GRATTAN Institute

Averting gas shortages

Submission on Australia's east coast gas system

Alison Reeve and Tony Wood

Overview

Natural gas has played an important role in Australia's domestic economy for more than 50 years and contributed to our exports for more than 30 years. For most of that time, the east coast market has been domestically focused, with supply and demand in balance.

Two developments upset this balance. In 2015, liquefied natural gas (LNG) exports began from Gladstone, Queensland. By 2024, export volumes of more than 1,400 petajoules (PJ) were 75 per cent of total east coast demand. At the same time, production from the traditional south-eastern gas fields has been declining.

The current east coast gas policy framework was created to manage these changes and, particularly via the threat of direct government intervention in long-term contracts, has helped avert shortfalls since 2017.

The Federal Government published its Gas Review report in December 2025, recommending a form of east coast gas reservation and phasing out of the existing framework.

The south-east of Australia faces a more structural, longer-term gas shortfall than this framework can solve. Current projections suggest that shortfalls could emerge seasonally and then structurally beyond 2028-29. A combination of unforecast increases in demand and unplanned supply restrictions could create shortfalls even earlier.

It is clear that, unless substantial new local supply is identified or demand falls dramatically, new interstate supply will be needed, supported by transport and local storage. Although shortfalls have been avoided to date, a market-based future solution has not emerged. This is partly because industry participants hold diverse views on the nature and scale of the risk.

The Energy And Climate Change Ministerial Council has proposed that a new measure be considered under which the Australian Energy Market Operator (AEMO) would tender for infrastructure to be financially supported such that the shortfall risks could be managed.

Triggering such a measure will require robust and transparent rules. The selection criteria for the tender process will have to balance physical and market uncertainties with overpaying for insurance. AEMO is likely to err on the conservative side of risk/cost equation, and consumers will end up paying the cost.

To best achieve efficient deployment and utilisation of new infrastructure, this new measure should be complemented by a mechanism paying big gas users to reduce consumption during peak demand periods. And implementing a future gas strategy should include a clear emissions-reduction signal. This combination should address the short-term shortfall risk without creating longer-term risks of stranded assets. A sunset mechanism should be included because, into the 2030s, demand for gas is expected to fall and alternative energy supply options will become clearer.

Australia's energy and climate change ministers have recognised a significant risk and decided to act. Actions to protect against future risks involve balance, are never simple or uncontroversial, and bring their own risks.

Running out of gas in a gas-rich country would be a major policy failure and setback to a successful energy transition. It is critical that the governments get this right.

Recommendations

1. The Energy And Climate Change Ministerial Council should establish a last-resort investment supply tool, with the first rule being that it should be triggered only after a compelling assessment that the risk and cost of a gas shortfall exceeds the cost and consequences of the market intervention.
2. The Energy And Climate Change Ministerial Council should establish the tool, but ministers should not have intervention power over the way the Australian Energy Market Operator (AEMO) carries out its role. AEMO should have prescribed power to adjust the design or operating parameters of the tool in response to unintended or unexpected operational consequences or failures of the tool or its application.
3. Remuneration support contracted under this tool should be linked to the size of the financial market risk being managed, and should decline if/when that risk declines.
4. The design of the tool should be accompanied by a detailed assessment of the potential impact of its operation on the wholesale gas market.
5. There should be a formal review of the tool after three years to decide if it should continue.
6. A structured mechanism should be introduced, akin to the Reliability and Emergency Reserve Trader mechanism, to better manage the market in times of peak demand.
7. The Future Gas Strategy should be reworked, so that it provides a clear view of who will need gas, for how long, where, and how much.

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1 Introduction

This submission is by Alison Reeve and Tony Wood, of Grattan Institute, an independent think tank focused on Australian domestic public policy. Grattan aims to improve policy by engaging with decision makers and the broader community. Grattan has advocated in reports and submissions over several years for policy and market reforms that align with an effective and efficient gas market consistent with national energy and climate change priorities.

For most of the past decade, Australian governments and the gas industry have been grappling with the challenge of declining gas production from the offshore Gippsland Basin. This gas had supplied Victoria, South Australia, and NSW since the late-1960s and had been periodically supplemented with additional exploration over that time. But new supply has not kept pace with the decline, and viable alternatives have not yet emerged.

The Australian Energy Market Operator (AEMO) has identified the potential for winter shortfalls in the current decade if market conditions deteriorate, and for annual shortfalls beyond 2030.

In December 2025, the Energy and Climate Change Ministerial Council agreed to seek feedback on a draft proposal to provide AEMO with last-resort powers in the east coast gas market to help prevent structural shortfalls if the market does not respond.

In January 2026, the federal Department of Climate Change, Energy, the Environment, and Water released a consultation paper on this proposal. The consultation seeks feedback on the need for such powers and, if justified, on their form and potential costs, benefits, and risks.

This submission to the consultation draws on our previous Grattan Institute reports and submissions. It makes recommendation on the key elements of the proposal where we have relevant expertise and knowledge. In addition, we recommend complementing these powers with a mechanism to better manage the market in times of peak demand, and reworking the Future Gas Strategy to provide clearer policy direction for long-term investment decisions.

We would welcome the opportunity to engage further with the department on any of the matters raised in this submission.

