Institute for Energy Economics and Financial Analysis
ieefa.org

91 Percy Street
Warwick, QLD 4370
aus_staff@ieefa.org

17 November 2023

To: Department of Industry, Science and Resources

RE: Future gas strategy consultation

Thank you for the opportunity for the Institute for Energy Economics and Financial Analysis (IEEFA) to present its submission to this consultation.

Regards,

Amandine Denis-Ryan – Chief Executive, IEEFA Australia

Kevin Morrison – Energy Finance Analyst, Australian Gas

Joshua Runciman – Lead Analyst, Australian Gas

Jay Gordon – Energy Finance Analyst, Australian Electricity

Submitted via email.

91 Percy Street
Warwick, QLD 4370
aus_staff@ieefa.org

Key points

91 Percy Street
Warwick, QLD 4370
aus_staff@ieefa.org

Figures

91 Percy Street
Warwick, QLD 4370
aus_staff@ieefa.org

Gas use in Australia

A compelling business case to accelerate cost-effective residential electrification

In IEEFA's submission to the Senate Inquiry into Residential Electrification,[1] we noted that:

- Gas-consuming households are more exposed to energy price inflation than all-electric homes, which generally have lower energy bills;
- Electricity networks are unlikely to present a major barrier to electrification. In fact, CSIRO analysis for Energy Consumers Australia found increasing network utilisation could reduce costs for all consumers;[2]
- Residential electrification is one of the most cost-effective decarbonisation options, and electric appliances have far lower lifetime emissions than gas appliances, and;
- Residential electrification is economical today, and delaying this transition would lock in higher energy costs for consumers.

Realising these benefits will require intentional action from governments, including to:

- Encourage take-up of cost-effective residential electrification;
- Reduce barriers to electrification;
- Support the development of strong workforces and supply chains;
- Capitalise on the benefits of distributed energy resources, and;
- Improve the energy efficiency of Australian homes.

A recent IEEFA report[3] found that one of the most impactful steps governments could take would be to end the sale of gas appliances as early as 2025.

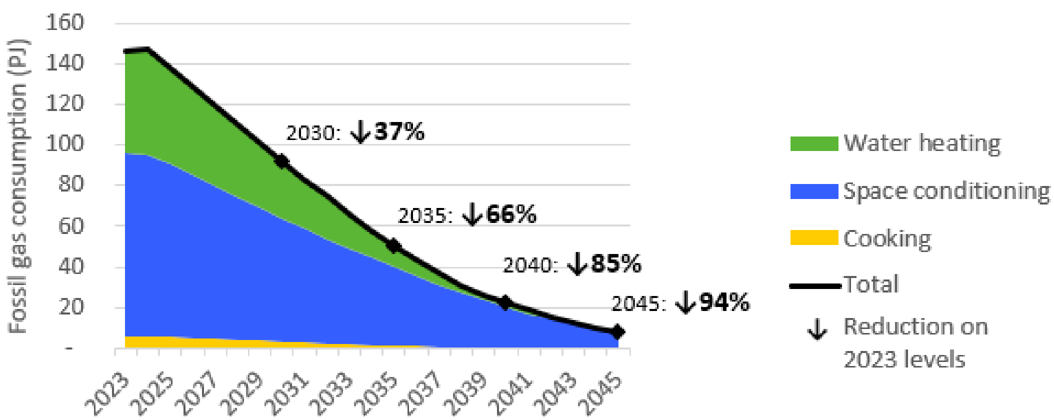
In Victoria, the state with the largest residential gas consumption, this would mitigate the need for costly new gas supply projects while bringing financial savings to consumers, reducing their exposure to asset stranding risk, aligning emissions closely to the state's economy-wide targets and providing an equitable solution for renters.

These findings are also relevant to other states and territories. For example – if no new gas appliances were sold nationally from 2025, we find national residential fossil gas demand could reduce by 94% by 2045. (Figure 1).

[1] IEEFA. Senate inquiry on residential electrification. 28 September 2023.
[2] CSIRO. Consumer impacts of the energy transition: modelling report. July 2023. Page 19.
[3] IEEFA. Managing the transition to all-electric homes. 2 November 2023.

91 Percy Street
Warwick, QLD 4370
aus_staff@ieefa.org

Figure 1: Effect of replacing gas appliances with electric on residential fossil gas demand



Source: IEEFA modelling drawing on EnergyConsult (2022).

Enormous untapped, cost-effective potential to reduce gas demand in Australia

IEEFA Australia recently released a report looking at some of the untapped, cost-effective opportunities for energy efficiency and electrification in the Australian southern states. The report's executive summary states that:

"Australia is leaving many cost-effective opportunities to quickly reduce gas demand on the table. It is lagging on energy efficiency, which offers significant untapped opportunities. It is estimated that an average existing home requires about five times more energy for heating and cooling than a new home built in 2024. This increases to more than eight times for the least efficient 5% of homes. Victorian examples suggest that relatively simple upgrades could reduce gas use for heating by more than 40%, with a return on investment of 16%. Industrial energy efficiency is also significantly untapped with large opportunities in better data analysis and revisiting how to best deliver energy services. For example, a recent program found that 80%-90% of the energy used by compressed air systems is wasted.

"Electrification with efficient heat pumps also has the potential to dramatically reduce gas use in residential buildings and industry. If gas appliances were replaced by efficient electric appliances at the end of their life, the average Victorian home could save $1,200 a year on its energy bills. IEEFA estimated that each year of delay to ending the sales of new gas appliances costs Victorians a collective $912 million in locked-in lifetime costs. In many cases, early retirements of appliances are also cost-effective. Heat pumps are already available for the medium temperatures required in most light manufacturing applications and are being developed for higher-temperature applications.

"Implementing both energy efficiency and electrification interventions in parallel will deliver additional financial benefits, such as ensuring that new equipment is not oversized or unnecessary.

91 Percy Street
Warwick, QLD 4370
aus_staff@ieefa.org

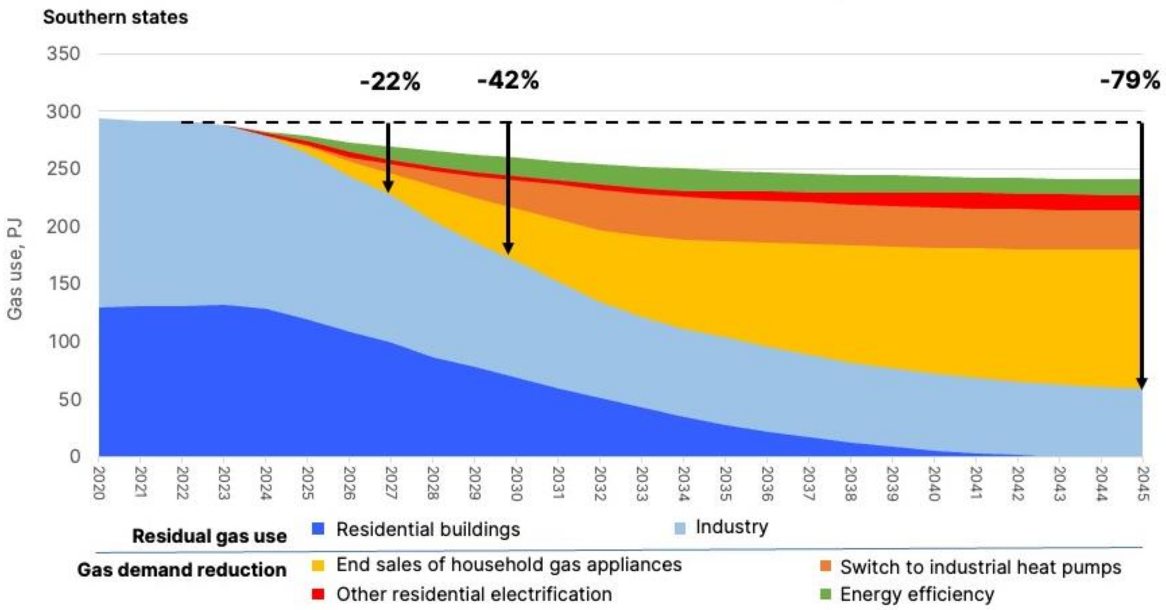
"IEEFA modelled nine illustrative energy efficiency and electrification opportunities in southern states' residential buildings and industry. While the modelling is indicative only and does not fully capture the potential benefits, it nonetheless illustrates the size of the potential.

"The modelled interventions deliver significant gas use reductions in the long term: residential buildings' gas use decreases to zero by the early 2040s; and industrial gas use decreases by more than 60% by 2045 compared with 2022. In total, the interventions achieve a near 80% reduction in gas use across residential buildings and industry. They also achieve significant gas demand reductions in the short term, with a reduction in gas demand of about 22% by 2027 and a 42% reduction by 2030 compared with 2022.

"The reduction in gas demand is particularly high in Victoria, with reductions of 30%, 52% and 93% respectively in 2027, 2030 and 2045 compared with 2022. This is due to the strong probable decrease in gas use for oil and gas production and associated chemicals production over the next two decades.

