (1) Assets with less than 5 PJ production potential (onshore Bowen-Surat brownfield, onshore Otway, CSG Maryborough, CSG Galilee-Drummond, tight gas Bowen-Surat Brownfield, tight gas Gippsland, shale gas Carpentaria, shale gas Cooper/Eromanga, offshore Otway brownfield) were excluded from the cost curve. Combined production potential of excluded fields is approximately 40 PJ in 2030. (2) Both Queensland and New South Wales figures considered for Clarence-Moreton basin. NSW resources in Clarence-Moreton could supply 37 PJ in 2030.

The model assumes that onshore conventional, unconventional and CSG need 1–2 years for project development (FID to first gas). This range accounts for pipeline construction in currently non-producing areas. Potential offshore developments are assumed to take 2–3 years before first gas production.

Capital estimates for resource development are based on analogues and external data sources. For contingent resources, analogue fields were analysed for unit capital and operating costs. These figures were adjusted to account for the specific type of the asset, its complexity and contingent nature. Thereafter, the adjusted unit costs were multiplied with recoverable gas volumes (provided by external data source) to estimate the lifetime capital expenditure and operating expenses. The capital expenditure and operating expenses were distributed over estimated field life on an annual basis based on assumptions on asset characteristics and production profile respectively.

The analysis does not factor in any impact associated with site accessibility challenges for CSG or project delays, which could increase the breakeven price and change the relative positions of certain sources on the cost curve.[77]

Floating Storage and Regasification Unit (FSRU) solution

Cost estimates are based on a leased FSRU unit which receives LNG shipments in NSW or Victoria from LNG terminals within the region, e.g. Gladstone, Northwest shelf, or Western Australia. FSRU was considered a 'Potential' solution given its scalability and agility relative to a permanent onshore regasification facility.

Assumptions include: (1) Capital expenditure for onshore receiving facilities at US$75– 100 million; (2) One FSRU unit with 500 mmcf per day of regasification capacity delivering ~160 PJ per year at 80 percent utilisation rate.

References

In addition to input from McKinsey's proprietary databases, functional practices and experts, the following references were used to inform the analysis of future gas supply to east Australia:

- CEDIGAZ, *LNG databases*
- NSW Department of Industry, *Official website*
- Victoria Government, *Official website*
- Wood Mackenzie, *Upstream Data Tool,* Q3 2016

Appendix E: East Australia supply demand outlook at state level

As described in Chapter 5, east Australia's full 2030 demand potential could be met by 325 PJ incremental supply and 140 PJ of reduced demand from energy efficiency measures, for example. Domestic gas prices would likely be set by marginal supply with limited impact from LNG markets on domestic gas prices. However, the state by state pattern of supply and demand would look different in 2030 compared to today.

77 Based on analogues, redevelopment CAPEX for offshore brownfield in Gippsland is assumed to be 65–85 percent of CAPEX estimates for greenfield development.

Methodology

Supply demand analysis on a state level was conducted for 2017 and 2030. Gas demand in 2017 is compared to 'existing and planned' supply. 2030 supply includes 'potential' production in addition to 'existing and planned' supply and 2030 demand reflected 140 PJ of potential energy efficiency measures beyond what is included in the base case. Supply options that are subject to regulatory constraints and that are time-sensitive have been excluded, as well as supply measures above A$8 per GJ.