2 A gas gap has been emerging in the southern states for many years

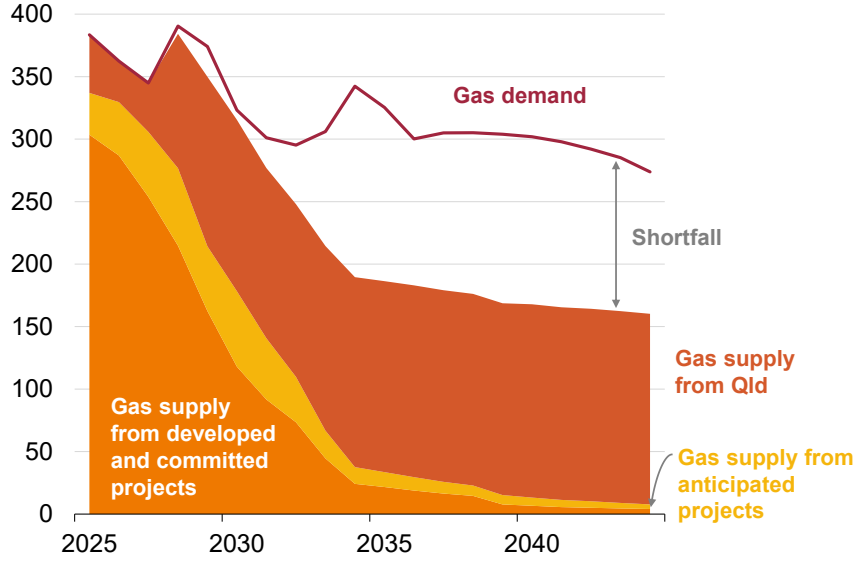
Gas production from the offshore Gippsland Basin is declining, and actions to date have not addressed this decline, although they have pushed back the timing of projected shortfalls. Recent forecasts show an annual shortfall emerging in the early 2030s (Figure 2.1).

The Australian Energy Market Operator (AEMO) currently has powers to influence customer demand and manage existing resources, but these powers are limited and intended for short-term emergencies.

AEMO's latest projections[1] indicate:

- Annual supply is projected to exceed demand until 2029. This projection includes recently committed supply and storage projects.
- There is sufficient peak supply to meet forecast peak system demand through until 2028, for mild winters and moderate demand for gas-fired power.
- Unexpected, but not unprecedented, conditions such as unforecast increases in demand for gas and unplanned supply restrictions create shortfall risks from this year.
- From 2029, a structural need for new gas supply is forecast to be required to address the projected annual shortfall gap.

Figure 2.1: The gas gap is getting bigger
Annual gas supply and demand (PJ), southern states, by source



Notes: In this submission, 'southern states' refers to Victoria, SA, and NSW. Demand scenario is AEMO's Step Change scenario.

Source: Grattan analysis of AEMO (2025).

2.1 How the gap arose

The Gippsland Basin has been a major supplier of natural gas to the east coast of Australia since the late-1960s. Its production history is marked by a transition from initial onshore oil discoveries to major offshore gas fields.

1. AEMO (2025).

The basin's story began in 1924 with the discovery of oil at Lake Bunga on the east coast of Victoria, followed by the development of offshore fields such as Barracouta in the late-1960s, which led to large-scale gas production.

For much of the current century, the production from the Gippsland Basin has been declining without being offset by new discoveries. In March 2023, the commercial director at ExxonMobil Australia confirmed the rundown in offshore supplies from the ExxonMobil joint venture with Woodside Energy, citing the decline in the number of the joint venture's producing wells from 122 in 2010 to 68 in 2023 and the expectation that the decline would continue.[2]

Since 2013, the Australian Energy Market Operator has produced an annual Gas Statement of Opportunities.[3] These reports highlight investment opportunities in gas infrastructure and reserves development, and they have been focused on identifying potential shortfalls in eastern and south-eastern Australia (Figure 2.1 on the previous page). AEMO provides this comprehensive analysis in the expectation that the market will then respond with appropriate investment decisions. But this doesn't always happen.

Several issues have converged alongside the falling Gippsland production:

- Pipelines from northern gas fields are at capacity, and additional capacity to date has been modest.
- Local storage capacity is insufficient.
- Demand is not falling at the same rate as supply.

In the next three-to-four years, seasonal shortfalls are likely to arise due to a combination of cold weather, low renewables output, and the unavailability of coal power plants. Precisely such a scenario unfolded in June/July of 2024. Although the coal and gas generators remained online, a water drought in Tasmania severely limited power supply from Hydro Tasmania. There were concerns that it may have been necessary to curtail gas demand. Fortunately, that was unnecessary, but the emerging risk was demonstrated.

Potential shortages are likely to become more frequent and last longer. The frequency of multiple days of shortfalls illustrates the nature of the emerging risk (Figure 2.2 on the following page). Pre-winter filling of available storage, expansion of such storage, and additional pipeline capacity will play a key role in avoiding these shortages.

Beyond 2029, annual shortfalls are likely to emerge.

2.2 AEMO has limited options to address shortages

As illustrated by its actions in June/July 2024, AEMO has powers to limit and/or manage potential shortage risks.[4] AEMO can issue threat notices to the gas market. These are warnings issued to industry participants when a potential risk or threat to the gas supply is identified. They alert relevant entities to the potential for inadequate supply, potentially leading to curtailments or other interventions by AEMO.

AEMO can give directions to gas industry participants to resolve an identified risk or threat. This power includes an interim compensation framework in which compensation is based on the direct financial impacts on the market participant.

