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# Is Australia quietly quitting the LNG business?

## **Executive summary**

One of the major investors in Australian LNG, INPEX, has recently suggested that the country is quietly quitting the LNG business<sup>1</sup>. This is in the context of increasing government regulation, including the possibility of gas intended for LNG projects being diverted into the domestic market. The federal government has responded by reassuring major buyers that Australia will continue to be a reliable LNG supplier.

However, there are a number of fundamental challenges for the government in living up to its promise. First, Australian gas reserves are not being replaced, with some important legacy gas fields reaching the end of their lives. This includes both LNG and domestic gas fields. This leads to the possibility that shortfalls in the domestic market will have to be met by diversions from LNG projects that also face gas supply challenges. Second, the LNG projects are significant CO<sub>2</sub> emitters and many Australian gas fields, including those with the potential to backfill LNG, contain significant volumes of CO<sub>2</sub>. The new federal government has adopted more ambitious emissions reduction targets. Third, coal-fired generation is being closed faster than it can be replaced with renewables, increasing demand for gas in key periods such as winter and pushing up gas prices.

To meet domestic and export gas demand, more gas supply is needed and there are more than sufficient Contingent Resources to ensure this. However, many of the identified but undeveloped gas resources also contain varying percentages of CO<sub>2</sub>. New gas developments have to be net zero from day one, requiring carbon capture and storage (CCS) or carbon offsets. In particular, CCS will need to be developed quickly and at scale. Australia has massive CCS potential but developing it quickly and at scale is likely to require more supportive federal and state government policies.

Moreover, development of any new sources of domestic gas on the east coast is particularly challenged by activist litigation, lack of government support in some states and recent gas price caps. This makes it likely that gas will have to be diverted from east coast LNG projects, which themselves have their own gas supply challenges.

In the Northern Territory and Western Australia maintaining LNG production will require significant new gas development to backfill existing projects. Achieving this with zero net emissions will be a challenge, while gas from LNG may also need to be diverted to meet demand in the Northern Territory and Western Australia.

In short, LNG buyers who are concerned about Australia quietly quitting the LNG business are right to be concerned.

<sup>&</sup>lt;sup>1</sup> Ueda, T. (2023). 'Speech Parliament House Canberra 30 March 2023', https://www.au.emb-japan.go.jp/files/100483932.pdf



# 1. Introduction

It must be confusing for anyone outside Australia to understand what is happening when a major LNG investor says one of the world's largest LNG exporters is "quietly quitting" the LNG business. In 2022 Australia exported 82.0 million tonnes (Mt) of LNG<sup>2</sup> (valued at \$63 billion)<sup>3</sup>, setting a new record and making it one of the world's largest LNG exporters, similar to the 81.2 Mt exported by Qatar and just above the 79.1 Mt exported by the United States<sup>4</sup>. The United States and Qatar are both aggressively increasing their LNG capacity, not walking away.

The claim that Australia is quitting LNG was made by Mr. Takayuki Ueda, Chief Executive Officer of Japanese company INPEX and operator of the Ichthys LNG project in Darwin. He was speaking at Parliament House Canberra on 30 March<sup>5</sup>. Ichthys, the INPEX LNG project in Darwin, required a capital investment of over A\$60 billion (US\$40 billion) and represents the largest-ever overseas investment by a Japanese company. His comments were reinforced by the Japanese Ambassador, Mr. Shingo Yamagami, speaking at the same function. He said that Japan will still need Australian gas for the foreseeable future. He added that he "had every confidence his Aussie mates would remain a trusted and stable energy exporter moving forward"<sup>6</sup>. Underlying the importance of the issue to the Japanese government, both speeches were posted on the Japanese embassy website. In a later interview, the Ambassador said, "There is a staggering reliance by Japan on Australia when it comes to energy security. I have this magic number 764 – among Japan's imports 70 per cent of coal comes from Australia, 60 per cent of iron ore and 40 per cent of gas comes from Australia. But what happening (sic) in recent months created an increasing amount of concern on the part of Japanese gas companies and in the trade houses and steel companies."<sup>7</sup> This leaves little doubt that the Japanese government is concerned about Australia's reliability as an energy exporter.

It is not only the Japanese that have voiced concern. In an exceptional example of North Asian solidarity, the Chinese embassy in Canberra, also underlined the Japanese concerns saying, "It's a major issue involving both of us. Definitely we will look at this case with serious attitude. Apart from that, special evaluation is necessary"<sup>8</sup>.

These comments were prompted by the federal government's plans to intervene in local gas markets following the east coast energy crisis in June 2022 and forecasts of massive increases in east coast gas and electricity prices. The government has since toughened the Australian Domestic Gas Security Mechanism (ADGSM) giving it the power to limit LNG exports, albeit only as a measure of last resort<sup>9</sup>. The policy has not been triggered to date.

The comments by the Japanese Ambassador came notwithstanding attempts by the federal government to support the role of gas in the energy transition and to reassure Asian LNG buyers that their own energy security would not be jeopardised.

<sup>&</sup>lt;sup>2</sup> Department of Industry, Science and Resources (DISER) (2023). 'Resources and Energy Quartely: March 2023', https://www.industry.gov.au/sites/default/files/2023-04/resources-and-energy-quarterly-march-2023.pdf

<sup>&</sup>lt;sup>3</sup> Monetary sums quoted in this paper are in US dollars (US\$). Australian dollars are shown as A\$. At the time of writing in early June 2023 A\$1=US\$0.6740.

<sup>&</sup>lt;sup>4</sup> US Department of Energy (2023). 'LNG Monthly: February 2023', <u>https://www.energy.gov/sites/default/files/2023-03/LNG%20Monthly%20December%202022\_3.pdf</u>. Converted to Mt using 48.7 Bcf per Mt. Bloomberg estimates that Qatar exported 81.2 Mt in 2022. Stapczynski, S. (2023). 'US Surges to Top of LNG Exporter Ranks on Breakneck Growth',

https://www.bloomberg.com/news/articles/2023-01-03/us-surges-to-top-of-lng-exporter-ranks-on-breakneck-growth#xj4y7vzkg <sup>5</sup> Ueda, T. (2023). 'Speech Parliament House Canberra 30 March 2023', https://www.au.emb-japan.go.jp/files/100483932.pdf <sup>6</sup> Yamagami, S. (2023a). 'Speech Parliament House Canberra 30 March 2023', https://www.au.emb-japan.go.jp/files/100483927.pdf

<sup>&</sup>lt;sup>7</sup> Yamagami, S. (2023b). 'Australian 'energy supply risk' worries Japan: ambassador Shingo Yamagami',

https://www.theaustralian.com.au/nation/australian-energy-supply-risk-worries-japan-ambassador-shingo-

yamagami/newsstory/e3d3519e14e63f807632443e592e468b#:~:text=The%20outgoing%20and%20outspoken%20Japanese,Australia%20as%20an%20energy%20supplier.

<sup>&</sup>lt;sup>8</sup> Tillett, A. and Macdonald-Smith, A. (2023). 'China, Japan united on Australian gas export fears',

https://www.afr.com/politics/federal/china-japan-united-on-australian-gas-export-fears-20230331-p5cx2p

<sup>&</sup>lt;sup>9</sup> https://www.minister.industry.gov.au/ministers/king/media-releases/adgsm-extended-2030-safeguard-domestic-energy-supply



On 7 March, speaking of the energy transition, Prime Minister Anthony Albanese said, "gas in particular has a key role to play, as a flexible source of energy – providing peaking power today and continuing to provide firming and back-up power. Helping to smooth the transition to renewables, while guaranteeing energy security both for Australia and for our partners in the region<sup>10</sup>."

After visiting Perth in October 2022, Japanese Prime Minister Kishida said, "Prime Minister Albanese told me Australia intends to remain a reliable partner and a safe investment destination. We agreed to further bolster our cooperation in the areas of energy and natural resources,"<sup>11</sup>. The Resources Minister Madeleine King visited Japan in November to reinforce Australia's role as a stable and reliable investment destination and trading partner<sup>12</sup>. The Trade Minister, Don Farrell personally reassured Japanese and South Korean counterparts in October that Australia remains a reliable supplier of resources<sup>13</sup>. Later, in March, responding to the concerns of the Japanese, Mr Farrell brushed off the warnings and said the government's policies would have "zero impact on our relations" with Japan." It won't have any impact on our international reputation or our reliability or stability as a supplier of, among other things, gas", he is reported to have said<sup>14</sup>. In May Richard Marles, the Defence Minister, was reported to have reassured the Singapore Government about Australian gas supplies<sup>15</sup>.

What is the outlook for Australian LNG and are existing Asian customers right to be concerned? Unfortunately, the answer is yes. It will be challenging for the government to live up to its promises. A number of legacy LNG and domestic gas fields are mature and need to be replaced but there are significant challenges to investment in new gas developments. At the same time there is a continuing need for gas domestically to facilitate the energy transition from coal-fired electricity generation to back-up renewables. Investment in new gas developments is increasingly risky and the political reality is that with insufficient new gas development, any domestic shortfalls are likely to be met by diverting gas from LNG projects, at the expense of Asian gas buyers undertaking their own energy transitions.