"We found that these reductions could eradicate the gas supply gap. They could also reduce the requirement to redirect northern gas supplies to meet southern states' demand."[4]

Figure 2: Cost-effective interventions could slash southern states' gas demand



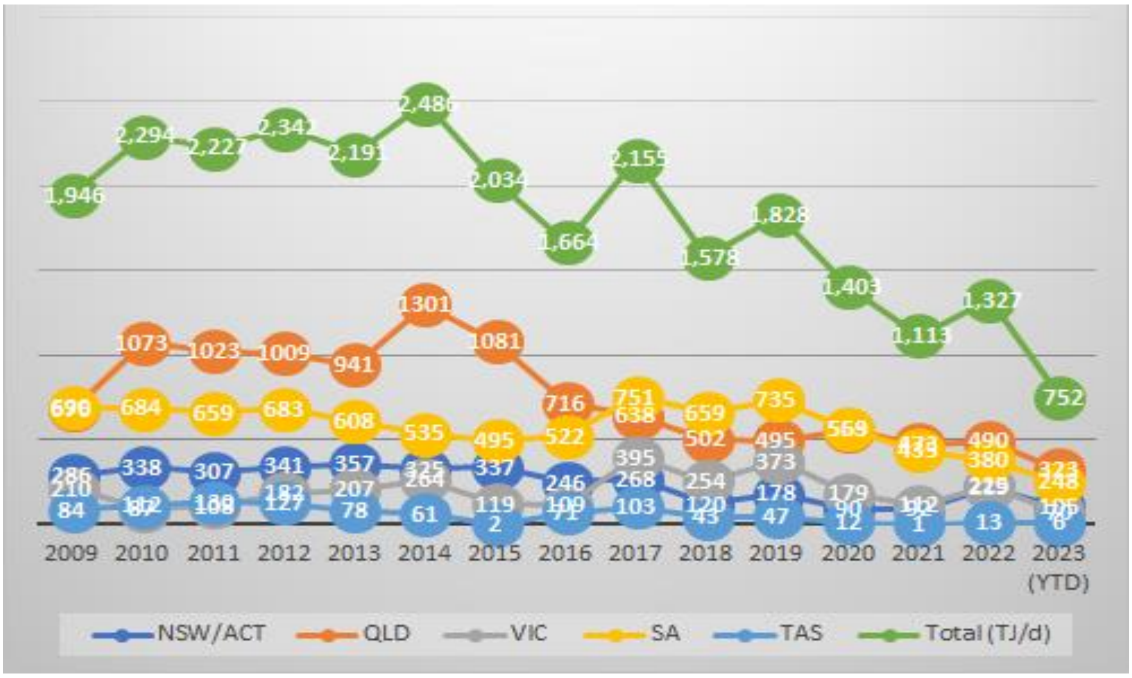
Source: IEEFA

Gas generation unlikely to be a large demand source in the future

Figure 3 shows that gas used for generating electricity in Australia has fallen almost 32% between 2009 and 2022, and is on track to fall further this year based on data from the Australian Energy Regulator (AER) for the nine months to 30 September 2023.[5]

[4] IEEFA. Reducing demand – A better way to bridge the gas supply gap. November 2023. Pages 5-6.
[5] AER. Industry statistics. 2023.

Figure 3: Eastern Australia's gas use for power generation (TJ/day)



Source: Australian Energy Regulator, industry statistics.

The prospect of further declines in gas-fired power generation are likely with two gas-fired power stations earmarked for closure by 2026. This comprises the 800MW Torrens Island B power station, the largest gas-fired power plant in the National Electricity Market (NEM), and the 180MW Osbourne power station, both in South Australia.[6] A third gas-powered station in South Australia is to close by 2032 when the 240MW Hallett gas turbine is due to shut its doors. The three plants have a combined generation capacity of 1,220MW.

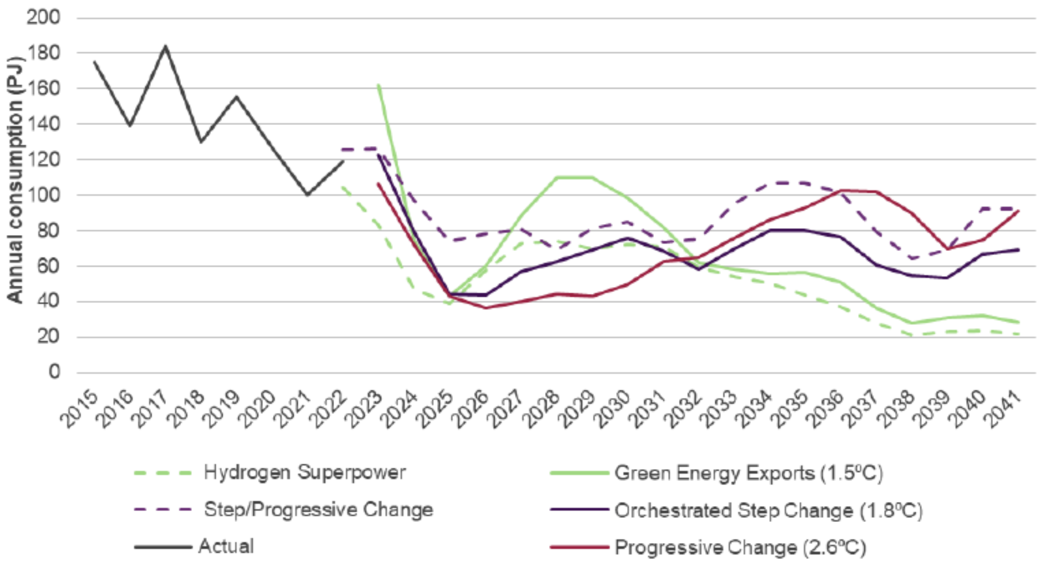
AEMO anticipates two open-cycle gas turbine (OCGT) generators will come online by the end of 2024: the 320MW Tallawarra B and the 750MW Kurri Kurri gas plants, both in New South Wales (NSW), which amount to a combined 1,070MW.[7] This will result in a net reduction in gas-fired power capacity over the AEMO 10-year outlook period. Both the new gas plants are to be used as peaking power plants. They will not be running as much as Torrens Island B has been over its 47-year life as it has been a baseload-type power plant running most of the day.[8] Peaking power plants traditionally operate only a few hours a day.

AEMO in its 2023 Gas Statement of Opportunities (GSOO) forecast a reduction in gas consumption for electricity generation across all its scenarios (see Figure 3). In its central scenario *Orchestrated Step Change (1.8°C)*, gas use for electricity generation halves by 2045 compared to 2022, and in its *Green Energy Exports (1.5°C)* scenario it reduces by 80% over the same period.[9]

[6] AEMO. 2023 Electricity Statement of Opportunities. August 2023. Page 8.
[7] Ibid. Page 46.
[8] AGL. Torrens Island 'B' Power Station to close by 2026. 24 November 2026.
[9] AEMO. 2023 Gas Statement of Opportunities. Report figures and data. March 2023. Figure 18.

91 Percy Street
Warwick, QLD 4370
aus_staff@ieefa.org

Figure 4: Actual and forecast NEM gas generation consumption, all scenarios and compared with 2022 GSOO, 2015-2041[10]



Source: AEMO

In a previous report, IEEFA highlighted how confusing and contradictory AEMO forecasts have been regarding gas use for gas generation: *"AEMO's GSOO presents widely different forecasts for gas use in electricity generation in the most likely scenario than its [Integrated System Plan (ISP)]. The former decreases significantly to 2050 while the other increases materially. The GSOO is meant to guide decisions about future gas supply needs. However, the government seems to be referring to the ISP's forecast of increasing gas generation to inform its decisions regarding gas developments. Federal Climate Change and Energy Minister Chris Bowen said that as the share of renewables sources shifts towards the government's 82% target by 2030, the remaining 18% of power 'will increasingly be focused on gas'."*[11]

Gas generation faces further competition in providing back-up to more solar and wind power capacity coming online by the end of 2032-33, with a greater volume of energy storage capacity expected to enter the NEM over the next 10 years. AEMO's Electricity Statement of Opportunities, which tracks the projects in the development pipeline, anticipates 5,241MW of utility-scale battery projects will come online over the next 10 years.[12] It is likely this number will be higher, as additional battery projects are likely to be announced and battery projects already in the development pipeline are likely to progress further in the coming years. In addition, AEMO estimates two pumped hydro plants will come online by the end of 2030 in Queensland, with a combined capacity of more than 2,200MW, alongside Snowy 2.0 in NSW (2040MW/ 350,000MWh). Together the volume of non-fossil fuel firming capacity that is estimated to come online is about 9,481MW, or around nine times the amount of gas-fired firming capacity to begin operating in the NEM in the same period.

[10] AEMO. 2023 Gas Statement of Opportunities. March 2023. Page 37.
[11] IEEFA. Australia needs 1.5C aligned national energy pathways. June 2023. Page 10.
[12] AEMO. 2023 Electricity Statement of Opportunities. August 2023. Page 8. Note that these figures include projects in the development pipeline that have status of 'in commissioning,' 'committed' and 'anticipated'. It is likely that a significant amount of additional projects will be added to the pipeline in the coming years, increasing this figure.

91 Percy Street
Warwick, QLD 4370
aus_staff@ieefa.org

Domestic ammonia production an ideal early mover to hydrogen

Ammonia production consumes about 35PJ of gas every year,[13] or about 9% of the total gas used by Australian manufacturing in 2022.[14]

Ammonia production already relies on hydrogen, which makes it a prime candidate for the use of green hydrogen. Only limited additional costs are required to allow the direct use of hydrogen as a feedstock instead of gas.[15]

Monash University estimates that "green ammonia will likely be cost-competitive with fossil fuel-produced ammonia by 2030".[16] In addition, in Australia, 95% of ammonia production is used to make explosives for the mining industry.[17] This means that switching to green hydrogen for ammonia would likely have a limited impact on cost of living, compared with countries where it is used primarily to produce fertilisers to support food production.