2. https://www.afr.com/companies/energy/exxon-warns-of-dwindling-bass-strait-gas-20230322-p5cuce.
3. https://aemo.com.au/energy-systems/gas/gas-forecasting-and-planning/gas-statement-of-opportunities-gsoo.
4. https://aemo.com.au/newsroom/news-updates/aemo-working-with-industry-to-secure-gas-supply

The most likely subjects of directions are industrial customers. It is unlikely that households would be asked to use less gas in an imminent shortage. While coal generators remain in the system, AEMO also has the option of asking gas generators to run less.

AEMO can trade in natural gas to maintain or improve the reliability or adequacy of gas supply in the east coast gas system. AEMO has a $35 million trading fund to support this role, paid for by the state and federal governments. ($35 million is enough to buy 2.3 petajoules of gas at the current price cap).

AEMO's powers can only be applied within the physical capabilities of the market at the time. In its market reports, AEMO makes clear that those powers are not adequate to address the emerging shortfall risks.

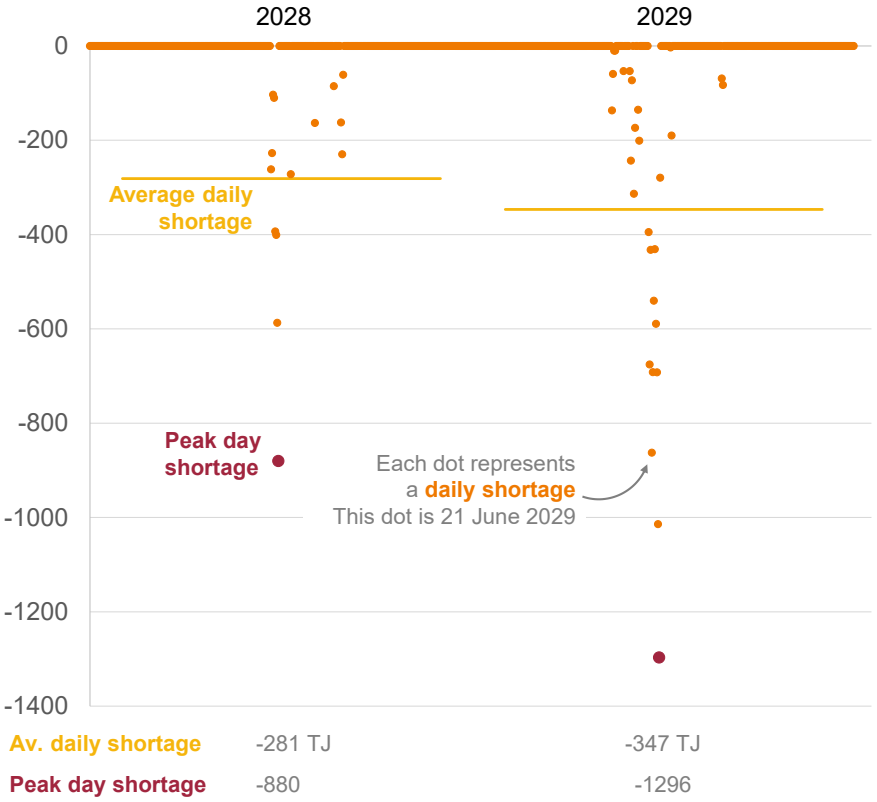
2.3 The structure of this submission

This section has shown that there are material risks of gas shortfalls in south-eastern Australia.

Section 3 describes how governments and industry have considered and responded to the shortfall risks. It includes an assessment of the options to address the potential shortfalls.

Section 4 assesses the proposed investment support tool. It makes recommendations for how such a tool should be designed and introduced.

Figure 2.2: The challenge is to meet peak demand on the peak day
Daily supply gap (TJ)



Notes: Shortage is a day where demand outstrips supply. Demand scenario is AEMO's Step Change scenario for a 1-in-20-year waether pattern. Supply scenario includes maximum southern production, South-West Queensland pipeline, and deep storage.

Source: Grattan analysis of AEMO (2025).

3 Clear market responses have not emerged

Actual gas shortfalls have not occurred in the south-east to date, but there have been times when the demand/supply balance was under significant pressure. The shortfall risk increases as local production declines and no clear market solution emerges.

Proposals for additional southern supply, LNG terminals, expanded pipelines from northern Australia, and additional southern storage have not delivered an effective commercial solution.

At its December 2025 meeting, the Energy and Climate Change Ministerial Council agreed to 'release a draft regulatory package for consultation in January 2026 to seek stakeholder feedback on a proposal to provide AEMO with last-resort powers in the east coast gas market to help prevent the realisation of structural shortfalls if the market does not respond as a final course of action'.[5] The current consultation is the first step in this process.

3.1 Supply-side responses

In response to repeated forecasts of gas shortages, the gas industry has made some moves to increase supply in Victoria and NSW, increase capacity to move gas from Queensland, and increase local gas storage. However, the industry remains reluctant to make further large investments in the face of uncertainty about falling demand and policies to address climate change.

Four actions could help addressing the gap by increasing gas supply in Victoria:

- Develop more gas supply from fields in south-eastern states.
- Increase pipeline capacity from northern states.
- Increase storage capacity in the south-east.
- Bring LNG from Queensland, the Northern Territory, Western Australia, or overseas.

The best solution (or mix of solutions) will be the one (or mix) that can be delivered quickest and with the least risk of creating a stranded asset.

3.1.1 More gas supply in the south-east

Gas producers have made modest discoveries of new gas resources off the coast of Victoria, and there have been some failed attempts.

The gas potentially available from new fields could exceed demand (see Figure 3.1 on the next page), but investing in new production is a huge undertaking.