Section 2 of this paper provides an overview of Australian LNG and its rapid growth from one project in 2005 to 10 projects today. Section 3 discusses the relationship between the LNG export projects and the domestic gas markets on the east and west coasts. The four projects in Western Australia are subject to domestic gas reservation policies but not the two Northern Territory projects or the three Queensland projects. The result has been that east coast gas prices are significantly higher than those in Western Australia and there have been concerns about possible future domestic supply shortages. Section 4 considers the outlook for Australian gas supply generally. The fundamental problem for future Australian LNG exports, domestic gas supplies and energy prices is that Australian gas reserves are not being replaced. Section 5 considers the challenge of greenhouse emissions to further gas development. Australian gas projects are significant contributors to greenhouse emissions but in future new projects must be net zero from day one. While there are increasing constraints on gas development, Section 6 discusses the increasing need for domestic peak gas to support the disorderly transition away from coal-fired electricity generation. This was evident in the east coast energy crisis in winter 2022, when coal generation outages sent gas demand and prices soaring. Section 7 discusses the response to the crisis by the new federal government, which introduced an east coast gas price cap

- <sup>11</sup> McKeith, S. (2022). 'Australia's Albanese, Japan's Kishida agree to strengthen security ties',
- https://www.reuters.com/world/asia-pacific/australias-albanese-japans-kishida-meet-defence-energy-talks-2022-10-22/ <sup>12</sup> King, M. (2022). 'Japan visit to strengthen Australian resources and investment ties',

<sup>&</sup>lt;sup>10</sup> Coorey, P. (2023). 'PM backs gas as key player in energy transition', https://www.afr.com/business-summit/gas-has-a-key-role-in-energy-transition-albanese-20230306-

p5cpok#:~:text=Anthony%20Albanese%20says%20gas%20must,by%20the%20COVID%2D19%20pandemic.

https://www.minister.industry.gov.au/ministers/king/media-releases/japan-visit-strengthen-australian-resources-and-investment-ties

<sup>&</sup>lt;sup>13</sup> Tillett A. (2022). 'Trade minister to calm Japan, Korea over energy exports', https://www.afr.com/politics/federal/trademinister-to-calm-japan-korea-over-energy-exports-20221007-p5bnzb

<sup>&</sup>lt;sup>14</sup> Chambers, G. and Malcolm, J. (2023). 'Australia's 'investment climate deteriorating', says Japanese gas giant',

https://www.theaustralian.com.au/nation/politics/australias-investment-climate-deteriorating-says-japanese-gas-giant/news-story/961d77560a63039a10570b326d3fd15c

<sup>&</sup>lt;sup>15</sup> Tillet, A. (2023). 'Marles reassures Singapore over gas supplies', https://www.afr.com/politics/federal/marles-reassuressingapore-over-gas-supplies-20230501-p5d4if



and tightened the policy to facilitate the diversion of gas from LNG projects to the domestic market, as well as increased taxation on offshore LNG projects. Section 8 concludes that in the context of increasing domestic gas demand to support the energy transition, declining legacy gas fields, and constraints on new gas development, Australia's record LNG exports in 2022 are likely to represent a peak, followed by a gradual decline.

# 2. Australian LNG overview

Australia has 10 operating LNG projects with a total capacity of 88.6 million tonnes per annum (Mtpa) (120 billion cubic metres (Bcm)), located in Western Australia, Queensland and the Northern Territory (Figure 1 and Table 1). The Pluto Train 2 project currently under construction will bring total capacity to 93.6 Mtpa (126 Bcm).

The projects are all joint ventures, with a predominance of major international companies. Chevron operates Gorgon and Wheatstone, Shell operates QCLNG and Prelude, INPEX operates Ichthys. Origin Energy and ConocoPhillips operate APLNG. Australian company Woodside operates the NWS and Pluto, and Santos operates GLNG and Darwin LNG. ExxonMobil, TotalEnergies, CNOOC, BP, MIMI, Sinopec, Petronas and Kogas are some of the other well-known joint venture partners.

# Darwin Australia Pacific LNG NORTHERN Queensland TERRITORY Curtis LNG OUEENSLAN WESTERN USTRALIA Gladstor LNG SOUTH AUSTRALIA NEW SOUTH WAIES VICTORIA **LEGEND** TASMANIA UNG project capacity (Mtpa) Total - SEMIpo Australian LNG Projects and Gas Basins ENERGYQUEST nd by Batt I IIII mapping.com.au © Copyright EnergyOu

#### Figure 1: Australian LNG projects and gas basins

Source: EnergyQuest



#### **Table 1: Australian LNG projects**

Project Name	Participants	State	Capacity (Mtpa)	Start date	Status
QCLNG (T1-T2)	Shell, CNOOC, EIG	Queensland	8.5	2015	Operational
APLNG (T1-T2)	ConocoPhillips, Origin Energy, Sinopec	Queensland	9	2015	Operational
GLNG (T1-T2)	Santos, Petronas, TotalEnergies, KOGAS	Queensland	8.6	2015	Operational
North West Shelf (T1-T5)	Woodside, BP, Chevron, Shell, MIMI	Western Australia	16.9	1989	Operational
Pluto (T1)	Woodside, Kansai Electric, Tokyo Gas	Western Australia	4.9	2012	Operational
Gorgon (T1-T3)	Chevron, Shell, ExxonMobil	Western Australia	15.6	2016	Operational
Wheatstone (T1- T2)	Chevron, KUFPEC, Woodside	Western Australia	8.9	2017	Operational
Prelude FLNG	Shell, INPEX, KOGAS, OPIC	Western Australia	3.6	2018	Operational
Darwin (T1)	Santos, SK E&S, INPEX, Eni, JERA, Tokyo Gas	Northern Territory	3.7	2006	Operational
Ichthys (T1-T2)	INPEX, TotalEnergies, CPC, Tokyo Gas, Kansai Electric, JERA, Toho Gas	Northern Territory	8.9	2018	Operational
Pluto (T2)	Woodside, Global Infrastructure Partners	Western Australia	5.0		Under construction, first cargo 2026
Total			93.6		

Source: EnergyQuest

The largest and oldest LNG project is the North West Shelf (NWS), which commenced production in 1989, predominantly supplying Japan but also with a ground-breaking contract with Chinese buyer CNOOC signed in 2004. The NWS was followed in 2006 by the Darwin LNG project, also supplying Japanese customers. These two projects were followed by a further eight projects that started construction around 2009 and commenced production between 2015 and 2018: Queensland Curtis LNG (QCLNG) and Gladstone LNG (GLNG) in 2015, Gorgon and Australia Pacific LNG (APLNG) in 2016, Wheatstone in 2017 and Ichthys and Prelude in 2018. Wood Mackenzie estimates that Australia's LNG boom of the 2010s saw over \$310 billion of international oil and gas capital spent across the development and early operation of nine new LNG infrastructure projects<sup>16</sup>. For 71 Mtpa of new capacity this works out at US\$4,366 per tonne per annum (tpa) of new capacity, making the projects some of the most expensive in the world<sup>17</sup>. At the same time this investment helped offset the impact of the global financial crisis on Australia as well as driving \$50 billion of annual export earnings from LNG from 2020 onwards. (LNG was Australia's third-largest export by value in 2021-22 after iron ore and coal<sup>18</sup>.)

<sup>&</sup>lt;sup>16</sup> Wood Mackenzie (2023). 'APPEA-LNG Taxation estimates and Review', https://www.appea.com.au/wp-

content/uploads/2023/04/23.04.12-APPEA-LNG-Taxation\_Report\_FINAL-FOR-PUBLICATION-3.pdf

<sup>&</sup>lt;sup>17</sup> Songhurst, B. (2014). 'LNG Plant Cost Escalation', OIES Paper NG 83 February 2014.

https://a9w7k6q9.stackpathcdn.com/wpcms/wp-content/uploads/2014/02/NG-83.pdf

<sup>&</sup>lt;sup>18</sup> https://www.dfat.gov.au/trade/trade-and-investment-data-information-and-publications/trade-statistics/trade-in-goods-and-services/australias-trade-goods-and-services-2021-22



The projects were all underpinned by long-term contracts with Asian buyers. In 2022 Japan was the largest buyer from Australia, taking 38% of deliveries, followed by China, South Korea and Taiwan. Altogether the four North Asian countries accounted for 91% of Australian deliveries in 2022 (Table 2).

	Share of	Market	
	deliveries	share	
Japan	38%	43%	
China	28%	34%	
South Korea	15%	25%	
Taiwan	10%	37%	

## Table 2: Australian LNG deliveries 2022

Source: EnergyQuest EnergyQuarterly March 2023<sup>19</sup>

Australia was also the largest LNG supplier in each of these markets, with market shares of 25% in South Korea, 34% in China, 37% in Taiwan and 43% in Japan. It is not surprising that these countries are worried about the future reliability of Australian LNG.

Around 75% of shipments are under long-term contracts, with prices mostly indexed to oil prices (the Japanese Customs Cleared oil import price or Brent).

Australian LNG projects have a good reliability record, notwithstanding some initial teething problems with Gorgon and the Prelude floating LNG project. In 2022 the projects operated at 93% of nameplate capacity.

Western Australia dominates Australian LNG production, accounting for 60% of shipments in 2022, followed by Queensland with 29% and the Northern Territory with 11%. Both Western Australia and Queensland are globally significant LNG exporters in their own right.

The Western Australian and Northern Territory projects are based on conventional offshore gas fields while the Queensland projects are based on onshore coal seam gas (CSG, also known as coal bed methane), with thousands of gas wells. They are the only LNG projects in the world to be based on CSG. Unlike US shale gas and west coast LNG projects, Queensland CSG does not have high-value associated liquids (condensate and LPG), which improves the economics of those other projects. At the time the projects were sanctioned there was great optimism about the size and quality of the CSG resource, best suited to large-scale LNG development for the high-price export market.

There was also great optimism about the potential for shale gas development. A 2013 assessment of world shale gas resources, commissioned by the US Energy Information Administration rated Australia as seventh globally for shale gas resources, with technically recoverable shale gas resources of 93 trillion cubic feet (98,100 petajoules (PJ) or 2,620 Bcm) in the Cooper Basin spread across South Australia and Queensland<sup>2021</sup>.