Australian LNG in the world's transition to net zero emissions

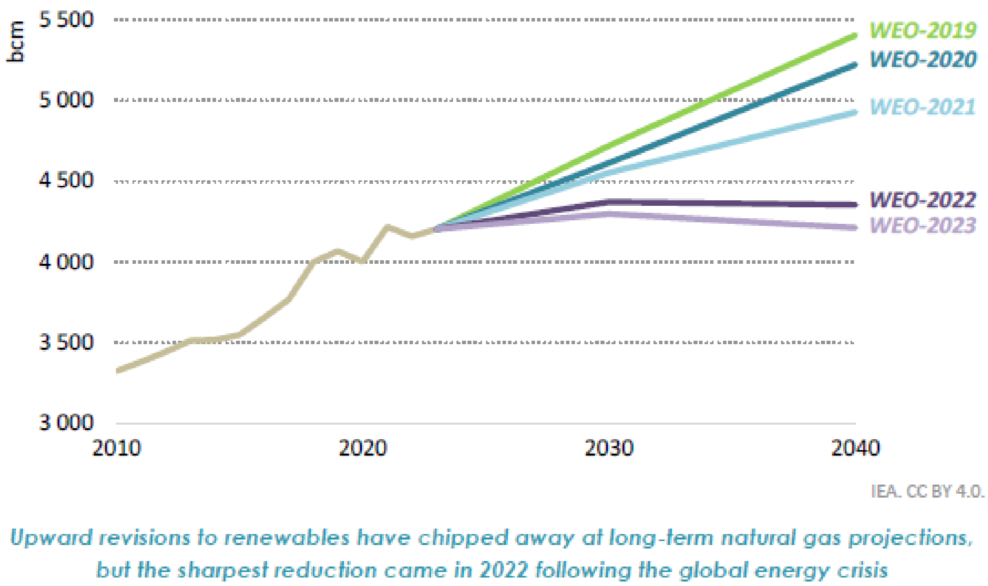
Growing evidence gas has a very limited role in a decarbonising world

The International Energy Agency (IEA) recently published its World Energy Outlook (WEO) for 2023. The report highlighted how fast the expected future demand for gas has been decreasing over the past few years. Even under the Stated Policies Scenario (STEPS, aligned with about 2.4°C warming[18]), the IEA is now expecting gas demand to peak around 2030. The drivers for this decrease in projected demand include: a faster move away from gas in advanced economies, slower projected growth in emerging markets and developing economics and a stronger outlook for renewables.[19]

[13] Climateworks Centre. Pathways to industrial decarbonisation. February 2023. Page 108.
[14] Australian Government Department of Climate Change, Energy, the Environment and Water (DCCEEW). Australian Energy Update 2022. Table F. September 2022.
[15] Climateworks Centre. Pathways to industrial decarbonisation. February 2023. Page 114.
[16] Monash University. Monash Energy Institute. Submission to the Australia's National Hydrogen Strategy Review Consultation. August 2023. Page 13.
[17] Ibid. Page 108; and Government of South Australia, SafeWork SA. Ammonium Nitrate licenses.
[18] IEA. World Energy Outlook 2023. October 2023. Pages 158-159.
[19] Ibid. Page 77.

91 Percy Street
Warwick, QLD 4370
aus_staff@ieefa.org

Figure 5: Gas demand projections in the STEPS to 2040 in the WEO[20]



Source: IEA

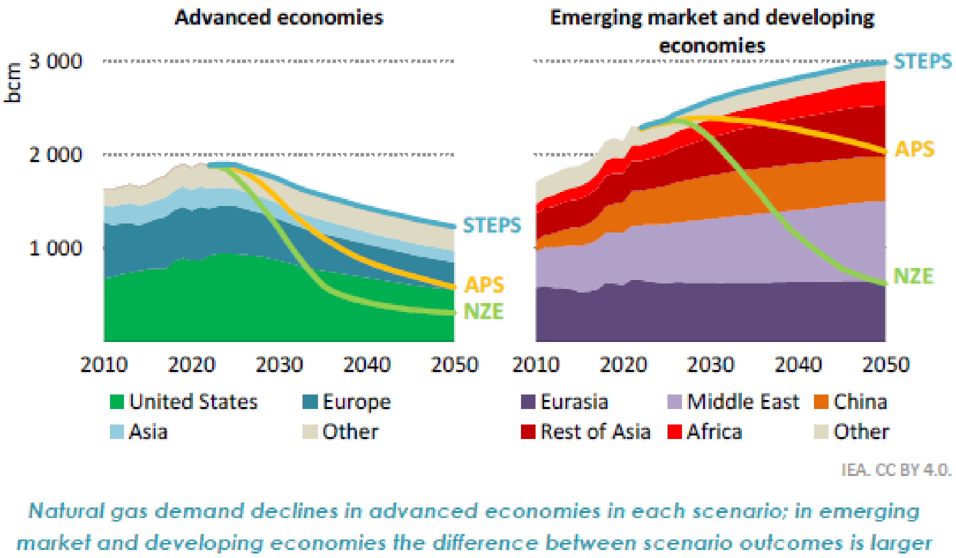
The expected decrease in future gas demand is much stronger in the other scenarios: the *Announced Pledges Scenario* (APS, aligned with about 1.7°C warming) and the *Net Zero Emissions by 2050 Scenario* (NZE, aligned with about 1.5°C warming). "In the APS, demand peaks even sooner, and is 7% lower by 2030 than 2022 levels. In the NZE Scenario, demand falls by more than 2% per year from 2022 to 2030, and by nearly 8% per year between 2030 and 2040."[21]

Gas demand reduces in both advanced and emerging economies in those two scenarios. Gas demand reduces materially in all scenarios in advanced economies,[22] which include Australia's major gas export markets.[23] It also reduces in the APS and the NZE scenarios for emerging markets and developing economies,[24] which represent prospective replacement markets for Australian LNG.

[20] Ibid.
[21] Ibid. Page 136.
[22] IEA. World Energy Outlook 2023. October 2023. Page 137.
[23] Australian Government Department of Industry, Science and Resources (DISR). Future Gas Strategy consultation paper. October 2023. Page 14.
[24] IEA. World Energy Outlook 2023. October 2023. Page 137.

91 Percy Street
Warwick, QLD 4370
aus_staff@ieefa.org

Figure 6: Gas demand by region and scenario 2010-2050[25]



Source: IEA

IEEFA expects that demand forecasts in emerging Asian markets and Asian developing economies will decrease further in coming years. Indeed, IEEFA's *Global LNG Outlook 2023-27* stated that:

"South Asia, including India, Pakistan, and Bangladesh, slashed LNG purchases by 16% last year. Many buyers in the region withdrew from spot markets altogether, and suppliers under long-term contracts often defaulted on cargo deliveries to obtain higher profits in other markets. Rising concerns over fuel supply security and affordability of LNG have downgraded the prospects for LNG demand growth in the region."[26]

"Southeast Asia's LNG industry, once forecasted to be a hot spot for global demand growth, will face financial challenges due to high prices and difficulty in procuring supplies, as well as currency and inflationary pressures. These headwinds will slow the development of LNG value chains that would support long-term demand growth. Key Association of Southeast Asian Nations (ASEAN) economies have pivoted away from LNG to other sources of energy, including coal, domestic gas reserves, liquid fuels, nuclear, and renewables."[27]

Looming LNG supply glut could make projects already under construction unnecessary

In line with IEEFA's Global LNG outlook report, the IEA's WEO 2023 predicted an upcoming LNG supply glut as early as the mid-2020s:

"Starting in 2025, an unprecedented surge in new LNG projects is set to tip the balance of markets and concerns about natural gas supply. In recent years, gas markets have been dominated by fears about security and price spikes after Russia cut supplies to Europe. Market balances remain precarious in the immediate future but that changes from the middle of the

[25] Ibid.
[26] IEEFA. Global LNG Outlook 2023-27. February 2023. Page 4.
[27] IEEFA. Global LNG Outlook 2023-27. February 2023. Page 38.

91 Percy Street
Warwick, QLD 4370
aus_staff@ieefa.org

decade. Projects that have started construction or taken final investment decision are set to add 250 billion cubic metres per year of liquefaction capacity by 2030, equal to almost half of today's global LNG supply. Announced timelines suggest a particularly large increase between 2025 and 2027. More than half of the new projects are in the United States and Qatar.

"This additional LNG arrives at an uncertain moment for natural gas demand and creates major difficulties for Russia's diversification strategy towards Asia. The strong increase in LNG production capacity eases prices and gas supply concerns, but comes to market at a time when global gas demand growth has slowed considerably since its "golden age" of the 2010s. Alongside gas contracted on a longer-term basis to end-users, we estimate that more than one-third of the new gas will be looking to find buyers on the short-term market. However, mature markets – notably in Europe – are moving into stronger structural decline and emerging markets may lack the infrastructure to absorb much larger volumes if gas demand in China slows. The glut of LNG means there are very limited opportunities for Russia to secure additional markets."[28]

"Since natural gas demand peaks in all WEO scenarios by 2030, there is little headroom remaining for either pipeline or LNG trade to grow beyond then. With around 650 bcm of annual liquefaction capacity in operation and a further 250 bcm under construction, global LNG markets look amply supplied in the STEPS until at least 2040. In the APS, LNG demand peaks by 2030 and projects under construction today are sufficient to meet demand. In the NZE Scenario, a global supply glut forms in the mid-2020s and under construction projects are no longer necessary."[29]

Australia unlikely to be a competitive supplier of LNG in the future market

Australia is one of the highest-cost LNG producers globally, and is unlikely to be able to compete with new gas from Qatar and the United States, as a recent IEEFA report states:

"Australia's natural gas cost structure puts it at a competitive disadvantage to some of the world's leading supplier companies and countries, as explained in a Qenos study submitted to the Australian Competition and Consumer Commission (ACCC) LNG Netback Price Series Review in 2021. [Figure 7] highlights the higher cost disadvantage the major LNG producers face in Australia. The figure demonstrates higher-than-average liquefaction and upstream costs for the mainstream production assets that place Australia's future at risk as the No.1 LNG provider. As noted above, the initial findings at Beetaloo do not offer evidence that will alter the competitive cost structure."[30]

[28] IEA. World Energy Outlook 2023. October 2023. Pages 20-21.
[29] Ibid. Page 139.
[30] IEEFA. Middle Arm Gas and Petrochemicals Hub: Combination of problems makes it unprofitable for business and a red flag to the public. June 2023. Page 18.