Much of the gas currently classified as uncertain has been known about for a long time, but has not been developed, either because the reserves have not been fully assessed or investors have not been able to manage a commercially justified risk. This could be due to potentially high costs, an uncertain development timeline, or nervousness about demand certainty.

Stranded asset risk for large new supply sources is high. The social licence issues that are already affecting projects such as the Santos project at Narrabri in NSW are unlikely to decrease, adding to the risk that new fields will take longer to come online.

Exploration and development take time and are subject to sometimes uncertain approvals. Moves to tackle climate change, and moves

5. https://www.energy.gov.au/energy-and-climate-change-ministerial-council/meetings-and-communiques

towards electrification, have added a market risk that had not previously existed.

However, regulatory approvals do not seem to have been a complete barrier to offshore exploration and development. In addition to recently committed projects off the coast of Victoria, a consortium has secured a rig to drill in the Victoria's Otway Basin in 2025-26.

In December 2025, the Victorian Government released new, targeted offshore and onshore acreage for competitive tender in the Otway and Gippsland basins to address projected 2027 gas shortages.[6] Recent announcements of positive drilling outcomes by Conoco-Philips and new commitments by Cooper Energy indicate that exploration activity has been revived. Success to date has been limited[7] or poor[8].

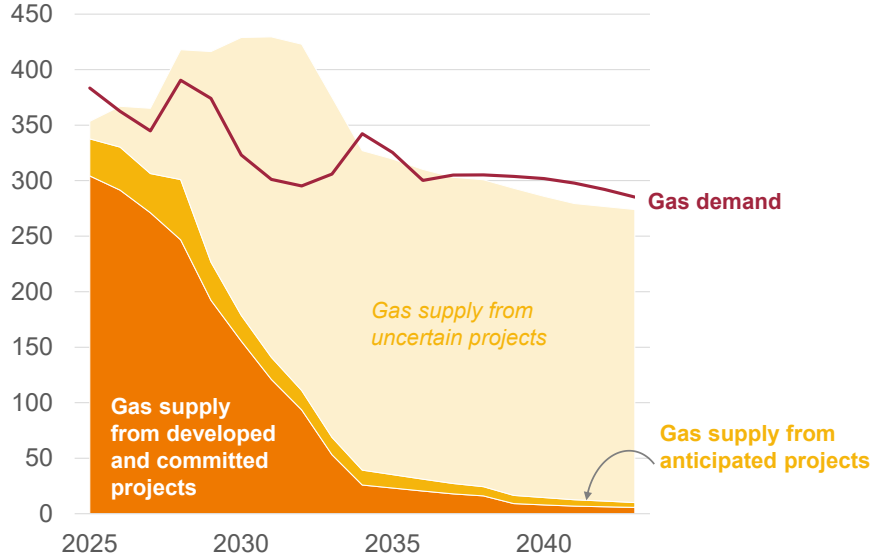
Since 2008, Santos has been working on a project to develop coal seam gas resources at Narrabri in NSW. The project, with a claimed potential to supply half of NSW's demand, has been the subject of ongoing objections from environmentalists, landowners, and AEMO does not include it as committed supply.

3.1.2 Expanded transmission pipeline capacity

APA is the major owner and operator of gas transmission pipelines in Australia. It has begun a major staged plan[9] to expand pipeline capacity to transport gas from Queensland and/or the Northern Territory to the south-east, by around 24 per cent over five years. Funding this expansion may require additional long-term contractual support.

Financiers and investors in such infrastructure will be wary of stranded-asset risk, since pipelines usually have multi-decade economic lives.

Figure 3.1: The potential for more local supply is uncertain
Gas supply and demand, southern states (PJ)



Notes: Demand scenario is AEMO's Step Change scenario. Excludes pipeline supply from Queensland and from LNG regasification terminals. Committed projects have obtained all necessary approvals, and implementation is ready to commence or already underway. Anticipated projects are projects that developers consider justified based on forecast commercial conditions at the time of reporting, and expectations that all necessary approvals will be obtained and final investment decision (FID) made. Uncertain projects are at earlier stages of development or face commercial viability or approval challenges.

Source: Grattan analysis of AEMO (2025).

6. https://consult.industry.gov.au/2025-otway-offshore-petroleum-acreage-release
7. **https://www.finnewsnetwork.com.au/archives/finance_news_network3932431.html**.
8. **https://www.finnewsnetwork.com.au/archives/finance_news_network3932431.html**.
9. **https://www.apa.com.au/operations-and-projects/gas/gas-transmission/east-coast-grid-expansion-ecge**.

3.1.3 Transport as LNG

An alternative to pipelines would be to ship gas as LNG from northern Australia to the south-east. This approach would require one or more regasification terminals and either onshore storage vessels or Floating Storage and Regasification Units (see Box 1).

Box 1: Using LNG to move gas around

LNG, or liquefied natural gas, is pure methane that has been cooled and compressed until it becomes a liquid. This makes it easier to move by ship. Australia produces about 80 million tonnes (about 4,200 Petajoules) of LNG each year,[a] all of which is sold overseas. In 2024-25, the largest export markets for Australian gas were: Japan (27 per cent), China (23 per cent), South Korea (13 per cent), and Taiwan (7.6 per cent).[b]

LNG is a better transport mechanism than pipelines for smaller volumes of gas, and for longer distances.[c] But infrastructure is required to 'regasify' the liquid natural gas – that is, turn it back into gaseous form so it can then be delivered to users. This requires either a permanent terminal or a floating storage and regasification unit (FSRU). FSRUs are ships with regasification and storage on board. When LNG cargoes are being planned, an FSRU is moored at a dedicated port terminal with pipeline connections to the main onshore gas network. The FSRU receives cargoes of LNG, brings it back to gas at ambient temperature, and sends it to users via the gas network.