However, the Queensland projects also entailed substantial risks: building three LNG projects using a largely untried onshore resource in populated areas, in a domestic market spread across four powerful states, each with its own resource development and energy policies. Offshore LNG projects are typically sanctioned on the basis of Proved Reserves (1P 90% likely). The CSG projects were sanctioned on Proved and Probable Reserves (2P 50% likely), with an expectation that Queensland reserves would increase and that they would be added to by onshore CSG development in NSW and shale gas development in South Australia and Queensland. Instead, there have been reserve write-downs in Queensland, and CSG and shale gas reserves have failed to materialise in other states. Onshore gas

<sup>&</sup>lt;sup>19</sup> EnergyQuest (2023). 'EnergyQuarterly March 2023: The Government takes over',

https://www.energyquest.com.au/energyquarterly-march-2023-the-government-takes-over/

<sup>&</sup>lt;sup>20</sup> https://www.eia.gov/analysis/studies/worldshalegas/pdf/overview.pdf

<sup>&</sup>lt;sup>21</sup> 1 petajoule (PJ) = 26.71 MMcm



development in NSW and Victoria was effectively banned following anti-gas campaigns by farmers and activists. Shale gas was tried in the Cooper Basin, even attracting global oil and gas major Chevron. However, the gas proved to be dry, lacking the higher-value liquid hydrocarbons present in US shale gas. It was also high in CO<sub>2</sub> and difficult to fracture stimulate. As a result, it has transpired that the east coast gas faces potential domestic gas shortages, requiring diversion of gas from LNG projects to the domestic market<sup>22</sup>. These risks were flagged in previous OIES reports<sup>23</sup>.





Source: EnergyQuest (2023)

## 3. LNG and domestic gas markets

In addition to producing LNG, Australia also has a significant domestic gas market. Figure 2 shows Australian gas production, exports and domestic consumption in 2022, together with major gas pipelines. LNG exports are almost five times the size of the domestic gas market. Most of Australia's gas lies on the west coast but most of the population lives on the east coast, which also has the largest domestic gas market. (There have been a number of attempts to justify a west-east gas pipeline but the distances are too great and the relatively small east coast gas demand at 559 PJ is too scattered for a pipeline to be commercially viable.)

<sup>&</sup>lt;sup>22</sup> https://aemo.com.au/-/media/files/gas/national\_planning\_and\_forecasting/gsoo/2023/2023-gas-statement-of-opportunities.pdf?la=en

 <sup>&</sup>lt;sup>23</sup> Ledesma, D., Henderson, J. and Palmer, N. (2014), 'The Future of Australian LNG Exports', OIES Paper NG 90; Ledesma, D. and Drahos, N. (2018), 'Prices and crisis: LNG and Australia's East Coast gas market', OIES Energy Insight: 30. Drahos, N. (2021), 'Australia's gas trilemma: prices, exports and emissions'. OIES Energy Insight 100



Nearly all of the gas production in Western Australia is from the prolific offshore Carnarvon Basin, the home of four major LNG plants plus domestic gas plants. Domestic gas is used mainly for power generation and to meet industrial demand. In Western Australia LNG projects are required to supply the Western Australia domestic market (401 PJ in 2022) as well as export demand. They supplied 38% of the domestic market in 2022. Western Australia has a long-standing domestic gas reservation policy requiring LNG projects to reserve 15% of their LNG production for the domestic market<sup>24</sup>. This policy is accepted by LNG producers as a cost of doing business. It has not impeded LNG development or even onshore gas exploration. Following the surge in international gas prices, Western Australia now has some of the lowest wholesale domestic gas prices in the OECD. Contract gas prices are currently below \$5.00/MMBtu.

On the east coast the largest producing basin is now the onshore Surat-Bowen Basin in Queensland, based on CSG and supplying three LNG projects as well as east coast domestic demand. Most of the LNG is under long-term contracts to Asian buyers, particularly Chinese buyers. Historically domestic gas for the southern states of New South Wales, Victoria and South Australia was supplied from the onshore Cooper Basin and fields offshore Victoria. These fields have now been in production for over 50 years and are in the decline phase.

Figure 3 shows east coast gas production by source in 2012, as CSG production for the new LNG projects was beginning to ramp up, and in 2022 when the LNG projects were all fully operational.



Figure 3: Australian east coast gas production, 2012 and 2022 (PJ)

Source: EnergyQuest

East coast gas production is now dominated by CSG, mostly for export, with conventional gas production already declining from offshore Victoria and the Cooper Basin and expected to decline further.

ExxonMobil, operator of the Gippsland Basin offshore Victoria has warned that the number of producing wells will decline from 68 in 2022 to 36 by next winter.<sup>25</sup> In 2022 the Gippsland Basin supplied more than 70% of south-east Australia's domestic gas demand.

<sup>&</sup>lt;sup>24</sup> https://www.wa.gov.au/government/publications/wa-domestic-gas-policy

<sup>&</sup>lt;sup>25</sup> https://www.afr.com/companies/energy/exxon-warns-of-dwindling-bass-strait-gas-20230322-p5cuce



As in the United States, the east coast LNG projects are integrated with the domestic gas market. They can both draw on and contribute to domestic gas, typically drawing on gas from fields in Victoria and South Australia in summer and supplying gas to the southern states in winter. Overall, in 2022 Queensland LNG producers supplied around 4% of their LNG production to the domestic market.

Unlike Western Australia, there is no explicit domestic gas reservation policy on the east coast. The federal government Productivity Commission considered a domestic gas reservation scheme in 2015 but recommended against it on the grounds that it would discourage new development<sup>26</sup>. There was considerable optimism about the potential for increased east coast gas supply. However, there were also obvious risks of possible shortages in the east coast domestic gas market<sup>27</sup>.

In 2017 the federal government tasked the Australian Competition and Consumer Commission (ACCC) with an ongoing Gas Inquiry to monitor domestic gas contracting, prices and competition issues<sup>28</sup>. The government also developed the Australian Domestic Gas Supply Security Mechanism (ADGSM), which was first introduced on 1 July 2017, to allow the government to restrict LNG exports as a measure of last resort in the event of a domestic gas supply shortfall. The ADGSM (which has since been strengthened) has never been activated but the threat of it being triggered is an incentive to LNG producers not to ignore the domestic gas but with increasing political pressure to also make provision for the domestic market.) The ADGSM was effectively an attempt by the federal government to implement a retrospective reservation policy without overriding long-term LNG export contracts with major trading partners.

There has been an element of domestic gas reservation in Queensland where the government subsequently introduced provisions to enable new acreage releases to be earmarked for domestic gas production. This came years after the LNG projects were approved.





Source: Australian Bureau of Statistics

<sup>&</sup>lt;sup>26</sup> Productivity Commission (2015). 'Examining Barriers to More Efficient Gas Markets',

https://www.pc.gov.au/research/completed/gas-markets

<sup>&</sup>lt;sup>27</sup> EnergyQuest (2013). 'Australian Coal Seam Gas 2013: All Aboard the LNG Train'. Bethune, G. (2017), 'Where is the east coast domgas development boom?', <u>https://www.energyquest.com.au/where-is-the-east-coast-domgas-development-boom/</u>. Bethune, G. (2018), 'Australian East Coast Gas Pricing', 27<sup>th</sup> World Gas Conference, Washington.

<sup>&</sup>lt;sup>28</sup> ACCC Gas Inquiry. https://www.accc.gov.au/about-us/publications/serial-publications/gas-inquiry-2017-30-reports



The end result of the contrasting developments on the west and east coasts is that east coast gas prices are significantly higher than in Western Australia (Figure 4)<sup>29</sup>. Even in the midst of the pandemic at the end of 2020, east coast spot prices averaged \$4.90/MMBtu, nearly twice the NWS domestic gas price of \$2.60/MMBtu. Prices are now higher on both coasts. As of the December quarter 2022, Santos average east coast realised gas price was \$8.35/MMBtu and its west coast average was \$4.70/MMBtu.

## 4. Australian gas reserves not being replaced

The fundamental problem for future Australian LNG exports, domestic gas supplies and gas prices is that Australia's gas reserves are not being replaced, either by the development of Contingent Resources or by exploration. Contingent resources (2C) are gas volumes that have been identified but are not yet capable of development for commercial or technical reasons.

Since March 2018 Australian Proved and Probable (2P) gas reserves have fallen by 11%, from 114,481 PJ (3,057 bcm) to 101,869 PJ (2,721 bcm)<sup>30</sup>. While Australia experienced an LNG development boom in the 2010s, important legacy LNG and domestic fields are now in the decline phase. Maintaining LNG production and meeting domestic demand requires investment in new development, which is not occurring on the scale needed.

Figure 5 shows the current estimates of 2P reserves and 2C contingent resources. As at March 2023, 2P reserves were just over 100,000 PJ and 2C resources were also close to 100,000 PJ.



## Figure 5: Natural gas reserves and contingent resources March 2023 (PJ)

#### Source: EnergyQuest 2023

<sup>&</sup>lt;sup>29</sup> For a country where gas prices are an important policy and political issue, Australia has surprisingly limited official statistics on either wholesale or retail gas prices. These inadequacies have been noted in the recent IEA Review of Australian Energy Policy (<u>https://www.iea.org/reports/australia-2023</u>).

<sup>&</sup>lt;sup>30</sup> EnergyQuest EnergyQuarterly reports, March 2018 and March 2023.



Although Australia is often said to have abundant gas and is one of the world's largest LNG producers, it only ranks twelfth in terms of global rankings of reserves as estimated by BP<sup>31</sup>. However, with 100,000 PJ of 2C resources and sufficient investment Australia should be able to maintain or even increase LNG exports while also supplying adequate domestic gas for the energy transition. Australia also has significant remaining exploration potential.

However, Australian energy companies, like their global peers, are slashing their exploration budgets, sacking their explorers and shifting their investment to renewables or handing money back to the shareholders. This is consistent with global messaging about the limited long-term future of natural gas. For example, G7 energy ministers meeting in Japan in April, only gave heavily qualified support to natural gas and LNG development: "recognizing the primary need to accelerate the clean energy transition through energy savings and gas demand reduction, investment in the gas sector can be appropriate to help address potential market shortfalls provoked by the crisis, subject to clearly defined national circumstances, and if implemented in a manner consistent with our climate objectives and without creating lock-in effects, for example by ensuring that projects are integrated into national strategies for the development of low-carbon and renewable hydrogen"<sup>32</sup>. The full G7 expressed similar sentiments at their meeting in May <sup>33</sup>. These messages are not encouraging for any company contemplating long-term investments in gas projects.