Figure 7: Global LNG cost curve – Australia's competitive complications[31]

Source: S&P Global

Oil and gas regulation

Need for stronger regulation on decommissioning oil and gas production sites

The future gas strategy must acknowledge that the gas industry in Australia will move into structural decline this decade if Australia is to abide by the science of climate change and the commitments made under the Paris climate agreement (see previous sections). Therefore, the issue of decommissioning will become a more prominent one for the industry.

There has been at least one example of a gas producer deferring its decommissioning liability, by proposing that the near exhausted gas field will be repurposed for a carbon capture and storage (CCS) facility.

Santos previously submitted plans to decommission the Bayu-Undan to Darwin Gas Export Pipeline,[32] but the company has since withdrawn this proposal. It now proposes to turn the near-depleted Bayu-Undan gas field in the Timor Sea, which is in the maritime territory of Timor-Leste, into a CCS facility that would handle 10 million tonnes (Mt) of CO_2 a year.[33] It also proposes to move CO_2 from the Barossa gas field in the Bonaparte Basin off the Northern Territory to Bayu-Undan through a 650km network of pipelines. However, Santos has not provided any costs for turning Bayu-Undan into a CCS site, and it has not released any technical study to demonstrate its plans are feasible. IEEFA submission to the Australian government's Decommissioning Roadmap Taskforce for the Australian offshore oil and gas industry stated:

"Companies should not avoid decommissioning liabilities via carbon capture and storage projects. It is important that the government and regulators scrutinise any activity to defer

[31] IEEFA. Middle Arm Gas and Petrochemicals Hub: Combination of problems makes it unprofitable for business and a red flag to the public. June 2023. Page 18.
[32] NOPSEMA. Bayu-Undan to Darwin gas export pipeline commissioning and preservation. 10 August 2020.
[33] Santos. Carbon Capture and Storage.

91 Percy Street
Warwick, QLD 4370
aus_staff@ieefa.org

decommissioning activity, such as proposals to repurpose subsea oil and gas infrastructure for carbon capture and storage (CCS)."[34]

IEEFA's submission included a range of recommendations:

"Government must be clear on the desired decommissioning outcomes and approach as these are critical to capabilities and value chain requirements. […] Australian laws must be clear on the objectives of the decommissioning work – is it to pursue the optional environmental outcome, or will it be determined by financial budgets? […] The desired outcomes will then drive the decommissioning approach. […] Decommissioning involves multiple different tasks, and guidelines on how the work can be carried out must be clear. […] Trade-offs will need to be addressed when desired outcomes are in conflict. For example, removing a whole offshore platform to land for dismantling for recycling will avoid emissions from metal production, but may produce amounts of air emissions and pollutants to the sea."[35]

"Careful consideration should be given to allowing infrastructure to stay in-situ. It appears that there is a degree of latitude that may allow firms to leave oil and gas infrastructure in-situ that may impact the marine environment. […] potential negative impacts, such as the ecological risk of residual contaminants, are unclear. Naturally occurring radioactive materials (NORM) are a class of contaminants found in some oil and gas infrastructure such as pipelines and include traces of uranium, thorium, radium, radon, lead and polonium. NORM are ubiquitous in oil and gas reservoirs around the world and may form contamination products including scales and sludges in subsea infrastructure due to their chemistries and the physical processes of oil and gas extraction. The risk that NORM from these sources pose to marine ecosystems is not yet understood, meaning that decisions made about decommissioning may not deliver the best outcomes for the environment."[36]

"It is critical that decommissioning addresses potential methane and oil leakage. Decommissioned oil and gas wells are an underreported source of greenhouse gas emissions that may partly counteract efforts to mitigate greenhouse gas emissions from fossil fuel infrastructure. Leakage of greenhouse gases from offshore wells may occur because of faulty, damaged or corroded well casings, sometimes referred to 'well integrity issues'. The leakages may also occur due to fluids migrating outside of the well."[37]

"There should be clear methodology on how decommissioning costs are estimated, both to ensure appropriate provisioning, and to prevent tax rorts since asset owners can write off decommissioning costs against any tax liability under the petroleum resource rent tax (PRRT). […] A study undertaken by Australian and Chinese researchers found that current OOGP decommissioning databases are incomplete, leading to inaccurate and subjective decommissioning cost estimation and incomplete environmental impact estimation. […] Decommissioning costs in the UK and Gulf of Mexico have been higher than planned. Recent analysis of selected offshore oil and gas platform decommissioning projects in the North Sea found that the average actual cost was about 76% more than the estimated cost."[38]

"Appropriate provisioning and legal responsibilities should be established for decommissioning costs. Australia's primary law regulating offshore decommissioning, the Offshore Petroleum and Greenhouse Gas Storage Act 2006, does not establish decommissioning financing structures, nor is there an industry or statutory fund to cover decommissioning. There should be firm

[34] IEEFA. Submission to Decommissioning Roadmap Taskforce. October 2023. Page 9.
[35] Ibid. Pages 3-5.
[36] Ibid. Pages 5-6.
[37] Ibid. Page 6.
[38] Ibid. Page 10.

91 Percy Street
Warwick, QLD 4370
aus_staff@ieefa.org

regulations around the ownership of offshore oil and gas infrastructure prior to its move into the decommissioning phase to avoid episodes such as the Northern Endeavour case, and the litigation between Australia's Cooper Energy and the Indonesia state-owned energy firm Pertamina over the ownership of Basker Manta Gummy (BMG) gas field in the Gippsland Basin. […] In 2021 [the government amended] the Offshore Petroleum and Greenhouse Gas Storage Act 2006 (OPGGS Act), that exposed past, present and potential future titleholders to liability for decommissioning costs. These costs, also known as 'trailing liability', ensure that the costs and liabilities associated with decommissioning will be borne by the petroleum industry and do not become the responsibility of government or the Australian community.[…] IEEFA recommends measures to ensure that the trailing liability requirements are implemented as they will be critical to prevent poor environmental outcomes when an asset is sold to a small company unable to cope with the decommissioning liabilities."[39]

"Government should take steps to ensure appropriate decommissioning in a rapid phase-out scenario. These issues could be particularly critical under a rapid phase-out scenario. Accelerated climate action could lead to a rapid decline of the oil and gas industry, which would dramatically change the financial situation of companies and reduce the industry's ability to meet its decommissioning liabilities. A recent study by the Sabin Center for Climate Change Law recommended four key steps governments should take to protect themselves from bearing future decommission costs: […]

1. *Create and regularly update comprehensive decommissioning plans. […]*
2. *Reexamine decommissioning security mechanisms […]*
3. *Evaluate and plan for the tax consequences of industry-wide decommissioning […]*
4. *Evaluate and modify stabilization clauses to accommodate a rapid phase-out."*[40]

Stronger action needed to reduce oil and gas methane emissions

Governments around the world recognised the need to reduce methane emissions when 150 countries launched the Global Methane Pledge in November 2021[41] at the COP26 Climate Change Conference in Glasgow. The signatories pledged to cut methane by 30% by 2030.[42]

Australia joined the methane pledge in October 2022, but did not specify a domestic methane reduction target or a plan for how it would address these emissions.[43]

The Future Gas Strategy needs to clarify how it will complement and support Australia's commitment to the Global Methane Pledge. The government will also need to take steps to improve measurement and verification of methane emissions given the suspected high level of under-reporting in the oil and gas sector, as highlighted in recent analysis by IEEFA:

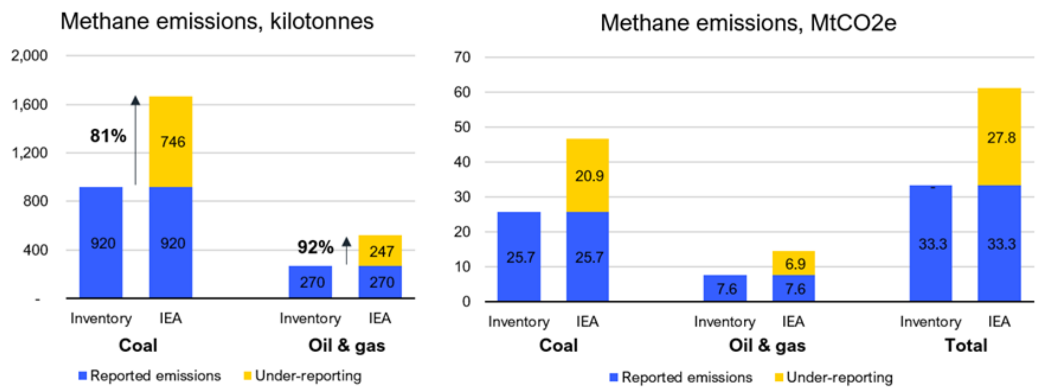
"Our analysis indicates that fugitive methane emissions from coal mining and oil and gas supply have likely been grossly underestimated to date – by about 80% for coal and 90% for oil and gas. Correcting this under-reporting would have big implications for industrial facilities covered by the Safeguard Mechanism. In order to stay within the newly introduced emissions caps, facilities would have to double their rate of decarbonisation and halve their emissions between 2023 and

[39] IEEFA. Submission to Decommissioning Roadmap Taskforce. October 2023. Pages 10-12.
[40] Ibid. Pages 12-14.
[41] US Department of State. United States, European Union, and Partners Formally Launch Global Methane Pledge to Keep 1.5c Within Reach. 2 November 2021.
[42] IEA. Methane emissions remained stubbornly high in 2022 even as soaring energy prices made actions to reduce them cheaper than ever. 21 February 2023.
[43] Australian Minister for Climate Change and Energy Chris Bowen. Australia joins Global Methane Pledge. 23 October 2022.