Because FSRUs can be moved from location to location, they are good options for countries that need LNG only intermittently. They require minimal infrastructure onshore, and can be towed away when no longer needed – for example, if gas use falls to the point where LNG is no longer needed. This can make LNG a better economic option than a pipeline when demand is falling, because the investment can be recouped by moving an unwanted or under-utilised FSRU to a different market.

a. EnergyQuest (2024).
b. IEEFA (2025).
c. **https://pmc.ncbi.nlm.nih.gov/articles/PMC3962073/**.

Squadron Energy has constructed a terminal at Port Kembla in NSW, to tap into the Eastern Gas Pipeline, although it has failed so far to secure commercial commitments for its utilisation. [10] Viva Energy has a current proposal at Geelong in Victoria,[11] and other potential projects have been proposed for Port Philip in Victoria and in South Australia. Media reports in November 2025 said Viva Energy has delayed its investment decision on the Geelong facility because buyers are hesitant to commit to imported LNG, citing policy uncertainty, questions over future supply, and the risk of locking into multi-year contracts.

LNG has some attractions that align with the nature of the shortfall risks. Relatively small fixed capital investment is required for the onshore receival terminal, and the commitment to regasification units and LNG ships has inherent flexibility as future circumstances evolve. The stranded-asset risk is low, but there are challenges:

- Establishing and operating an integrated system to secure and transport LNG via shipping is logistically and commercially complex and will require a coordinated approach across industry and government.
- An LNG cargo needs to be offloaded all at once. If there isn't sufficient storage available (in the FSRU or onshore) to hold the gas, agreements will have to be reached for other producers in the southern states to back off production to accommodate the LNG cargo.
- A terminal and FSRU will be monopoly assets (similar to pipelines). As such, careful management and good regulation will be required to insure against anti-competitive behaviour and monopoly pricing, both of which raise prices for consumers.

10. https://www.squadronenergy.com/our-projects/port-kembla-energy-terminal
11. https://www.vivaenergy.com.au/energy-hub/gas-terminal-project

3.1.4 Local storage is being expanded

Since 1999, the Iona Underground Gas Storage (UGS)facility near Port Campbell in Victoria has been a valuable resource to supplement local production to meet peak winter demand. The depletion of the Gippsland Basin supply is leading to risks of seasonal shortfalls and increases the importance of storage. In conjunction with Snowy Hydro, Lochard Energy is expanding the Iona UGS from 570TJ/day to 615TJ/day for winter 2027 by developing and connecting depleted gas wells in the area.[12]

Snowy Hydro has committed to a 25-year plan to expand Iona UGS to support its plans for gas-fired power plants. It already has 620MW of gas peaking plants in Victoria. Such storage will be critical if gas generation is to play the expected backup role in a high-renewables power system. The expansion will not begin until after 2028 and its impact on the shortfalls risks is uncertain.

Origin Energy has agreed to support GB Energy with a project to produce about 30PJ of gas and then create a storage facility about 3km offshore in Victoria by around 2028, initially for 19PJ of gas, utilising depleted undersea reservoirs.[13] Origin has committed to use 40 per cent of that capacity and GB Energy has been looking to double the capacity of the storage.[14]

3.2 Demand-side options are limited but valuable

The risks of gas shortfalls will be lower if demand can be reduced. Improving the efficiency of gas use, switching to electricity, reducing

12. https://www.lochardenergy.com.au/our-projects/hugs/.
13. https://www.theage.com.au/politics/victoria/victoria-clears-path-for-giant-undersea-gas-storage-project-20240909-p5k8zt.html.
14. https://www.afr.com/companies/energy/vic-gas-squeeze-opens-up-1b-storage-opportunity.

demand at critical times, or using fuels other than gas for electricity generation are all options.

Permanent demand reduction (via electrification) will be necessary to hit net zero. A significant amount of household demand reduction is already built into forecasts (Figure 3.2), reflecting that this is an economic choice for most households.

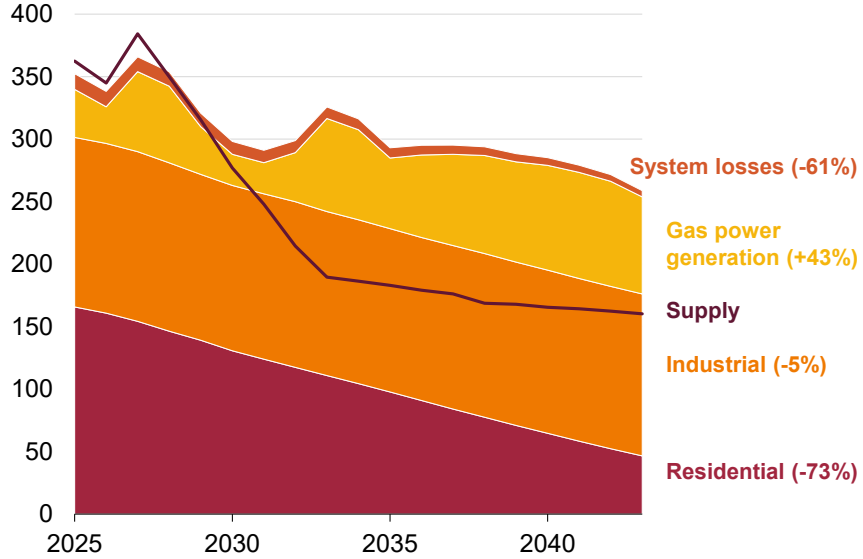
Industrial demand is not forecast to change much. For many of these users, the alternatives are not technically proven or not economic; or the users are at the wrong place in the capital cycle to consider the change. Efficiency of gas use may be a better option, although most users are likely to seek short payback times for these investments.