In Australia oil and gas exploration is now at the lowest level in two decades.





Sources: Australian Bureau of Statistics, US Energy Information Administration

Figure 6 shows Australian petroleum exploration expenditure back to 2000. Current exploration spending is about the same now as it was 20 years ago. Until 2016 exploration spending followed oil prices but over the last five or six years, oil prices have soared, but exploration has been in the doldrums.

<sup>&</sup>lt;sup>31</sup> BP Statistical Review of World Energy June 2022. https://www.bp.com/content/dam/bp/business-

sites/en/global/corporate/pdfs/energy-economics/statistical-review/bp-stats-review-2022-full-report.pdf

<sup>&</sup>lt;sup>32</sup> https://www.meti.go.jp/press/2023/04/20230417004/20230417004-1.pdf

<sup>&</sup>lt;sup>33</sup> https://www.whitehouse.gov/briefing-room/statements-releases/2023/05/20/g7-hiroshima-leaders-communique/



Without additional discoveries and investment Australian LNG exports are likely to decline, both due to natural decline in important legacy LNG fields and increased diversion to meet domestic demand as current domestic fields decline. In 2022 Australian 2P gas reserves only grew by 1,450 PJ, well below production of 5,500 PJ per annum<sup>34</sup>. So far as gas supply goes, Australia is quietly living off past discoveries.

Table 3 shows current Australian gas reserves, LNG and domestic gas production and reserve life by gas basin as at March 2023.

Out of the 23 Australian producing gas projects, nine have reserves lives of 10 years or less. This includes a number of important west coast fields that also have short remaining reserve lives.

	2P Reserves March 2023	LNG Production	LNG Production	Domestic Production	Total production	Reserve life
	DI.	2022	2022	2022	2022	Veerre
Northern Australia	РJ	IVIT	PJ	PJ	PJ	rears
Amadeus Basin	220	0	0	15	15	15
Browse Basin	220	0	0	15	15	15
Ichthys I NG	11619	7,870	436	0	436	27
Prelude LNG	3536	1.362	75	0	75	47
Bonaparte Basin				-		
Blacktip	191	0	0	19	19	10
Bayu-Undan Darwin LNG	0	1.346	75	0	75	0
Barossa LNG	4096	0	0	0	0	
Western Australia						
Carnarvon Basin						
Gorgon LNG	21985	16.769	930	99	1029	21
Wheatstone-Julimar-Brunello LNG	6163	9.447	524	62	586	11
NWS LNG	4593	14.873	824	26	850	5
Pluto LNG	1924	6.157	341	7	348	6
Scarborough	12149	0	0	0	0	
John Brookes	624	0	0	72	72	9
Macedon	466	0	0	70	70	7
Reindeer	84	0	0	45	45	2
Perth Basin	1624	0	0	17	17	96
Total western and northern Australia	69274	57.82	3205	432	3637	19
Eastern and southern Australia						
Cooper Basin	1024	0	0	80	80	13
Gippsland Basin	1687	0	0	310	310	5
Otway Basin	600	0	0	48	48	13
Bass Basin	24	0	0	5	5	5
Surat-Bowen Conventional	310	0	0	8	8	39
Surat-Bowen LNG	26891	23.226	1373	55	1428	19
Other Surat-Bowen CSG	2051	0	0	43	43	48
NSW	7	0	0	1	1	5
Total eastern and southern Australia	32594	23	1373	550	1923	17
Total	101868	81.1	4578	982	5560	18

#### Table 3: Australian 2P remaining gas reserves, production and reserve life

Source: EnergyQuest EnergyQuarterly March 2023

#### **4.1 Northern Territory**

In the Northern Territory (NT), there are two LNG projects, Darwin and Ichthys, plus the Amadeus and Blacktip fields which supply domestic gas for power generation and are linked by pipeline to North Queensland and hence the east coast gas market. For many years the NT was over-contracted to the Eni-operated Blacktip field and able to supply excess gas to Queensland. However, in 2022 Blacktip

<sup>&</sup>lt;sup>34</sup> EnergyQuest (2023). 'EnergyQuarterly March 2023: The Government takes over',

https://www.energyquest.com.au/energyquarterly-march-2023-the-government-takes-over/



production began to decline, from 30 PJ the year before to 19 PJ, cutting supply to Queensland from 19 PJ to 8 P<sup>35</sup>. There are already links between the Ichthys and Darwin LNG plants and the NT domestic system, to which there have already been emergency gas diversions<sup>36</sup>. In the event of Blacktip production continuing to fall and/or shortages on the east coast it is possible that the LNG plants could be required to divert more gas to the domestic market. Replacing Blacktip completely with LNG diversions could reduce exports by around 0.5 Mtpa. This scenario may have been one of the motivations for the public comments by INPEX.

The Bayu-Undan field (located in Timor-Leste waters), which has fed the Darwin LNG plant, is expected to cease production in mid-2023 and is being repurposed by Santos for carbon capture and storage (CCS). The resumption of production from Darwin LNG relies on the development of the Barossa gas field, which has significant reservoir  $CO_2$  (around  $18\%^{37}$ ), which Santos plans to mitigate through Bayu-Undan CCS. Under the new Safeguard Mechanism Barossa could be required to have zero net emissions from the start of production. This is likely to require use of carbon offsets until Bayu-Undan CCS is operational.

Development is being delayed by activist litigation. In its Q1 report, the operator Santos reported that the Barossa project was 56% complete but drilling activities have been suspended. The original environmental approval was overturned as a result of litigation by activists, including indigenous groups. Resumption of drilling is pending re-submission and approval of the environmental plan<sup>38</sup>. It seems unlikely that these actions would place the entire project in jeopardy, but it depends on the regulator and any further court actions. The project joint venturers are Santos (50%), South Korean company SK E&S (32.5%) and Japanese company JERA (12.5%). Santos has a 10 year LNG supply contract with Japanese company Mitsubishi for the supply of 1.5 Mtpa of LNG from the Barossa project.

The NT also has an onshore basin, Beetaloo, with a Contingent Resource of over 7,000 PJ, with potential for LNG, NT industrial development and/or east coast domestic supply. This is a shale gas play requiring fracture stimulation. The federal Department of Industry is on record as saying it has "the potential to rival the world's biggest and best gas resources"<sup>39</sup>. However, the Basin is still in the early stages of appraisal. Drilling is progressing although one major company, Origin Energy, has recently divested its interest. The Basin is also remote and expensive to explore and develop. The NT government has just approved development, following a scientific inquiry held in 2018 which concluded that risks could be managed. Reservoir CO<sub>2</sub> is estimated to be a relatively low 1-3%<sup>40</sup>. A recent CSIRO research study<sup>41</sup> has addressed greenhouse emissions and concluded, on conservative assumptions, that "from an engineering perspective, the majority of GHG emissions can be mitigated or physically abated with options available in Australia for the four scenarios of 365 PJ/year production"<sup>42</sup>. However, this is unlikely to satisfy the long-running, well-resourced national campaign aiming to prevent development.

p5cw66#:~:text=Tens%20of%20billions%20of%20dollars,industry%20vital%20for%20energy%20security. <sup>38</sup> https://www.santos.com/news/2023-first-quarter-report/

<sup>&</sup>lt;sup>35</sup> EnergyQuest (2023). 'EnergyQuarterly March 2023: The Government takes over',

https://www.energyquest.com.au/energyquarterly-march-2023-the-government-takes-over/

<sup>&</sup>lt;sup>36</sup> <u>https://www.energynewsbulletin.net/maintenance-shutdowns/news/1453062/santos-to-supply-nt-and-east-coast-through-Ing-project</u>. In the case of Santos, the Darwin LNG plant is close to ceasing LNG exports due to the decline in gas supply from the Bayu-Undan field. However, while there will not be sufficient gas for LNG cargoes there is still likely to be some gas available for the domestic market. The Barossa gas development is intended to backfill Darwin LNG.

<sup>&</sup>lt;sup>37</sup> https://www.afr.com/companies/energy/gas-projects-on-the-line-as-safeguard-belt-tightens-20230329-

<sup>&</sup>lt;sup>39</sup> https://www.industry.gov.au/publications/beetaloo-strategic-basin-plan/beetaloo-strategic-basin-plan

<sup>&</sup>lt;sup>40</sup> https://www.afr.com/companies/energy/gas-projects-on-the-line-as-safeguard-belt-tightens-20230329-

p5cw66#::=Tens%20of%20billions%20of%20dollars, industry%20vital%20for%20energy%20security.

<sup>&</sup>lt;sup>41</sup> Timothy M Baynes, Grant, T., Marcos-Martinez, R., West, J. (2022). 'Offsets for Life Cycle Australian Greenhouse Gas Emissions of Onshore Shale Gas in the Northern Territory, CSIRO, Australia. https://gisera.csiro.au/wp-

content/uploads/2023/02/GISERA\_G7\_Final\_report\_final-20230207.pdf

<sup>&</sup>lt;sup>42</sup> 365 PJ/year is itself an ambitious production assumption. EnergyQuest assumes 50 PJ/year.



## 4.2 Western Australia

In Western Australia (WA), two LNG projects and the three stand-alone domestic gas projects all have short reserves lives. The NWS and Pluto LNG projects only have remaining reserves lives of five and six years respectively. In 2022 the two projects delivered 10.0 Mt of LNG to Japan, 8.7 Mt to China and 2.5 Mt to Korea. Pluto began supplying feedstock to the NWS in 2022 to maintain the plant's capacity utilisation. In 2022 the NWS signed its first third-party gas processing agreement, and in 2021 the WA government agreed to a limited supply of gas to the NWS from the onshore Waitsia gas field in the Perth Basin, equivalent to 3.75 Mt of LNG. The Perth Basin is one basin where there is active exploration and development. However, it is unlikely that the WA government would agree to further onshore domestic gas going to LNG when the three domestic gas fields – John Brookes, Macedon and Reindeer – also have short reserves lives.