2030. This highlights the need for urgent action to improve methane emissions monitoring in Australia and to develop a plan to address domestic methane emissions."[44]

The under-reporting of methane emissions in Australia is the difference between Australia's official data and the estimates published by the International Energy Agency (IEA) for 2022. *"These estimates are based on 'all publicly reported, credible sources where data has become available', which includes emissions detected by satellites. We compared those estimates to the latest official national emissions inventory figures. […] For the oil and gas sector, IEA's estimates are 92% higher than the national inventory data [Figure 8]. The discrepancy corresponds to about 28 MtCO$_2$e of under-reported emissions in Australia's national inventory. This is more than 6% of today's emissions."*

Figure 8: IEA Fugitive methane emissions estimates (2022) vs National Inventory emissions data (2020-21)[45]



Sources: IEA (2022) and DCCEEW national greenhouse gas inventory emissions data (2020-21)

"It is critical to correct these underestimates as soon as possible, in particular in the context of the declining cap set on Australia's largest industrial emitters as part of the Safeguard Mechanism. […] [With corrected methane emissions] the baseline decline rate would need to be doubled from 4.9% to 9.8% a year for covered facilities to achieve the cumulative emissions ceiling of 1,233 MtCO$_2$e set by the Safeguard Mechanism reforms […]. This would require covered facilities to more than halve their emissions over a period of seven years. The only alternative would be to adjust the Safeguard Mechanism cap and increase emission reductions required by other sectors of the economy. With such strong implications, it is critical that methane emissions under-reporting is corrected as soon as possible to provide clarity on how its impact will be managed."[46]

"Methane represents about 18% of global emissions and is estimated to have contributed to around 30% of the rise in global temperatures since the Industrial Revolution. While it represents a much smaller proportion of emissions in mass, it has had a disproportionate impact on climate change. Methane has a short lifespan – around 12 years – but it absorbs much more energy than CO$_2$ while it exists in the atmosphere. Over a 100-year period, methane warms as much

[44] IEEFA. Gross under-reporting of fugitive methane missions has big implications for industry. 5 July 2023. Page 3.
[45] Ibid. Page 4.
[46] Ibid. Pages 3-4.

91 Percy Street
Warwick, QLD 4370
aus_staff@ieefa.org

as 30 times more than CO_2. However, over a 20-year period, methane warms as much as 82 times more than CO_2."[47]

The IEA has found that fugitive methane emissions from the oil and gas sectors could be cut by 80%, with at least half of that coming at no net cost:

"The technologies and measures to prevent methane emissions from oil and gas operations are well known and have been deployed in multiple locations around the world. Key examples include leak detection and repair campaigns, installing emissions control devices, and replacing components that emit methane in their normal operations. Many measures can also save money because the outlays required to deploy them are less than the market value of the methane that is captured and can be sold.

"The cost effectiveness of abatement measures varies by country, depending on the prevailing emissions sources, capital and labour costs, and natural gas prices. Based on average natural gas prices seen from 2017 to 2021, around half of the options to reduce emissions from oil and gas operations worldwide could be implemented at no net cost; implementing these would cut oil and gas methane emissions by around 40%. Based on the record gas prices seen around the world in 2022, around 80% of the options to reduce emissions from oil and gas operations worldwide could be implemented at no net cost; implementing these would cut oil and gas methane emissions by more than 60%.

"Regardless of the natural gas price, tackling methane emissions remains one of the cheapest and most effective ways to limit near-term global warming. Around US$100 billion in investment is required to 2030 to deploy all methane abatement measures in the oil and gas sector. This is less than 3% of the net income received by the oil and gas industry in 2022. Even if there was no value to the captured gas, almost all available abatement measures would be cost effective in the presence of an emissions price of only about 15 USD/tCO_2-eq."[48]

Reducing emissions from Australian gas production

CCS should not be relied on to deliver emissions reductions

Last year, IEEFA conducted a review of 13 flagship CCS projects globally comprising about 55% of the total nominal capture capacity operating worldwide. It found that failed or underperforming projects considerably outnumbered successful examples (Figure 9).[49] This underperformance was compared to the companies' own targets, not a theoretical best practice benchmark.

[47] IEEFA. Gross under-reporting of fugitive methane missions has big implications for industry. 5 July 2023. Page 3.
[48] IEA. Global Methane Tracker 2023. Strategies to reduce emissions from oil and gas operations. February 2023.
[49] IEEFA. The carbon capture crux: Lessons learned. 1 September 2022.

Figure 9: Performance of flagship CCS projects globally[50]

Carbon Capture and Storage (CCS) projects' poor report card

Project	Capacity (MtCO2 p.a.)	Performance
Natural Gas processing		
1986 Shute Creek	7	Lifetime under-performance of 36%
1996 Sleipner	0.9	Performing close to the capture capacity
2004 In Salah	1.1	Failed after 7 years of operation
2007 Snøhvit	0.7	Performing close to the capture capacity
2019 Gorgon	4	Lifetime under-performance of ~50%
Industrial sector		
2000 Great Plains	3	Lifetime under-performance of 20-30%
2013 Coffeyville	0.9	No public data was found on the lifetime performance.
2015 Quest	1.1	Performing close to the capture capacity
2016 Abu Dhabi	0.8	No public data was found on the lifetime performance.
2017 Illinois Industrial (IL-CCS)	1	Lifetime under-performance of 45-50%
Power sector		
2014 Kemper	3	Failed to be started
2014 Boundary Dam	1	Lifetime under-performance of ~50%
2017 Petra Nova	1.4	Failed after 4 years of operation

Source: IEEFA. The Carbon Capture Crux: Lessons learned. September 2022.

A more recent IEEFA analysis of Norway's Sleipner and Snøhvit projects, two of the three successful CCS examples in the earlier review, demonstrated that CCS is not an exact science, and that each project will present unique challenges.[51] This suggests economies of scale for this technology will be very limited.

IEEFA's report stated that: *"The subsurface areas of Sleipner and Snøhvit are among the most studied geological fields in both oil and gas and CO_2 storage globally. […] Despite the studies, experience and passage of time, the security and stability of the two fields have proven difficult to predict. In 1999, three years into Sleipner's storage operations, CO_2 had already risen from its lower-level injection point to the top extent of the storage formation and into a previously unidentified shallow layer. Injected CO_2 began to accumulate in this top layer in unexpectedly large quantities. Had this unknown layer not been fortunate enough to be geologically bounded, stored CO_2 might have escaped.*

"At Snøhvit, problems surfaced merely 18 months into injection operations despite detailed pre-operational field assessment and engineering. The targeted storage site demonstrated acute signs of rejecting the CO_2. A geological structure thought to have 18 years' worth of CO_2 storage

[50] Ibid.
[51] IEEFA. Norway's Sleipner and Snøhvit CCS: Industry models or cautionary tales? 14 June 2023. Page 4.

91 Percy Street
Warwick, QLD 4370
aus_staff@ieefa.org

capacity was indicating less than six months of further usage potential. This unexpected turn of events baffled scientists and engineers while at the same time jeopardizing the viability of more than US$7 billion of investment in field development and natural gas liquefaction infrastructure. Emergency remedial actions and permanent long-term alternatives needed to be, and were, identified on short notice and at great cost."[52]

Any use of CCS needs to be backed by strong regulatory protection

IEEFA found that Australia has limited protections against the failure of CCS projects:

"What the Norwegian projects demonstrate is that each CCS project has unique geology; that geologic storage performance for each site can change over time; and that a high-quality monitoring and engineering response is a constant, ongoing requirement. Every proposed project needs to budget and equip itself for contingencies both during and long after operations have ceased.

"Globally, regulation of CCS projects is both nascent and uneven. Australia, the European Union and Norway have perhaps the most advanced rules governing CO_2 injections, but their efficacy of scope and level of detail remains untested. The common features are requirements for pre-implementation plans; collection and disclosure of operational data; and post-closure containment monitoring and mitigation plans spanning decades. CCS field operators must post financial bonds and have emergency remediation plans to address contingencies if the CO_2 leaks. However, bonding requirements vary considerably among jurisdictions, from 10 years in Australia to potentially 50 years in the United States. Including long post-closure bonding periods appears to acknowledge that storage sites may not have the permanence proponents assume. Yet, at the regulator's discretion, those periods can be shortened, potentially transferring uncapped risk to the public."[53]

With many proposed large-scale CCS projects in Australia,[54] the government needs to ensure it is well protected from liability in case those projects fail and release multiple years of captured CO_2 into the atmosphere after the end of their bonding period.

IEEFA is also concerned by the Australian government's support for the Environment Protection (Sea Dumping) Amendment (Using New Technologies to Fight Climate Change) Bill 2023 [Provisions], as it will neither use new technology nor will it fight climate change.[55]

CCS has been around since the 1970s, and continues to fail to live up to the expectations promoted by oil and gas producers. Moreover, it only deals with a fraction of the total greenhouse gas (GHG) emissions, as it ignores the 85 90% of total emissions from the energy sector, which are the Scope 3 emissions released when oil and gas is burned by the consumer.[56]

[52] IEEFA. Norway's Sleipner and Snøhvit CCS: Industry models or cautionary tales? June 2023. Pages 5-6.
[53] Ibid. Pages 6-7.
[54] King & Wood Mallesons. CCS in Australia – a legal guide. March 2022.
[55] IEEFA. Submission to Inquiry into Proposed Amendments to the Environment Protection (Sea Dumping) Act. 14 July 2023. Page 2.
[56] Ibid.