Demand response, particularly on days of high coincident demand for gas and electricity, is a useful tool for managing the energy system. It is already integral to the National Electricity Market and could be implemented for gas.

Gas generators could be switched to other fuels, such as diesel, biomethane, or hydrogen. But these are all much more expensive ways to generate electricity and will have consequences for electricity prices. In addition, emissions from burning diesel are much greater than burning gas, and biomethane and hydrogen are infant industries, not capable of supplying sufficient fuel within the timeframe available, though they may contribute in the longer term.

Paying attention to the demand side is useful for short-term gaps between supply and demand. But this won't be enough to address the emerging shortfalls, and the level required each year will increase as Gippsland supply declines and if no other solution emerges (Figure 3.3 on the following page). The focus should be on managing peak demand while maintaining actions to electrify.

Figure 3.2: Residential demand is expected to fall
Annual gas supply and demand (PJ and %), southern states



Notes: Demand scenario is AEMO's Step Change scenario. Supply scenario includes maximum southern production, South-West Queensland pipeline, and deep storage. Percentage demand reduction shown against 2025 levels.

Source: Grattan analysis of AEMO (2025).

3.2.1 Household and small business options

There are pathways to reduce gas demand from households by upgrading homes to electricity for heating, cooking, and hot water.

Households and small businesses save money when they switch from gas to electricity. Emissions are also reduced. While using more electricity can indirectly increase demand for gas (because of gas power generation), the extra gas demand is still less than the amount of gas saved by switching.

The forecasts in AEMO's Gas Statement of Opportunities already build in significant decreases in household gas use. Achieving this rate of switching is not impossible, but requires effort to build up supply chains and workforce.

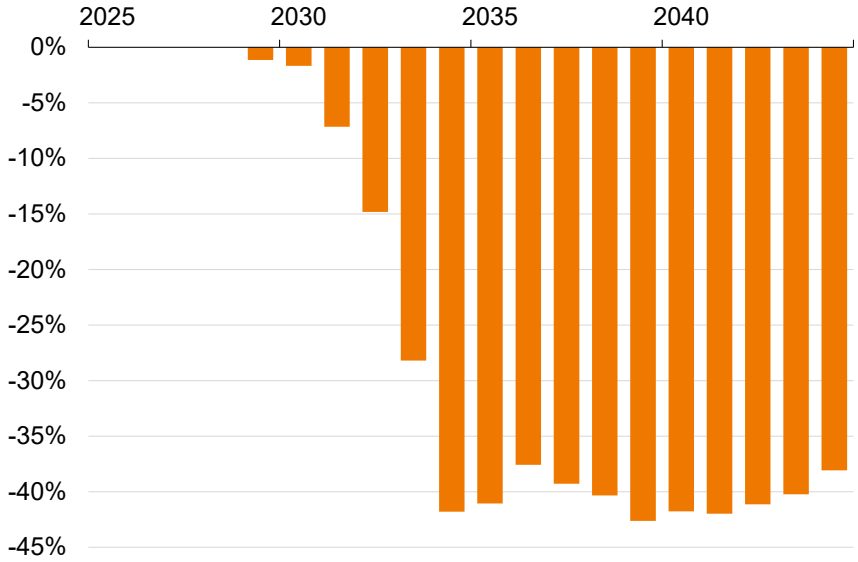
About half of households face one or more barriers to getting off gas.[15] Renters (one-third of households) do not get a choice about which appliances they use. And poorer households may not have the upfront capital required to make the switch. Unless governments make concerted efforts to remove these barriers (which they should), there is little hope of faster reductions in residential demand.

The centre of action is Victoria: 63 per cent of residential and small business gas use in southern states takes place in that state. The Victorian Government has already banned new residential gas connections from 1 January 2025, and now requires broken gas appliances to be replaced with electric ones. The impact of these moves is reflected in AEMO's forecast (Figure 3.4 on the next page), which projects residential gas use in Victoria to fall by 75 per cent over the next 25 years. Overall, the number of residential and small business gas connections is projected to fall from almost 5 million to about 1.6 million over 20 years, equivalent to 456 households or small businesses switching away from gas every day.

15. Wood et al (2023).

Figure 3.3: Reducing demand to fill the supply gap would requires steep cuts within five years

Supply shortfall as a percentage of current demand, southern states



Notes: Demand scenario is AEMO's Step Change scenario. Supply scenario includes maximum southern production, South-West Queensland pipeline, and deep storage.

Source: Grattan analysis of **AEMO-GSOO-2025**.

3.2.2 Industry options

As with electricity, a market-based demand response mechanism can assist in addressing short, sharp supply gaps. The result may be time-shifting of demand rather than reducing the total.