Woodside and its NWS partners are actively working on securing further third-party gas to maintain NWS production and in December 2022 signed a deal with Western Gas for 2-3 Mtpa from 2027.

Woodside is also developing the Scarborough/Pluto T2 project, which will have production of 8 Mtpa. By itself, this will be insufficient to replace the current 21 Mtpa of production from the NWS and Pluto.

Interestingly, the energy buyers with contracts for Scarborough are not Chinese, Japanese or Korean but are the European companies RWE and Uniper and the Indonesian company Pertamina. Scarborough will also produce domestic gas. It has relatively low CO<sub>2</sub> at around 0.5%.

Looking further out, Woodside is re-evaluating the potential development of the Browse LNG project, based on the 11,390 PJ 2C resource in the Brecknock, Calliance and Torosa gas fields in the Browse Basin. This will be the third development proposal for the fields. The first proposal, which involved an onshore LNG plant, was ultimately rejected based on cost and environmental opposition. The second proposal was for a floating LNG plant but this appears to have been dropped following the difficulties with the Shell Prelude project. The current proposal is to feed the gas to the NWS at Karratha via a 900 km pipeline<sup>43</sup> to produce 11.4 Mtpa of LNG plus domestic gas. CCS is being considered for the management of greenhouse emissions, with around 8-12% CO<sub>2</sub>. As shown by the two earlier failed attempts at development, Browse is a challenging project. Shell has recently divested its share to BP. One of the challenges will be aligning the Browse joint venture (Woodside, BP, PetroChina and MIMI) with the NWS joint venture (Woodside, BP, Chevron, MIMI and Shell). Any development is also sure to spark strong environmental opposition.

Even if it is possible to maintain Carnarvon Basin LNG production through some combination of Waitsia, Scarborough and ultimately Browse, there is also the challenge of meeting domestic gas demand. The legacy domestic gas fields in WA, John Brookes, Macedon and Reindeer, now have relatively short remaining reserves lives. The bright spot for domestic gas is the Perth Basin, where there have been exciting initial discoveries but also some subsequent disappointments.

In its latest WA Gas Statement of Opportunities<sup>44</sup> the Australian Energy Market Operator (AEMO) says the WA domestic gas market is facing a tight supply-demand balance between 2023 and 2029. From 2030 onwards, the gas market is forecast to move into a larger deficit, with shortfalls of over 200 terajoules per day (TJ/d) between 2030 to 2032 (over 16% of demand each year). This is driven by planned coal generation retirements increasing the need for gas generation and a decline in production from existing gas fields. Domestic gas from the development of Scarborough is earmarked for a new urea project.

Overall, adding together potential NWS decline by 2030 (17 Mt) and potential additional LNG diversion to the domestic market (2 Mt) less Pluto T2 development (5 Mt) and recent third-party gas (3 Mt) suggests that WA LNG exports could be around 11 Mt lower by 2030, 22% below the 49 Mt exported in 2022. This decline would be reduced to the extent that the NWS is able to secure further, substantial third-party gas supplies.

<sup>43</sup> https://www.woodside.com/what-we-do/developments-and-exploration/browse

<sup>&</sup>lt;sup>44</sup> https://aemo.com.au/en/energy-systems/gas/gas-forecasting-and-planning/wa-gas-statement-of-opportunities-wa-gsoo



## 4.3 East coast

The east coast has similar challenges in both LNG and domestic gas. The nominal remaining reserve life of the LNG projects is 19 years. However large volumes of CSG 2P reserves were booked despite having little drilling data and almost no production performance data. Developed remaining 2P is only 14,387 PJ, giving a nominal remaining reserves life of 8 years based on current production levels. CSG fields require continuous drilling of wells, with the performance of new wells being poorer than that of original wells, as development moves on from the "sweet spots". EnergyQuest expects LNG production to begin to decline from the early 2030s<sup>45</sup>. LNG buyers from Gladstone will need to seek gas from alternative sources. The EnergyQuest forecast assumes that any east coast domestic supply gap is met from LNG imports. If this does not eventuate, there will need to be substantial diversions to the domestic market under the ADGSM, with an earlier decline in LNG exports.

The forecasts for east coast domestic gas supply and demand are increasingly dire. In its January 2023 Gas Inquiry Report<sup>46</sup> the Australian Competition and Consumer Commission (ACCC) said, "Avoiding a supply shortfall in 2023 will rely on LNG producers supplying sufficient gas into the domestic market". This problem has subsequently been avoided for 2023 but without expansion in production, the ACCC anticipates there will be gas shortfalls from 2027 arising from export and domestic demand. Similarly, AEMO's 2023 Gas Statement of Opportunities for the east coast<sup>47</sup> warns (page 67) that:

- "Domestic supply gaps are at risk of emerging from 2023, if Queensland LNG exports are greater than advised contract levels, with a supply gap of up to 33 PJ."
- "From 2026, without anticipated supplies being developed, Queensland LNG exporters must divert gas contracted for export to the domestic market to maintain domestic adequacy. Domestic supply gaps would result if the gas required by southern customers is instead exported to meet advised export contract commitments."
- "From 2027, even with the development of anticipated supplies, and with Queensland LNG exporters diverting the maximum amount of gas possible (limited by pipeline capacity) to southern customers, supply gaps affecting southern regions are forecast to emerge."

These conclusions are broadly similar to independent forecasts by EnergyQuest<sup>48</sup>.

The biggest east coast conventional gas basin is the Gippsland Basin, with a remaining reserve life of only around five years. The basin is the major source of gas supply to New South Wales as well as Victoria.

A number of attempts have been made to alleviate the looming east coast supply deficit. NSW, which currently produces no gas, has a significant 2C resource of 2,264 PJ in the Narrabri field in the Gunnedah Basin in northern NSW. This could supply half of NSW gas demand. However, the operator Santos has been trying to develop the field for a decade, without any real support from the NSW Government and with continual opposition from activists<sup>49</sup>. The project is yet to receive final regulatory approval. The field has CO<sub>2</sub> concentration of up to 10% and under the tightened Safeguard Mechanism will need to have zero net emissions from day one. Reflecting the tortuous process for getting regulatory approval, the Santos CEO has said that the only effort he is putting into this project is getting approvals. He will not spend one dollar developing it until he receives regulatory approvals<sup>50</sup>.

opportunities.pdf?la=en

<sup>&</sup>lt;sup>45</sup> EnergyQuest (2022), East Coast Domestic Gas Outlook 2022. https://www.energyquest.com.au/new-east-coast-gas-outlook-2022/

 <sup>&</sup>lt;sup>46</sup> https://www.accc.gov.au/system/files/Gas%20Inquiry%20-%20January%202023%20interim%20report%20-%20FINAL\_0.pdf
 <sup>47</sup> https://aemo.com.au/-/media/files/gas/national\_planning\_and\_forecasting/gsoo/2023/2023-gas-statement-of-

<sup>&</sup>lt;sup>48</sup> EnergyQuest (2022), East Coast Domestic Gas Outlook 2022. https://www.energyquest.com.au/new-east-coast-gas-outlook-2022/

<sup>&</sup>lt;sup>49</sup> Bethune, G. (2015), 'Challenges in Developing Unconventional Gas', 26<sup>th</sup> World Gas Conference, Paris.

<sup>&</sup>lt;sup>50</sup> Chanticleer (2023), 'Behind the scenes at Australia's biggest investor conference'. https://www.afr.com/chanticleer/behind-the-scenes-at-australia-s-biggest-investor-conference-20230503-p5d5bz



There have also been a number of LNG import terminals proposed for Victoria, NSW and South Australia. These could transport LNG from long distance gas supplies including the west coast and NT fields. Australian company AGL spent over \$70 million on a proposed project for Victoria only to have it rejected by the Victorian Government on environmental grounds. A second project proposed by Viva Energy has been required by the Minister to effectively redo its environmental impact statement, despite it being on an existing operating refinery site. There is no sign of support for LNG import terminals from the Victorian government, even though Victoria has the largest Australian gas demand swing for residential heating. The prospects for import terminals have also been adversely affected by the rise in global LNG prices together and increased federal government intervention in gas markets.

The Victorian Government is encouraging gas consumers to convert to electricity<sup>51</sup>. In the ACT households and businesses will not be able to install a gas connection from 2024<sup>52</sup>. However, these policies are intended to facilitate the transition to net zero over many years rather than to avert a pending gas supply shortage.

In these circumstances it seems inevitable that Queensland LNG producers will be required to divert increasing volumes of gas to southern markets, particularly in winter, reducing LNG exports. This would occur under the ADGSM<sup>53</sup>. This is described as a measure of last resort, only used if market-based solutions and other regulatory interventions fail to provide sufficient gas to Australian consumers. It has not been triggered for 2023. The policy guidelines recognise the need to protect long-term foundation contracts and to consider the impact on Australia's reputation as a reliable trade and investment partner. However, the interests of Australian consumers (voters) take precedence.

In the absence of LNG import terminals, gas diverted to the domestic market by the early 2030s could be the equivalent of half to one LNG train, around 2-4 Mt, down by 10-20% on current export levels.

## 5. Gas development and emissions

Much, but not all, of the opposition to gas development is driven by the contribution of natural gas to greenhouse emissions. Reducing greenhouse emissions from the industry is mission critical for further gas development.

Table 4 shows the Scope 1 emissions from selected Australian gas projects (mainly LNG although the domestic Moomba and Longford plants are also significant emitters). It also shows Scope 1 emissions for major producers of gas and oil. The project emissions are for 2020-21 and the company emissions are for 2021-22. While the emissions from the consumption of natural gas are lower than from coal, the production of gas and LNG also produces significant emissions Many Australian conventional gas reservoirs (but not CSG) contain CO<sub>2</sub>, which has historically been vented into the atmosphere. In addition, gas processing for domestic use or LNG requires energy, which further produces greenhouse emissions. The Queensland LNG projects also use grid power, generating Scope 2 emissions in addition to their Scope 1 emissions<sup>54</sup>.