91 Percy Street
Warwick, QLD 4370
aus_staff@ieefa.org

Gas transportation and infrastructure

Adapting gas networks for hydrogen or biomethane does not make financial sense

Gas distribution businesses have promoted to consumers that there is a likely future use for their networks to deliver low-carbon gases such as renewable hydrogen and biomethane.[57]

However, IEEFA analysis[58] found that significant technical and supply constraints would need to be overcome to enable this. Furthermore, if such plans were realised, consumers will be financially worse off compared to switching to electric appliances.

Hydrogen has a lower energy density than fossil gas, and when introduced into pipelines, displaces a smaller amount of fossil gas than its volumetric percentage blend implies. For instance, 10% volumetric blends of hydrogen will displace only 3% of fossil gas.[59]

Adapting infrastructure and appliances to be compatible with hydrogen incurs costs. Estimates for upgrading infrastructure to accept 100% supplies of hydrogen vary from 28% of the cost of an entirely new network[60], to more than 100% of the cost.[61]

The Australian Hydrogen Centre estimates that Victorian and South Australian customers may face collective costs of $585 million to upgrade all their appliances to accept hydrogen.[62] This figure is uncertain as such appliances do not yet exist on the mass market.

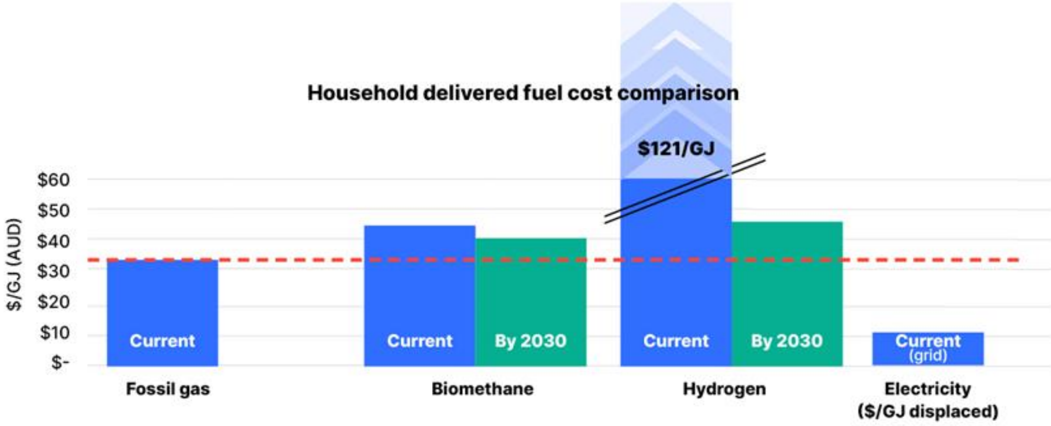
Biomethane could be more readily accepted by existing infrastructure and appliances. However, it is heavily supply-constrained. In Victoria, the likely recoverable biomethane supplies could displace only 5-12% of annual fossil gas consumption.[63] Most biomethane feedstock is located in regions that are poorly served by the state's gas transmission system.[64]

If these constraints were overcome, consumers still face paying for a fuel that is 1.3-3.7 times the cost of fossil gas, or 4-11 times the cost of electricity (Figure 10).[65]

[57] For example – AGN, Multinet, Jemena & ENA. Renewable Gas.; Energy Networks Australia. Gas Vision 2050: Renewable Gas Innovation Delivering Renewable Gas to Customers. August 2023.
[58] IEEFA. 'Renewable gas' campaigns leave Victorian gas distribution networks and consumers at risk. 17 August 2023.
[59] Frontier Economics. Indicative Analysis of Blending Hydrogen in Gas Networks – Update. May 2020. Page 4.
[60] APGA. Retail renewable gas forecast to cost customers less than retail renewable electricity. Page 1.
[61] Infrastructure Victoria. Towards 2050: Gas infrastructure in a net zero emissions economy, final report. December 2021. Page 119.
[62] Australian Hydrogen Centre. Summary report – for renewable hydrogen in existing Victorian and South Australian gas networks. November 2023. Page 18.
[63] Enea Consulting. Sustainability Victoria – Assessment of Victoria's biogas potential. December 2021. Page 2.
[64] IEEFA. 'Renewable gas' campaigns leave Victorian gas distribution networks and consumers at risk. 17 August 2023. Page 14.
[65] Ibid. Page 10.

91 Percy Street
Warwick, QLD 4370
aus_staff@ieefa.org

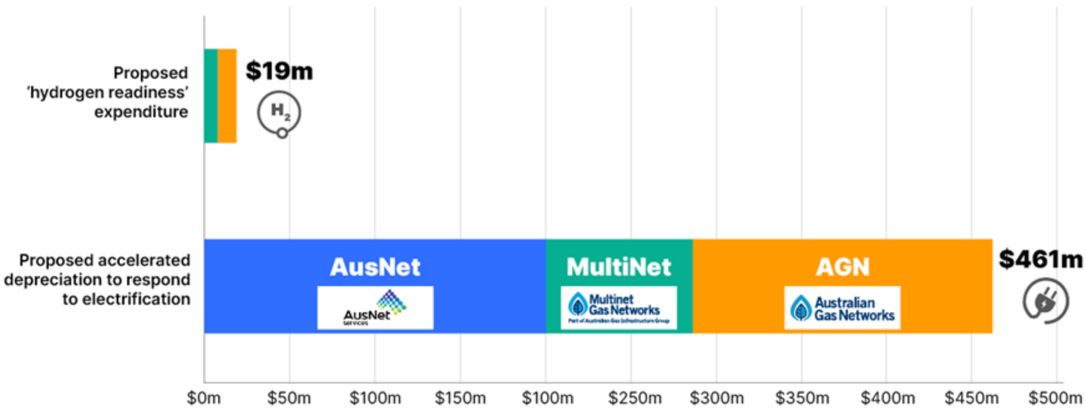
Figure 10: Biomethane, hydrogen and electricity delivered energy costs vs fossil gas[66]



Source: IEEFA. Note: Graph assumes biomethane and hydrogen can be delivered at the same cost as gas. The high relative efficiency of electric appliances means 1GJ of fossil gas can be displaced with 0.2GJ of electricity.

Gas distribution businesses are aware of the weak financial case for hydrogen and biomethane in their networks. The expenditure proposed by Victorian gas distribution networks on "hydrogen readiness" activities in their 2023-28 Access Arrangements was many times smaller than the amount they sought to recover from consumers via accelerated depreciation, in response to risks from customers electrifying (Figure 11).[67]

Figure 11: Victorian gas distribution networks' accelerated depreciation proposals vs 'hydrogen readiness' spending[68]



Source: IEEFA, based on full proposed costs for networks' 2023-28 Access Arrangement period.

[66] IEEFA. 'Renewable gas' campaigns leave Victorian gas distribution networks and consumers at risk. 17 August 2023. Page 10.
[67] Ibid. Page 23.
[68] Ibid.

91 Percy Street
Warwick, QLD 4370
aus_staff@ieefa.org

A quarter of networks' proposed hydrogen expenditure was allocated to promotional activities, to be charged to consumers. The AER noted that hydrogen-related expenditure was non-conforming with respect to the National Gas Laws.[69]

Consumers are often not empowered with accurate information about the relative economics of different household fuel choices. It is critical for governments to protect consumers from campaigns that may encourage them to make long-term investments in gas appliances that risk becoming stranded. These investments could amount to $1.5 billion a year.[70]

Plan needed to wind down gas distribution networks

The cost-effectiveness of residential electrification threatens the financial viability of gas distribution networks, which predominantly serve residential customers.[71]

Gas pipeline operators have argued that demand for their services and the useful lifetime of their assets are likely to decrease in response to electrification policies and the favourable economics of renewable electricity.[72]

AGN has stated in South Australia that, "[…] as the price of renewable electricity and storage falls further, not only will this new source of competition for natural gas, which is a fuel of choice, become fiercer, but it will start to create whole new modes of electricity production as consumers take full advantage of the distributed nature of renewable power."[73]

Queensland's Envestra network (now also operated as AGN) contended to the National Competition Council that, "Natural gas is a fuel of choice – there are readily available substitutes for all natural gas applications, particularly from electricity and LPG […] The cost of switching from natural gas to electricity or LPG is low [and …] Natural gas has no clear competitive advantage over electricity or LPG in the Queensland energy market."[74]

IEEFA analysis found that if many households electrified, gas distribution networks may be forced to pass on the cost of providing their services to a diminishing customer base, leading to unacceptable price rises in the long term.[75]

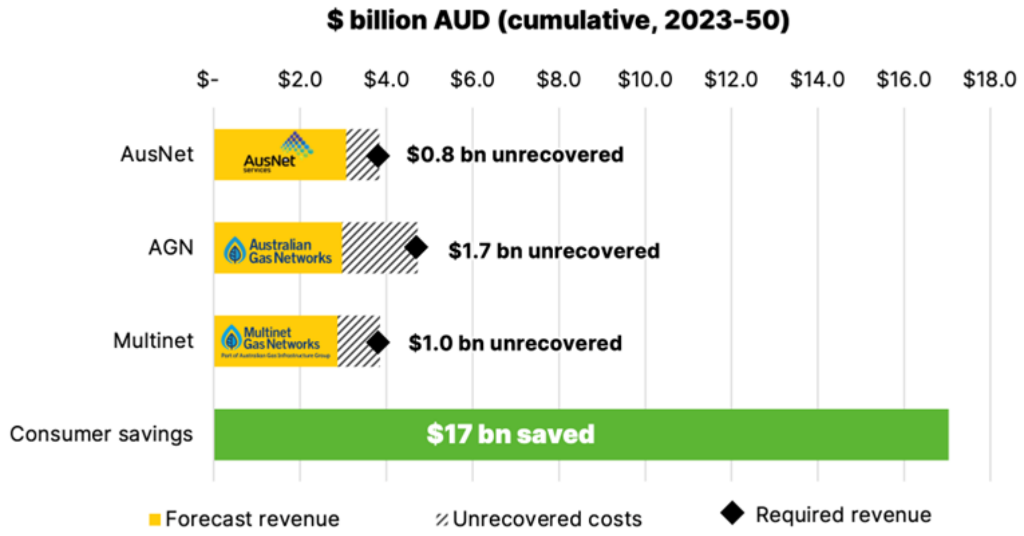
The AER has the ability to protect consumers from these price rises, and is not required to allow gas distribution networks to recover their full costs.