Industrial gas demand could be reduced through improved efficiency of gas use, electrification, or fuel substitution with biomethane, hydrogen, or diesel. We have not attempted to calculate how much gas reduction could be achieved from industrial efficiency, electrification, and fuel-switching. Sufficient public data are not available, and the pathways are more diverse and less clear than for households. Industrial equipment is more bespoke, and the economics vary from site to site.[17]

3.2.3 Market-based demand reduction

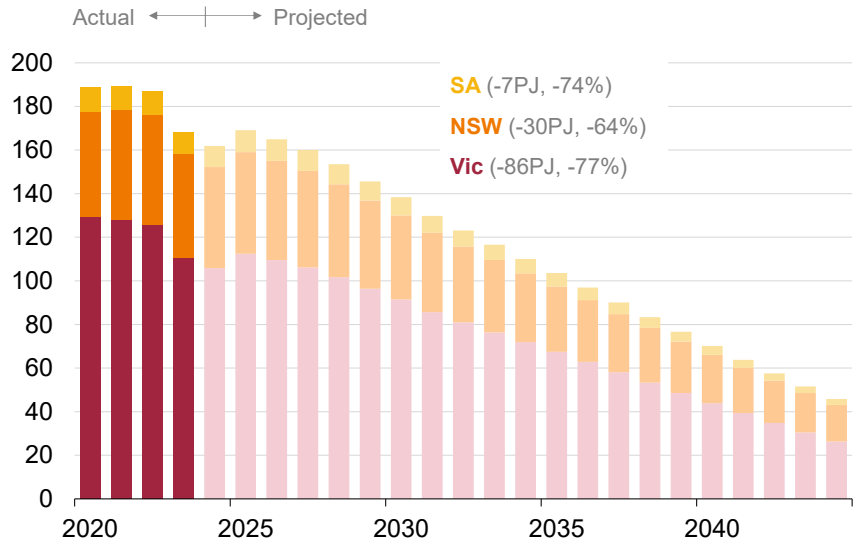
In the National Electricity Market, AEMO has a useful tool to manage peak demand called the Reliability and Emergency Reserve Trader mechanism (RERT). Under the RERT, AEMO calls for tenders each year for large electricity users who are willing to be paid to reduce their consumption on peak days.

No such mechanism exists in the gas market. AEMO can issue 'threat notices' if a supply shortfall is looming, and businesses can choose to respond, or not. If they do respond, there is a mechanism for them to seek financial compensation afterwards.

A more structured mechanism, akin to the the RERT, would give AEMO more control over the market on peak days; and would give big gas users more certainty over the impacts on their revenue of unexpected shortfalls.

Figure 3.4: Victorian household gas use is projected to decline dramatically

Actual and projected household and small business gas use, southern states (PJ)



Note: Demand scenario is AEMO's Step Change scenario.

Source: Grattan analysis of[16].

17. Wood et al (2023).

3.3 Fuel substitution

There are fuels and chemicals that could replace natural gas as a source of heat and as a feedstock for manufacturing. Their current development timelines mean they are not well-placed to meet the looming gas shortfalls.

3.3.1 Biomethane and hydrogen are not immediate options

Two forms of gas have the potential to replace fossil-based methane in its current applications, but without adding to greenhouse gas emissions. Biomethane is produced from organic matter such as agricultural or landfill waste. This means it can be classified as a renewable gas when combusted, since those emissions would have occurred anyway. Green hydrogen, produced using renewable electricity to electrolyse water, can also be used as a combustion fuel. It has the additional benefit of potentially replacing methane in the manufacture of petrochemicals, fertilisers, and explosives.

If the potential of these renewable gases could be commercially realised, even in a subset of current natural gas applications, they would relieve the pressure on the gas market and help avoid or manage the potential shortfalls.

But it is not as simple as switching one gas for another. The cost of green hydrogen is proving to be a greater obstacle than had been envisaged a few years ago. Many proposed projects have been abandoned or deferred until the cost comes down and/or the demand for green hydrogen-based products emerges. Biomethane is relatively expensive and its supply looks likely to be a limitation. It is likely to be much more valuable for gas uses where electrification is not a technical possibility and hydrogen is not an economic option.

In summary, there are economic, technical, and logistical reasons why widespread substitution of renewable gas for natural gas won't be an effective solution to the gas shortfall risk, at least in the next few years.[18]

3.3.2 Diesel is a bad option

'Flexible gas' power stations (open-cycle gas turbines and reciprocating engines) can burn diesel instead of gas. Most of the gas capacity in the NEM is flexible, but most gas is consumed by 'mid-merit' power stations (combined-cycle gas turbines and steam sub-critical turbines). Replacing gas with diesel would require using flexible gas power stations more and mid-merit gas power stations less. Diesel is also easier to store and stockpile.

But diesel is a higher-emissions fuel. Using diesel in flexible gas power stations would add 20 million tonnes to Australia's emissions over the coming two decades (Figure 3.5 on the following page).

A further challenge is that diesel costs almost three times as much as gas for the equivalent amount of energy ($33.50/GJ on current prices).[19] Because the electricity market dispatches the lowest-cost generation first, the only way a diesel generator would contribute to the electricity mix would be if there was no other option available to meet electricity demand.

3.4 The big gas-using states are caught in a dilemma of their own making

Both NSW and Victoria have responded to a lack of social licence for expanded gas production by slowing down or stopping approvals for projects. But at the same time, they have not made enough effort to reduce the use of gas in their states.

18. Ibid.
19. Based on national average retail price, week beginning 29 January 2026 (**diselpriceref**), less fuel excise.