According to Australia's Emissions Projections 2022<sup>55</sup>, Australian LNG facilities produced 36 Mt CO<sub>2</sub>e of Scope 1 emissions in 2020, 6 Mt from on-site electricity production, 18 Mt from energy production and 12 Mt from fugitive emissions. A 2021 study by the CSIRO estimated that Scope 1 emissions in 2019-20 from LNG were approximately 37.5 Mt and Scope 2 emissions were approximately 4.2 Mt CO<sub>2</sub>e.<sup>56</sup> Total Australian emissions in 2019-20 were 513.5 Mt CO<sub>2</sub>e, of which Scope 1 LNG emissions represented 7.3%.

<sup>&</sup>lt;sup>51</sup> https://www.energy.vic.gov.au/renewable-energy/victorias-gas-substitution-roadmap

<sup>&</sup>lt;sup>52</sup> https://www.abc.net.au/news/2022-08-04/act-no-new-gas-connections-from-2023-new-homes/101299552

<sup>&</sup>lt;sup>53</sup> https://www.industry.gov.au/mining-oil-and-gas/oil-and-gas/securing-australian-domestic-gas-supply

<sup>&</sup>lt;sup>54</sup>Scope 1 emissions are physically direct emissions controlled by a company, for example fugitive emissions from a gas plant. Scope 2 emissions are indirect emissions produced to generate the electricity purchased for an LNG plant.

<sup>&</sup>lt;sup>55</sup> https://www.dcceew.gov.au/sites/default/files/documents/australias-emissions-projections-2022.pdf

<sup>&</sup>lt;sup>56</sup> Heath, C. and Ong, C. (2021). 'Greenhouse gas emissions from the liquified natural gas industry in Australia'. CSIRO, Australia.



Gas project	Scope 1 emissions Mt CO2e	Company	Scope 1 emissions Mt CO2e
North West Shelf	6.8	Chevron	12.3
Ichthys	6.4	Woodside	9.0
Gorgon	5.5	Santos	7.3
Wheatstone	4.0	INPEX	6.7
QCLNG	2.7	QGC	2.8
Moomba plant	2.4	Conoco	2.1
APLNG facility	2.1	Shell	2.0
Pluto	1.9	Exxon	1.9
GLNG plant	1.7	Total	44.1
Darwin LNG	1.6		
Longford	1.6		
Prelude	1.5		
Total	38.2		

# Table 4: Selected gas projects and company Scope 1 emissions (Mt CO2e)

Source: Clean Energy Regulator

Virtually all Australian gas producers have committed to achieving net zero by 2050, by reducing emissions from their existing operations and investing in cleaner alternatives to fossil fuels.

CCS is critical in achieving the net zero target. Australia currently has one operating CCS project, Gorgon. The Santos Moomba CCS project has reached a final investment decision and there are another 16 projects under consideration<sup>57</sup>.

As shown in Table 4, Chevron is the largest emitter among oil and gas companies in Australia as the operator of both the Gorgon and Wheatstone LNG projects and a participant in the NWS. The Gorgon project is the world's largest CCS project. Injection was significantly delayed but commenced in August 2019 and by 31 January totalled 7.5 Mt CO<sub>2</sub>e. The project has injection capacity of 4 Mtpa of CO<sub>2</sub> but is only running at around one-third of that rate.<sup>58</sup> The Australian emissions projections assume that the project will capture 3.4 Mtpa CO<sub>2</sub>e. Neither Wheatstone nor the NWS currently have CCS capacity.

The INPEX Ichthys project is another major emitter. In his Canberra speech Mr Ueda noted that INPEX has committed to net-zero carbon emissions by 2050, with an interim goal of achieving a 30% or more reduction in carbon intensity over 2019 levels by 2030. CCS is fundamental to achieving net zero emissions for the company. INPEX is leading a prospective CCS development with joint venture participants Woodside Energy and TotalEnergies, the Bonaparte CCS Assessment Project. They have been awarded a greenhouse gas storage assessment permit in the Petrel sub-basin 250 km off the coast from Darwin but their intention is to only inject the first CO<sub>2</sub> from Ichthys by the end of this decade. CCS would enable an approximate 40% reduction in greenhouse gas emissions from Ichthys but leaving 60%.

Santos has a more advanced CCS project. It is developing a large CCS project at Moomba. By Q1 2023 the project was 60% complete with first injection expected in early 2024.

## 5.1 Australian Safeguard Mechanism

A new Australian government took office in May 2022. One of its first moves was to update Australia's Nationally Determined Contribution to emissions reduction, committing to reduce greenhouse gas

<sup>&</sup>lt;sup>57</sup> Raab, M and O'Brien, G. (2023). 'Carbon capture and storage's role within Australia's energy transition: necessary, safe, and reliable'. Presented to 2023 APPEA Conference, Adelaide.

<sup>&</sup>lt;sup>58</sup> https://www.bloomberg.com/news/articles/2023-05-17/chevron-s-carbon-capture-flagship-is-stuck-at-one-third-capacity



emissions to 43% below 2005 levels by 2030. This was substantially more ambitious than the previous government's 26-28% target and one of the new government's highest priority policy commitments.

One of the policies aimed at speeding up emissions reduction is toughening the Australian Safeguard Mechanism, which has been in force since 2016. The Mechanism applies to industrial facilities that emit more than 100,000 tonnes of CO<sub>2</sub>e each financial year. The gas projects listed in Table 4 all come under the Safeguard Mechanism, including all LNG projects. The changes to the policy are to require covered facilities to reduce their greenhouse emissions by 4.9% pa. New gas fields supplying existing LNG facilities will be treated as new facilities so that they are given international best practice baselines for the CO<sub>2</sub> in their new fields. For these fields' reservoir emissions, best practice is zero net emissions given the existence of low- CO<sub>2</sub> fields and opportunities for carbon capture and storage. This will effectively mean that all CO<sub>2</sub> emissions from new gas fields will either need to be avoided or offset through the surrender of Australian Carbon Credit Units (ACCUs) and Safeguard Mechanism Credits (SMCs).

The notion that best practice for LNG is net zero emissions is problematic. LNG production produces emissions. Data on emissions from LNG projects in other countries is not disclosed (with the exception of the U.S.). Still, LNG companies are promoting their progress in shipping net zero LNG cargoes.

The policy is tougher on gas projects than other industries and reflects a deal done by the government with the Greens to enable the legislation to pass Parliament. (It was opposed by the centre-right Opposition.) New LNG projects that may be affected by the policy include the Barossa gas field being developed to backfill Darwin LNG (18% CO<sub>2</sub>), Scarborough to feed Pluto Train 2 (only 0.5%), the Crux gas field being developed to supply Prelude (11.6%), Browse LNG (8-12%) and the Plover gas field intended to supply Ichthys (17%)<sup>59</sup>. This all represents a tightening of future Australian LNG supply.

## 6. June 2022 east coast energy crisis

While there are increasing constraints on gas development to maintain LNG and domestic gas production, there is also an increasing need for peak gas to support the energy transition.

Like many other countries Australia is in the middle of an energy transition but with a different starting point. As a dry continent, Australia only has limited hydro resources. Although the country is one of the world's major uranium exporters and is in the process of acquiring nuclear submarines, it has no nuclear electricity generation, based on long standing government anti-nuclear policies. What it does have is plenty of coal, with heavy reliance on coal for electricity generation. In 2022 59% of east coast electricity was still being generated from coal<sup>60</sup>. As part of the energy transition coal-fired generation is now declining quickly (down from 63% the year before) and increasingly unreliable.

For 2022 as a whole, higher generation from wind and solar more than offset lower generation from coal and gas. However, this was not the case in mid-2022, the start of the southern winter. when both coal generation and solar generation were down. East coast electricity prices spiked to over \$200/MWh in the June quarter, spot gas prices to over \$30/MMBtu and coal prices to over \$400/tonne. The ABS gas Producer Price Index for the east coast, which reflects contract prices as well as spot prices, jumped by 52% in Q2 compared with a year previously (Figure 3).

This was due to both international and domestic developments.

Higher international prices had a flow-on effect domestically, including to electricity prices. In addition, there were disruptions to coal-fired power generation. Flooding caused delays in the delivery of coal to some NSW power stations.

 <sup>&</sup>lt;sup>59</sup> https://www.afr.com/companies/energy/gas-projects-on-the-line-as-safeguard-belt-tightens-20230329-p5cw66
 <sup>60</sup> EnergyQuest (2023). 'EnergyQuarterly March 2023: The Government takes over',

https://www.energyquest.com.au/energyquarterly-march-2023-the-government-takes-over/



The east coast electricity market is an energy-only market rather than a capacity market<sup>61</sup>, which values availability. Commonwealth and state energy ministers met in December 2022 to consider a recommendation from the Energy Security Board for a broad-based capacity mechanism, including coal and gas. This was quickly dubbed "coal keeper" by activists and ministers decided to limit any capacity mechanism to "zero emissions dispatchable generation and storage technologies"<sup>62</sup>.

Some of the existing coal plants were built as long ago as the 1970s. These plants, which were intended to provide steady baseload generation, are increasingly unreliable and have had increasing difficulty competing in a market with intermittent renewables.

As winter approached last year there were disruptions to several coal generators as well as the longplanned closure of one unit at Liddell, a major power station in NSW (subsequently closed completely). Total second quarter coal-fired generation was down by 7% compared with a year earlier, while total electricity demand was up by 1%. Around two-thirds of the gap was met by wind, solar and hydro but that left 1,000 GWh to be supplied by gas-fired power generation, increased by 29% from a year earlier<sup>63</sup>.

The increase in international energy prices, the fall in coal generation, and the ramp-up in the gas price sent prices spiralling in domestic gas and electricity spot markets. AEMO was forced to close the electricity and gas markets and direct generation to maintain system stability and energy security.