This would leave gas distribution networks with significant unrecovered costs. However, those costs would still be far outweighed by the economic benefits of consumers from moving to electric appliances (Figure 12).[76]

[69] AER. Final decision: Multinet Gas Networks and Australian Gas Networks Gas distribution access arrangement 1 July 2023 to 30 June 2028. Attachment 5 – Capital expenditure. June 2023. Page 7.
[70] IEEFA. 'Renewable gas' campaigns leave Victorian gas distribution networks and consumers at risk. 17 August 2023. Page 28.
[71] AER. State of the energy market 2023. 5 October 2023. Page 193.
[72] Dampier Bunbury Pipeline. Five year plan for Dampier to Bunbury Natural Gas Pipeline 2021-2025. Attachment 9.2 - Assessment of the Economic Life of the DBNGP. January 2020. Page 10.
[73] Australian Gas Networks. Future of Gas - SA revised Final Plan July 2021 - June 2026. January 2021. Page 1.
[74] National Competition Council. Light Regulation of Envestra's Queensland Gas Distribution Network - Final Determination and Statement of Reasons. 5 November 2014. Pages 14-15.
[75] IEEFA. Managing the transition to all-electric homes. 2 November 2023. Pages 14-15.
[76] Ibid. Page 5.

91 Percy Street
Warwick, QLD 4370
aus_staff@ieefa.org

Figure 12: Victorian gas distribution networks' unrecovered costs[77]



Source: IEEFA analysis assuming consumer distribution prices are limited to a 2.5% pa real price cap.

There is not a strong case for governments to subsidise these unrecovered costs, as gas distribution networks have received exceptionally high rates of return on regulated equity over the past decade, reflective of a business exposed to high risk.[78]

If customers were to leave the network in an uncontrolled manner, this could trigger an effect known as the "gas death spiral", where cost increases accelerate for the remaining users on the network. There is a high chance of these costs being passed on inequitably to renters and low-income households.

This is avoidable if governments plan now to start winding down gas distribution networks. Specifically, IEEFA recommends:

- All states and territories cease to connect new homes to the gas distribution network by 2025 at the latest, following the ACT (which will stop new connections from 2025) and Victoria (which will stop new connections from 2024);
- A clear plan is developed by governments outlining both the physical and financial decommissioning of gas distribution networks, which considers how the energy needs of the minority of hard-to-electrify customers will be met;
- A decision is made on who will bear gas distribution networks' unrecovered costs, which considers the extraordinarily high rates of return networks have historically received, and;
- That this planning starts as soon as possible, to avoid compounding locked-in costs and asset-stranding risks for consumers.

[77] IEEFA. Managing the transition to all-electric homes. 2 November 2023. Page 20.
[78] Ibid. Page 24.

91 Percy Street
Warwick, QLD 4370
aus_staff@ieefa.org

Demand reduction should be optimised before investing in new infrastructure

IEEFA's most recent report finds:

"All of [the options considered to increase gas supply to the southern states] require very large upfront capital investments for long-lived assets, which will need to be recovered, plus a profit margin, through energy bills. […]

"The two proposed LNG import facilities in Victoria, in Geelong and Port Philip Bay, are estimated to respectively cost about $350 million, and between $250 million and $499 million. This is just the cost of being able to receive LNG in Victoria. The cost of LNG itself is highly volatile. On 7 November 2023, the price of LNG in Australia was estimated at about $24/GJ. Shortly after Russia invaded Ukraine on 24 February 2022, the price of LNG peaked at about four times this price. With a probable LNG supply glut coming from the mid-2020s, the price of LNG is likely to fall. However, there remains some uncertainty about future LNG prices, with futures for the Japan Korea Marker (JKM) suggesting LNG spot prices will remain relatively high (above $15/GJ) until May 2027 and above $10/GJ out to late 2029.

"A previous IEEFA report estimated that the total cost of bringing gas from Queensland to Victoria could add up to nearly $5/GJ, and this would likely increase due to the required pipeline upgrades. For example, Australia's largest gas pipeline operator APA is spending $270 million on upgrading part of its eastern Australia gas network to carry more gas from Queensland to the southern states, particularly Victoria. It will increase winter peak capacity of APA's network of pipelines in eastern Australia by 25% through additional compression and associated works on both the South West Queensland Pipeline (SWQP) and the Moomba Wilton Pipeline (MWP). The SWQP runs from Wallumbilla in southern Queensland to Moomba in the Cooper basin in South Australia. The MWP runs from Moomba to Young in southern New South Wales (NSW). This does not reflect the full journey of the gas from the onshore coal seam gas fields in the Surat basin in Queensland to Victoria. These costs are in addition to the cost of the gas itself. While production costs in the Bowen/Surat basins are on average $4.75/GJ, recent prices offered in the past two years have generally been in line with or above $10/GJ.

"With Victoria targeting a 75%-80% reduction in its emissions by 2035, and net zero emissions by 2045, it is unlikely that new or upgraded pipeline assets would fulfill their full economic life, pushing prices higher in the short-to-medium term. For example, the operators of the Dampier Bunbury pipeline in Western Australia argued to the regulator that electrification will materially shorten its economic lifetime compared with the default asset life of 70 years."[79]

On the contrary, investments in energy efficiency and electrification drive energy bills down, and can deliver multiple additional benefits.

"Energy efficiency and electrification present many additional benefits to the cost savings for consumers. Improved thermal efficiency was estimated to deliver 10 times as much savings in health costs as in energy costs, as well as improved wellbeing. Using electric cooktops rather than gas materially reduces childhood asthma risks. Investments in energy efficiency deliver multiple economic benefits, with nearly three times as many jobs created as when investing in new fossil fuel production, along with business productivity gains and a potential positive impact on Gross Domestic Product.

[79] IEEFA. Reducing demand – A better way to bridge the gas supply gap. November 2023. Pages 23-24.

Institute for Energy Economics and Financial Analysis
ieefa.org

91 Percy Street
Warwick, QLD 4370
aus_staff@ieefa.org

While electrification would drive increases in electricity use, ensuring that gas equipment is replaced by high-efficiency electric equipment and complementing electrification with energy efficiency measures would mitigate and may even offset this impact. Enabling new electric equipment to deliver flexible demand could also yield significant system benefits and reduce energy costs for all users.

Investments in energy efficiency and electrification will reduce energy bills, while every dollar invested in new gas supply, plus a profit margin, will have to be recovered through energy bills. Increasing the focus on demand-side opportunities can help alleviate Australia's cost-of-living crisis. IEEFA urges governments and energy agencies to consider these opportunities in more detail, and properly assess the costs and benefits of investing in reducing gas demand as compared to investing in increasing gas supply."[80]

Royalties and revenues

Opportunity for more reform of oil and gas sector's tax and royalties regime

The rapid and significant increase in LNG prices in 2022 generated windfall profits for Australia's LNG exporters.

IEEFA analysis suggests that all three Gladstone LNG plants – GLNG, APLNG, and QCLNG –at least doubled their revenues in the 2021-22 financial year from roughly $10.5 billion in 2020-21 to nearly $22.5 billion.[81] Analysis by the Australia Institute similarly suggests that Australian LNG producers have earned windfall profits estimated at $26- $40 billion in 2021-22.[82] This was driven by increasing LNG prices, which resulted in the value of Australia's LNG exports rising from $30.5 billion in 2020-21 to $70.2 billion in 2021-22 despite only a marginal increase of 6% in export volumes.[83]

However, in 2021-22, Australia's oil and gas producers (which includes non-LNG producers) paid only $6.46 billion in taxes and royalties to Australian governments.[84]

This reflects a longer-term trend of declining taxation and royalty payments by the oil and gas sector. Australian government revenue data shows that the tax share of oil and gas industry revenue has been falling for the past 30 years, from about 57% in 1987-88 to just 7% in recent years.[85]

Two key reasons for this decline are changes to the Petroleum Resource Rent Tax (PRRT) Assessment Act and a shift in Australia's energy production.[86] Specifically, the PRRT has been amended over recent decades to include a number of concessions and deductions while Australia's energy production has shifted away from oil towards gas and LNG.[87]

[80] IEEFA. Reducing demand – A better way to bridge the gas supply gap. November 2023. Page 7.
[81] IEEFA. The extraordinarily profitable gas market should bring billions more royalties for Queenslanders. July 2022. Page 7.
[82] Australia Institute. War gains: LNG Windfall Profits 2022. September 2022. Page 1.
[83] Ibid. Page 2.
[84] Australian Energy Producers. Media Release: Gas sector to deliver $16 billion to governments as contribution almost triples. 20 April 2023.
[85] Australia Institute. Australia's tax system is failing to deliver the benefits of the gas boom. October 2022.
[86] Ibid.
[87] Ibid.