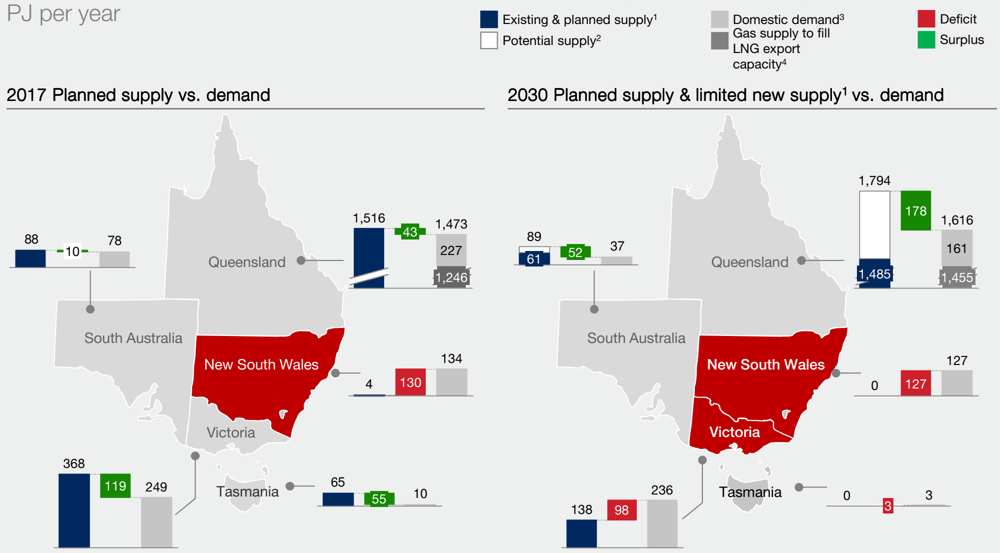
State level overview

Under the assumptions outlined above, Victoria would see the biggest change in the supply-demand balance between today and 2030. Rapid declines in supply from offshore Gippsland reduce Victoria's production capacity, leaving it with a net import requirement of ~100 PJ per year. Similar declines in the Otway and Bass basins effectively eliminate Tasmania's gas export capacity. With little change in New South Wales' supply demand balance, Queensland and South Australia are the main candidates to increase gas sales to gas deficient states (Exhibit 14).

Exhibit 14

NSW and VIC expected to be most severely affected by delayed decisions on new supply measures and an absence of regulatory changes

PJ per year



1 2030 figures include 'Existing and Planned' supply as described in Appendix D
2 Includes only new gas developments with break-even lower than A$8 per GJ; excludes supply under regulatory constraints (onshore Victoria supply, Sydney and Clarence-Moreton basins in NSW) and time-sensitive supply measures (Gippsland offshore brownfield)
3 Base case gas demand as described in Chapter 1 minus 140 PJ of demand reduction from efficiency measures
4 CSG supply committed to LNG exports (see Exhibit 7)

SOURCE: Wood Mackenzie; Office of the Chief Economist

Queensland

Queensland is estimated to retain a supply surplus in 2030, driven by planned and potential CSG supply and reduced domestic demand. In 2017, Queensland is expected to produce ~1,800 PJ. Of this supply ~1,460 PJ is consumed by LNG terminals and ~160 PJ is set to serve Queensland demand, creating a surplus of ~180PJ. Electrification of LNG export terminals could increase Queensland's supply surplus further.

South Australia

South Australia's supply surplus rises from ~10 PJ in 2017 to ~50 PJ in 2030, driven by reduced demand and planned and potential supply from Cooper-Eromanga basins.

New South Wales

Stable demand and no new supply developments leave a ~130 PJ gas import requirement in 2030, similar to the 2017 requirement. Development of potential CSG resources in the Sydney and Clarence-Moreton basins, assumed to be not developed in this analysis, could change this pattern materially.

Victoria

With stable domestic demand and declining production, Victoria is projected to move from being the largest net exporting state in 2017 to being highly dependent on supply from neighbouring states by 2030.

Tasmania

Natural decline from offshore Otway and Bass basins and no new developments mean Tasmania would lose the capacity to export gas by 2030.

ABOUT MCKINSEY ENERGY INSIGHTS

Energy Insights

Energy Insights provides insights across the entire energy value chain to help energy players make strategic decisions, identify areas for performance improvement and capture value for each of their individual assets. Energy Insights combines McKinsey's global energy expertise, proprietary data, tools and a dedicated team of experts to deliver the custom information clients need for business planning and decision-making.

McKinsey Australia
March 2017

Design contact: New Media Australia
www.mckinsey.com