#### Figure 7: Gas prices at WGSH vs LNG feedstock volumes

Source: AEMO

Gas was the immediate scapegoat for these problems, particularly the Queensland LNG producers. Figure 7 shows Queensland LNG feedstock volumes and Queensland spot gas prices at the Wallumbilla Gas Supply Hub (WGSH). Spot gas prices started increasing in March while the volume of gas feeding the LNG plants was falling. As happens every winter, gas from Queensland was flowing south into the colder southern states.

<sup>&</sup>lt;sup>61</sup> The challenges of the energy transition for the energy-only NEM are discussed in Billimoria, F. and Poudineh, R. (2018). 'Electricity Sector Transition in the National Electricity Market of Australia: Managing Reliability and Security in an Energy-Only Market. OIES Paper: EL 31. https://www.oxfordenergy.org/publications/electricity-sector-transition-national-electricity-marketaustralia-managing-reliability-security-energy-market/

 <sup>&</sup>lt;sup>62</sup> https://www.energy.gov.au/government-priorities/energy-and-climate-change-ministerial-council/meetings-and-communiques
 <sup>63</sup> EnergyQuest (2022). 'EnergyQuarterly September 2022: Please coal don't go just yet'.

https://www.energyquest.com.au/energyquarterly-september-2022-please-coal-dont-go-just-yet/



Speaking after a meeting of federal and state energy ministers on 12 August, the Victorian and NSW ministers were particularly virulent about Queensland LNG exports.

"We produce more than sufficient gas to meet our needs, but the problem is too much of it has been allowed to be exported at our own cost, and that's got to change," Victoria state energy minister Lily D'Ambrosio said at a televised media conference (Reuters, 12 August).

Then NSW energy minister Matt Kean said, "And what we need to do is prioritise Australian gas for Australian gas users ahead of companies making super profits and exporting that gas offshore," (Reuters 12 August). NSW is of course one of the world's major coal exporters.

Both states have long-running bans on gas development, and found themselves short, whereas other states were able to meet their gas supply needs.

The Australian competition regulator was quick to throw fuel on the fire with inflated claims that the LNG producers were profiteering by selling spot LNG rather than supplying gas domestically.

Rising and volatile spot prices in electricity and gas markets triggered the automatic application of administered price caps by AEMO, commencing in the Victorian gas market from 30 May, and in the mainland NEM regions over 12-13 June. Separately, gas prices in the trading hubs of Sydney and Brisbane were also capped from 24 May to 7 June. Sydney hub prices were also capped between 8 June and 14 June when high price thresholds were breached.

As administered price capping commenced in the NEM, generation volumes offered into the spot market began to drop. Combined with a large number of prior outages, this led to shortfalls in actual and forecast reserves which triggered a range of interventions by AEMO to maintain power system reliability and security. AEMO has said that it declared 406 separate Lack of Reserve (LOR) conditions in Q2 2022, compared with 36 in Q1 2022 and 73 in Q2 2021. The scale of interventions needed to manage the extent of reserve shortfalls made the operation of the market in accordance with the National Electricity Rules impossible and AEMO suspended operation of the NEM spot market in all regions between 15 June and 24 June, when full spot market operation recommenced.



Figure 8: NEM generation 2009 Q1 to 2022 Q2 (GWh)

Source: AEMO

Overall, the east coast energy crisis reflected electricity issues more than gas. Figure 8 provides a longterm perspective on the changing fuel mix in the east coast National Electricity Market (NEM, which excludes WA). Although coal is in long-term decline, it still dominates NEM generation. In Q2 coal



provided three times the output of variable renewable generation (VRE), wind and solar, and six times gas generation.

The decline in coal is being generally replaced by the growth of VRE. However, if the decline of coal gets ahead of growth in renewables or if renewables are impacted by weather, gas is the only assured means of filling the gap quickly.

Until 2017 gas generated around 5 TWh per quarter in the NEM and this was reasonably stable but it has since become far more volatile. In Q2 2022 gas-fired generation (GPG) was 4.7 TWh but two quarters earlier it was only 2.1 TWh. GPG has been in decline since 2020. Given this uncertainty any generators with take-or-pay contracts have had a strong incentive to on-sell their gas to the LNG projects. Then, when in Q2 NEM electricity demand increased by 0.6 TWh and coal fell by 2.4 TWh, the market was suddenly short 3.0 TWh. VRE contributed an additional 1.6 TWh, leaving 1.0 TWh, for which gas was the only reliable option. A fairly modest-sounding decline in coal generation of 7% required a 29% increase in GPG, with predictable consequences for spot gas prices. The NEM now lacks resilience to even modest shocks.

This is particularly the case when international gas and coal markets are tight. Figure 9 shows the ACCC LNG netback (driven by Asian LNG spot prices), spot gas prices at the Queensland Wallumbilla Gas Supply Hub (WGSH) and the ex-Newcastle thermal coal export price.



#### Figure 9: International and east coast energy prices (\$/GJ)

Source: ACCC, AEMO, Trading Economics

Since 2018 the ACCC has been publishing an east coast LNG netback price based on the forward curve for the Platts Japan Korea Marker (JKM) price for Asian spot LNG. This was regarded as a reasonable benchmark for east coast gas contract prices, monitored by the ACCC, with a focus on any cases of gas contracting at above netback prices. However, this backfired with the volatility of JKM prices reaching unprecedented levels in 2022 and netbacks reached extraordinary levels.

East coast prices are influenced by international LNG prices but more by oil prices (to which the price of most Australian LNG is indexed) than LNG spot prices. Movements in international energy prices due to the Ukraine war were used to justify the subsequent government intervention. However domestic gas prices are also heavily influenced by domestic developments in the electricity sector. In early 2021 spot LNG prices spiked due to the cold northern winter. However domestic prices hardly moved. Then in mid-2021 domestic prices spiked due to a fire at the Callide coal-fired power station in Queensland. Domestic prices then retreated while international prices were increasing. Spot gas domestic gas prices were below the ACCC netback from August 2021 to April 2022 but domestic prices rose sharply in May



2022 reflecting the issues in the NEM. By June domestic prices had exceeded the ACCC benchmark for the first time since July 2021. As of April 2023, the east coast spot gas price averaged A\$12.20/GJ (\$8.66/MMBtu), well below the ACCC LNG netback of A\$17.50/GJ (\$12.43/MMBtu).

It remains to be seen whether the events of 2022 are repeated in the coming winter. Much will depend on the weather, the ramp-up of firm renewables, the performance of coal-fired generation and the ability of gas to plug any gaps. It will also depend on whether the recent federal government market interventions have weakened the ability of gas to respond to shocks in the NEM. However, the timing for two important east coast backup power projects is slipping The Snowy Hydro 2.0 pumped hydro project is running almost five years behind its original schedule and the 660 MW Kurri Kurri peaking gas plant is running a year late<sup>64</sup>.

The June 2022 crisis catalysed a domestic policy initiative to control gas (and coal) prices to reduce the pressure on electricity prices, while if necessary, maintaining the domestic gas supply by limiting LNG exports.

## 7. A new government and new policies

The east coast energy crisis in June 2022 occurred only weeks after the installation of a new government in Canberra, the centre-left Labor government. The new government was confronted with rising inflation, to which the east coast energy crisis was contributing, with official forecasts of a 36% increase in retail electricity prices and a 20% increase in retail gas prices in 2023-24. Figure 10 shows the recent surge in retail electricity and gas prices.



#### Figure 10: Australia consumer price index, annual movements (%)

#### Source: Australian Bureau of Statistics

Commenting on retail gas price increases in the March 2023 Consumer Price Index (CPI), the Australian Bureau of Statistics said, "Price reviews reflecting higher wholesale gas prices led to rises in gas and other household fuels, with rises seen across all capital cities. The annual rise in gas prices of 26.2 percent is the largest on record, reflecting this quarter's rise as well as price reviews in the September

<sup>&</sup>lt;sup>64</sup> https://www.theaustralian.com.au/nation/twoyear-delay-to-snowy-20-sparks-fears-over-supply-shortfalls-price-surgesblackouts-and-emissions-reductions-target/news-story/ae637056eab3dc79818d4f610be938ca



quarter 2022<sup>65</sup>". The CPI is a key indicator of inflation and is an input into setting politically sensitive official interest rates. The government had also come to office promising lower electricity prices and higher real wages.

The appropriate response to unexpected economic shocks is always difficult. The government rejected the option of direct welfare assistance on the grounds of cost and its possible inflationary effects. It decided instead for caps on wholesale fuel prices, notwithstanding the hidden costs, lack of targeting and disincentives to new supply. However, the government has since (as of May 2023) also introduced a program of energy price relief for five million households and one million businesses<sup>66</sup>.

## 7.1 Gas price cap

Legislation was passed in mid-December 2022 to give the federal government far-reaching powers to intervene in the gas market to cap the rise in gas prices. The package of measures from the government included a A\$12/GJ (\$8.50/MMBtu) price cap on new east coast domestic wholesale gas contracts for 12 months and a mandatory code of conduct for the gas market including reasonable price and arbitration provisions. Australia also announced a temporary A\$125 (\$84) per-tonne cap on coal prices.

The Australian intervention is particularly heavy-handed. The gas price cap is significantly lower than the EU gas price cap of 180 €/MWh, (\$56/MMBtu, A\$76/GJ)<sup>67</sup>.

In its 2023 budget announced on 9 May the government claims that its interventions have been successful in reducing inflation in retail electricity and gas prices, with price increases in 2023-24 now revised down to 10% for electricity and 4% for gas. Given that international prices have also fallen significantly it can be argued that a large part of these reductions may have happened anyway. The intervention has also incurred the costs of distorting the operation of the market and weakening investment confidence.

## 7.2 Australian Domestic Gas Security Mechanism (ADGSM)

The gas price cap was soon followed by major changes to the ADGSM, which were announced in February 2023. Activation of the ADGSM is now to be considered on a quarterly basis, rather than annually. The new ADGSM can also be triggered in respect of the Western Australian and NT gas markets as well as the east coast. All LNG projects in a particular market are to share the liability for any shortfall equally in volumetric terms, rather than in accordance with the pre-existing Total Market Security Obligation, under which export allowances were previously determined, depending on whether an LNG project was considered to be a net-contributor to the domestic gas market, or in net-deficit. LNG export permissions are to be made tradeable, in order to improve the economic efficiency of the ADGSM by maximising flexibility in the market while ensuring domestic supply. Long-term export contracts which were entered into to underpin a final investment decision are offered some protection, but this protection is qualified by a requirement for a producer to exhaust all available commercial solutions before it will be granted an increase to its export permission.