91 Percy Street
Warwick, QLD 4370
aus_staff@ieefa.org

The Australia Institute estimates that PRRT payments have fallen from about 19% of total revenue at the time the PRRT system was introduced to just 1% in 2019-20. This coincided with a material fall in corporate tax paid by the sector (from 16% in 1996-97 of sector revenue to just 2% in recent years).[88]

Reforming Australia's tax and royalty policy settings could potentially lead to increased tax revenue and associated social benefits. IEEFA previously estimated that if the Queensland government had revised its royalty structure for the 2021-22 financial year (in line with the revised coal royalty structure), it could have delivered $6.1 billion in royalty revenue just from the gas industry.[89] This would be about $5 billion more than the Queensland government's petroleum (gas) royalty revenue estimates for the same financial year.[90]

IEEFA acknowledges the recent reforms to the PRRT system, and further encourages government consideration of additional reform to ensure Australians reap the benefits from the extraction and use of Australia's resources.

Domestic gas supply

More focus needed on reducing demand before increasing supply

IEEFA observed that Australian energy policy has an unjustified focus on supply-side solutions:

"Several agencies consider a few demand scenarios, and then look at how the supply can meet the gap, rather than looking at what would be an optimum approach to manage both the supply and demand sides of the equation. In the 2023 GSOO, AEMO concluded that all future scenarios 'forecast the long-term need for additional supply'. In its review of the supply-demand outlook, the Australian Competition and Consumer Commission (ACCC) accepts AEMO's GSOO's central scenario's demand forecast, and therefore uniquely looks at supply-side solutions to fill the gas supply gap.

"IEEFA's submission to AEMO on updates to the ISP methodology emphasised the need for better optimisation of demand-side and supply-side solutions in its electricity scenarios. Our recent gas supply gap analysis also showed that faster and stronger demand-side action could fill the gas supply gap and avoid the need to develop new costly and emissions intensive gas fields. It showed that making small adjustments to the demand-side actions included in AEMO's 2023 GSOO Green Energy Exports (1.5°C) *scenario could eradicate the gas supply gap for the next two decades. "Accelerating action to improve energy efficiency and electrification in buildings could eradicate the gas supply gaps for the next decade while also alleviating the cost of living crisis for households. […] The rest of the gas supply gap could be filled by a small increase in industrial gas demand reduction, well within the identified technological and economic potential."*

"Both the IEA and the IPCC state that new developments in oil and gas are incompatible with the global goal of 1.5°C with no/low overshoot."[91]

[88] Ibid.
[89] IEEFA. The extraordinarily profitable gas market should bring billions more royalties for Queenslanders. July 2022. Page 8.
[90] Ibid. Page 1.
[91] IEEFA. Australia needs 1.5C aligned national energy pathways. June 2023. Page 10.

91 Percy Street
Warwick, QLD 4370
aus_staff@ieefa.org

The IPCC stated in its latest Synthesis Report that existing oil and gas developments may even need to be retired early: *"Projected cumulative future CO_2 emissions over the lifetime of existing fossil fuel infrastructure without additional abatement exceed the total cumulative net CO_2 emissions in pathways that limit warming to 1.5°C (>50%) with no or limited overshoot. They are approximately equal to total cumulative net CO_2 emissions in pathways that limit warming to 2°C with a likelihood of 83%."*[92]

The IEA stated in its latest WEO that there is no need for additional oil and gas investments even in STEPS, aligned with about 2.4°C warming. *"Today's level of investment in all fossil fuels, including oil and gas, is significantly higher than what is needed in the APS and double what is needed in the NZE in 2030."*[93]

Limiting new gas developments as much as possible by prioritising demand-side action is therefore crucial to achieving the global climate goals.

IEEFA has highlighted a number of biases embedded in energy models and scenarios used to inform energy planning and strategy. Those biases need to be addressed to properly reflect the respective costs and benefits of investments on the supply versus the demand side:

"While the AusTIMES model[94] *includes a high level of granularity on the supply side for electricity, it does not have any granular representation of the gas supply side. A fixed gas price forecast is used to inform future gas costs. This means that the model cannot properly assess the relative economic costs or benefits of changes in gas demand.*

"Indeed, increased gas production requires large, lumpy investments in long-life assets to develop new gas fields or infrastructure. Significant infrastructure upgrades are also required to enable hydrogen or biomethane to be blended into domestic gas supply. IEEFA understands that AusTIMES largely makes these decisions based on relative fuel costs, and does not include adequate evaluation of gas infrastructure requirements and their associated costs.

"To properly assess the economic costs and benefits of various gas demand pathways, it will be critical to upgrade the AusTIMES model to better represent the gas supply side and associated infrastructure, in a similar way to how electricity or hydrogen production are represented. TIMES models are highly modular in nature and offer the flexibility to represent energy conversion processes with costs. These upgrades could be completed within AusTIMES given a reasonable timeframe and cost, building upon data used by AEMO for its own gas analyses.

"Without such an upgrade, the model will have an inherent bias – underestimating the economic benefits of additional gas demand reduction, and the costs of delivering additional gas supply."[95]

"The AusTIMES model currently seems to assume that carbon capture and storage (CCS) can capture up to 90% of emissions (post combustion or process emissions). It also assumes that CCS costs can be as low as $75 per tonne of carbon dioxide (CO_2) for reservoir CCS in gas

[92] IPCC. Synthesis Report of the IPCC Sixth Assessment Report (AR6) – Longer Report. 2023. Page 24.
[93] IEA. World Energy Outlook 2023. October 2023. Page 201.
[94] The AusTIMES model informs analysis by the Australian Energy Market Operator (AEMO), and is planned to be used by the Climate Change Authority (CCA) to model sectoral decarbonisation pathways.
[95] IEEFA. Submission to the Climate Change Authority: Economic modelling of potential Australian emissions reduction pathways. September 2023. Page 6.

91 Percy Street
Warwick, QLD 4370
aus_staff@ieefa.org

extraction. These assumptions are overly optimistic compared with CCS's track record to date and need to be updated. Using unrealistic cost and performance assumptions for CCS could overestimate the benefits of the technology in contributing to Australia's energy transition."[96]

"The typical approach for scenarios is to set demand-side assumptions, and then look at how supply can meet that resulting demand, rather than looking at what would be an optimum approach to manage both the supply and demand sides of the equation. In its economic modelling, we believe that the authority should explore both scenarios that take fixed demand-side assumptions, and scenarios that take fixed supply-side assumptions. This would provide a more comprehensive understanding of the range of possible pathways and their relative economic costs and benefits. In particular, the authority should explore scenarios that limit new fossil fuel developments."[97]

Domestic demand should be prioritised over exports

While gas will have an increasingly diminishing role in future, particularly in households and in the NEM, it remains a vital input for domestic manufacturers producing goods that are commonly used in Australia (although, as noted earlier, there is scope for targeted policies to help shift many industrial users away from gas in the shorter term).[98] These goods include urea-based fertilisers relied upon by Australian farmers, explosives used in our mining industries, and plastics and aluminium manufacturing.

These producers, some of whom are energy intensive and export exposed, rely on competitively priced gas to compete with their international counterparts.[99] Australian manufacturers already face a number of disadvantages, including a relatively small domestic market and high labour costs.[100] Among the few competitive advantages Australian manufacturers have historically had is access to abundant energy at reasonable prices.[101] Sustained high gas prices on the east coast, driven by high international prices, create real risks that these manufacturers will close their operations and/or relocate to jurisdictions with more competitive energy prices (such as the U.S.). A notable example is Incitec Pivot, which closed its Gibson Island plant in Queensland, citing high gas prices as a major cause.[102]

Should this occur, these manufacturers are unlikely to return to Australia. Further, the need to import these products to replace lost domestic production will only contribute to higher emissions, particularly if Australian gas, exported as LNG, is used to make these products.[103]

There is a strong case for prioritising domestic demand over exports, particularly discretionary LNG spot exports beyond those required to meet long-term LNG contracts.

ACCC reporting shows that Queensland LNG producers have continued to export LNG volumes beyond those required to meet their contracted volumes (i.e. LNG spot sales) even as the supply outlook on the coast has continued to tighten (with diversion of gas to LNG spot

[96] Ibid. Page 7.
[97] Ibid. Page 12.
[98] IEEFA. Where to next for Australian gas? December 2022.
[99] Ibid.
[100] Ibid.
[101] Ibid.
[102] IEEFA. What's a Fair Price for Domestic Gas? December 2022. Page 9.
[103] Ibid. Page 9.

91 Percy Street
Warwick, QLD 4370
aus_staff@ieefa.org

markets contributing to the tightness of the domestic market).[104] For instance, LNG producers exported significant additional volumes in 2022 to take advantage of high international prices.[105]

LNG producers are also forecast to take more gas out of the domestic market than they supply in both 2023 and 2024,[106] when producers are likely to make LNG spot sales (for example, the LNG producers anticipate exporting 12PJ of LNG as spot LNG in the first quarter of 2024).[107]

Over the shorter term, LNG producers could continue to meet their long-term contracted volumes while ensuring the domestic market has sufficient gas to meet demand (including gas to ensure reliability in the NEM). Further, current high prices in the domestic market should ensure that these producers earn a sufficiently high return to cover their costs, with IEEFA analysis suggesting that prices of $7/GJ are sufficient.[108]

Combined with efforts to reduce demand (discussed earlier), additional domestic supply by the LNG producers could help to ensure manufacturing remains a key component of Australia's economy, and contribute to Australia lowering its emissions.

The alternative to prioritising domestic demand over exports is the development of new gas fields and associated infrastructure, or development of an LNG import terminal. As noted earlier, the development of new gas fields is inconsistent with the global climate goals. The development of an LNG import terminal, while touted as a solution to the supply gap, is likely to lead to higher carbon emissions, and further strengthen the influence of LNG prices on gas prices in the domestic market.