Limiting LNG exports in response to a short-term domestic shortfall of 50 PJ would only reduce east coast exports by around 1 Mt or less than 5% of exports. However, in a scenario where southern gas supplies continue their rapid decline and in the absence of LNG imports, exports could be limited by 2-4 Mtpa by 2030. Interestingly this is likely to have a bigger impact on Chinese buyers, who accounted for 53% of east coast purchases in 2022. Japanese buyers accounted for 13%.

<sup>&</sup>lt;sup>65</sup> https://www.abs.gov.au/statistics/economy/price-indexes-and-inflation/consumer-price-index-australia/latest-release

<sup>&</sup>lt;sup>66</sup> https://www.abc.net.au/news/2023-05-07/federal-budget-to-offer-500-energy-bill-relief-package/102314002

<sup>&</sup>lt;sup>67</sup> The EU price cap was deliberately set high so as not to be triggered plus there were so many exemptions that it would be likely to be totally ineffective. See Barnes, A. (2022). 'EU Commission proposal for joint gas purchasing, price caps and collective allocation of gas: an assessment'. OIES Paper:NG 176.



The ACCC has since advised that no east coast domestic shortfall is expected in winter 2023 and the Minister of Resources has not activated the ADGSM<sup>68</sup>.

#### 7.3 East coast gas code of conduct

In relation to the mandatory code of conduct proposed with the gas price cap, there were particular concerns about the gas reasonable price provision, which would have been a cost-plus form of price regulation similar to regulated infrastructure rates of return but difficult to apply to the higher risk upstream gas sector. Following an initial consultation, the government released a second consultation paper in April 2023 that abandons the reasonable price and arbitration provisions but extends the A\$12/GJ gas price cap. It also allows for exemptions from the cap if producers satisfy the ACCC they would deliver gas to the domestic market. Small producers would also be exempt if they only supply the domestic market. (The code does not cover retailers and there are no apparent restraints stopping domestic gas buyers from reselling gas at a higher price.)

Exemptions for large gas producers will be at the joint discretion of two ministers and will need to be approved by five separate government agencies. Exemptions will start at 12 months in length, meaning projects will need to reapply for exemption. Large gas producers have been asked to make submissions on the supply and price commitments they would be prepared to make under the proposed exemption framework. However, according to media reports several large east coast producers will not submit proposals to the government, regarding the proposed rules as unworkable<sup>69</sup>. The proposal, which is all "sticks" and no "carrots" is unlikely to encourage new upstream investment.

Under the new arrangements, it is likely that LNG producers would have their exports restricted and have to sell the diverted gas at the capped price.

## 7.4 Petroleum Resources Rent Tax (PRRT)

The federal government has also increased taxation on offshore LNG projects.

Australian LNG producers pay federal company tax on taxable profits. Offshore producers (Western Australia and the Northern Territory) are liable for federal PRRT and Queensland producers pay state royalties.

There have been long-standing claims that the industry is too lightly taxed<sup>70</sup>. The Australian Tax Office has mounted successful court actions against oil and gas company attempts to minimise their company tax obligations<sup>71</sup>.

There have also been concerns about the relatively low level of tax revenue from PRRT. This is a profitbased tax that becomes payable (at a rate of 40%) once a project's costs have been recouped. With some of the world's most expensive LNG projects it is not surprising that recouping costs has been a lengthy process. As of 2023 not a single LNG project had paid PRRT and many were not expected to pay significant amounts of PRRT until the 2030s<sup>72</sup>.

In its 2023 Budget in May 2023 the government has introduced changes to the PRRT to deliver a cap on the use of deductions to offset assessable income of LNG producers under the PRRT. The cap will limit LNG projects' deductions each year to no more than 90% of their assessable income, so that the PRRT will be paid on at least 10% of income. The amounts that are unable to be deducted because of the cap will be carried forward and uplifted at the government long-term bond rate (a lesser escalation

p5bmqc#:~:text=The%202017%20Chevron%20dispute%2C%20which,Corporation%20in%20Delaware%20borrowed%20%24 US2. https://www.afr.com/companies/energy/tax-breaks-for-miners-clarified-in-response-to-shell-case-20230509-p5d718

<sup>&</sup>lt;sup>68</sup> https://www.minister.industry.gov.au/ministers/king/media-releases/improved-east-coast-gas-supply-

outlook#:~:text=The%20latest%20report%20from%20the,for%20the%20remainder%20of%202023.

<sup>&</sup>lt;sup>69</sup> https://www.afr.com/companies/energy/gas-tensions-rife-as-producers-stall-on-supply-promises-20230504-p5d5qq

<sup>70</sup> https://treasury.gov.au/publication/p2023-388153

<sup>&</sup>lt;sup>71</sup> https://www.afr.com/politics/federal/ato-knocks-out-40b-in-resources-write-offs-thanks-to-chevron-win-20221003-

<sup>72</sup> https://treasury.gov.au/publication/p2023-388153



rate than previously). To minimise the impact of early payments on new projects, they will not be subject to the cap until seven years after the first year of production<sup>73</sup>.

The industry response to these tax changes has been relatively mild. Some of the other options considered by the government could have been far more onerous<sup>74</sup>. However, INPEX is one of the companies likely to have to pay PRRT much earlier than it expected. Also, this is in addition to all the other policy changes discussed above.

## 8. Conclusions

Will the Australian government be able to live up to its promise of remaining a significant and reliable long-term LNG supplier or is it really quietly quitting the LNG business as INPEX has suggested? The analysis in this paper suggests that it is the latter. This is not only due to government actions. Fundamentally, Australia is not replacing its gas reserves sufficiently to maintain production at current levels and this is despite high energy prices. There is massive uncertainty globally about the future of gas, ranging from half-hearted support as a transition fuel to outright opposition. This is influencing gas producers in Australia as everywhere else, turning against gas exploration and development and redirecting investment to clean energy or returning the money to shareholders. This would be a good thing if there is a smooth energy transition but so far the transition is far from smooth for Australia, as exemplified in the east coast energy crisis in winter 2022. Australia of course is not unique in facing this challenge.

While gas producers have complained about the recent Australian government interventions, warning of negative long-term consequences, the government appears to believe it is on a winner politically. The centre-right Opposition does not support the government interventions but the politically powerful Greens do not think they go far enough.

Attitudes to gas and LNG development have changed hugely in the decade since Australia's new LNG projects were sanctioned (and with general political support). Climate change and greenhouse emissions from fossil fuels are much more important, particularly with increasingly frequent major weather events. Australian attitudes to China have changed and there is an increasing focus on industrial policy. The Ukraine war has led to a swing towards protectionism and resource nationalisation. COVID increased the focus on secure supply chains and re-establishing domestic manufacturing. Government intervention is generally more popular now than it was a decade ago. In Australia too, the states have always been more important than the federal government in resource development and COVID made them more parochial. In relation to LNG, the gas issues on the east coast have given the whole LNG industry a bad name.

The recent government interventions also reflect these changed community attitudes. To meet domestic and export gas demand, more gas supply is needed and there are more than sufficient Contingent Resources to ensure this. However, the barriers to development keep increasing, as do the chances that gas from LNG projects will be diverted to meet domestic needs.

Australia certainly has the geological potential to continue to grow LNG exports as the U.S. and Qatar are doing and the comments of the Japanese suggest that there are willing buyers, keen to keep buying Australian LNG to help them work through their own energy transitions. However, this cannot happen without significant new gas development, which is increasingly challenging. Without significant new gas development, which is more likely to be around 65 or 70 Mt. Australia will still be one of the world's major LNG suppliers but declining rather than growing and somewhat less reliable than it was in the past. This is clearly a matter of concern to the Japanese and other major customers.

<sup>73</sup> https://treasury.gov.au/publication/p2023-388153

<sup>&</sup>lt;sup>74</sup> https://www.afr.com/politics/federal/2-4b-prrt-increase-must-be-the-last-gas-sector-says-20230507-p5d6cw

https://www.afr.com/politics/federal/gas-armistice-as-industry-realises-it-could-have-been-a-lot-worse-20230508-p5d6nq



# Abbreviations and units of measurement

2P	proved and probable reserves
\$	US dollar
A\$	Australian dollar (0.67\$)
ABS	Australian Bureau of Statistics
ADGSM	Australian Domestic Gas Security Mechanism
AEMO	Australian Energy Market Operator
ATO	Australian Tax Office
Bcf	billion cubic feet
Bcm	billion cubic metres
CCS	carbon capture and storage
CO <sub>2</sub> e	carbon dioxide equivalent
CPI	consumer price index
CSG	coal seam gas
CSIRO	Commonwealth Scientific and Industrial Research Organisation
GJ	gigajoule
GPG	gas power generation
LNG	liquefied natural gas
Mcf	thousand cubic feet
MMBtu	million BTU
Mt	million tonnes
Mtpa	million tonnes per annum (LNG)
NWS	North West Shelf
PJ	petajoules
Tcf	trillion cubic feet
tpa	tonnes per annum
TJ/d	terajoule per day
VRE	variable renewable generation
WGSH	Wallumbilla Gas Supply Hub



## Approximate conversion factors for natural gas and LNG

sales gas 1 billion cubic feet (Bcf) = 1.06 PJ LNG 1 million tonnes (Mt) = 55.43 PJ LNG 1 tonne (t) = 0.4157 cm sales gas 1 petajoule (PJ) = 26.71 MMcm 1 MMBtu = 1.055 GJ = 1Mcf = 10 therms 1 billion Btu = 1.055 TJ = 1 MMcf 1 trillion Btu = 1.055 PJ = 1 Bcf

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