In 2012, an administrative moratorium was placed on all onshore gas exploration and development in Victoria. In 2017, the Victorian Government passed legislation that meant fracking and coal seam gas extraction were permanently banned.

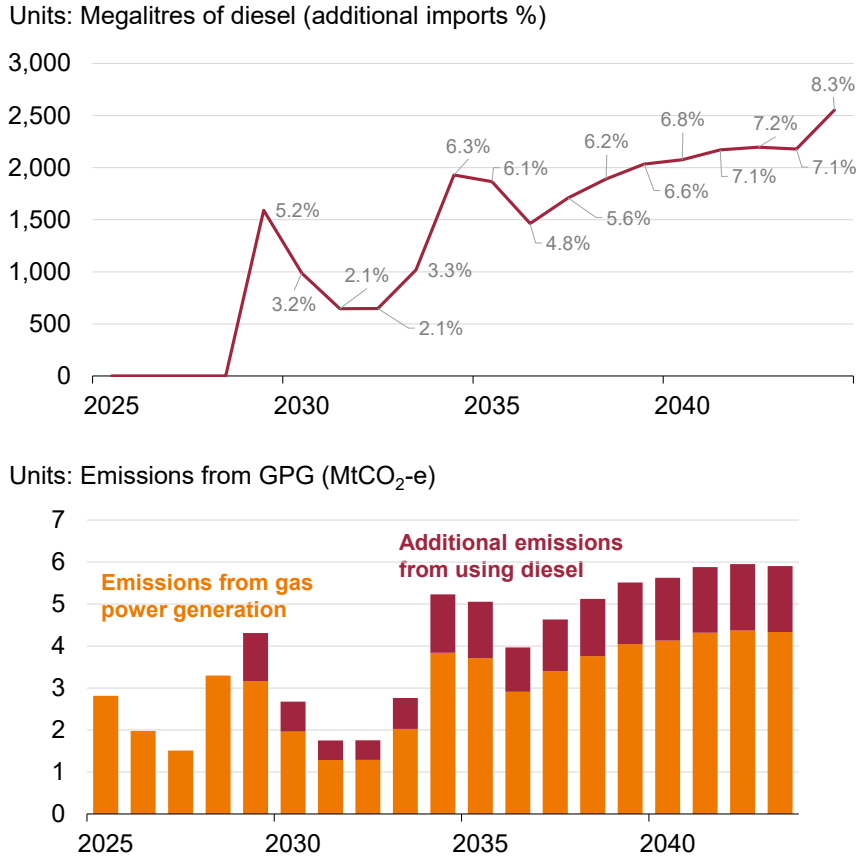
In June 2020, the Victorian Parliament passed the Petroleum Legislation Amendment Act 2020, which allowed for the restart of onshore conventional gas exploration and production. There has been no substantial progress as a result of this change, presumably because the industry sees little prospect of geological success.

Victoria has moved to start phasing out gas. It has produced a Gas Substitution Roadmap,[20] but has not yet named a target date.

The NSW and South Australian governments have displayed little interest in sustained policy to drive significant reductions in gas use, though both have taken some action, including trials to test the potential for renewable gas, either as biomethane or green hydrogen.

Local governments have been keen to move. For example, from January 1, 2026, new residential developments within the City of Sydney will be required to install electric cooktops, ovens, and indoor heating and cooling systems.[21]

Figure 3.5: Sustained substitution of diesel for gas should be avoided



Notes: Calculations assume that on days where a gas supply gap exists, mid-merit generators do not run and their contribution to electricity supply is picked up by flexible generators, using diesel.

Sources: Grattan analysis of **2024 ISP and 2025 GSOO** *(gas generation and consumption),* **others on diesel**.

20. https://www.energy.vic.gov.au/renewable-energy/victorias-gas-substitution-roadmap.
21. https://www.realestate.com.au/news/landmark-sydney-gas-ban-to-make-all-new-residential-homes-fully-electric/.

4 Here's what should happen next

Companies are undertaking exploration in Victoria, onshore and offshore Victoria. But, as described earlier in this submission, the expectations of volume do not align with the accelerating decline in the existing fields. The Consultation Paper has identified expanded local storage, additional pipeline capacity from the north, and shipping LNG as options to address the risk of shortfalls. The current market and policy environment is struggling to deliver a commercial solution from these options and that has led to the proposal for some form of risk-based government support.

The experience in the market to date suggests that the initial years of operation in a period of seasonal and unpredictable shortfalls create a major hurdle for straightforward commercial arrangements to support the costs of additional infrastructure. Government support may be justified to meet the cost shortfall, although that support should diminish over several years as utilisation increases. The cost of such support should be recovered from the market.

There are options for a commercial model. A buyer consortium would be preferable to direct government underwriting in the market, but such a structure requires an unlikely level of industry cooperation. Imposing a gas trading role on AEMO would be a major distortion of its primary market role and require a financial and market skill set it does not currently have. In principle, the proposal for AEMO to tender for infrastructure, as described in the Consultation Paper, is a better option.

The best solution during the next five-to-10 years is a combination of government risk-based underwriting of the early-stage commercial risk associated with additional infrastructure, an active demand-management response as additional risk protection, and a clear strategy to move away from widespread gas use in the longer term.

4.1 Key elements of the tool to promotoe long-term reliability and supply adequacy

4.1.1 Clear rules

The risks of south-east gas shortfalls is clear enough to justify establishing a tool to promote long-term reliability and supply adequacy. Gas consumers are being insured against the risk of gas shortfalls and the cost of that insurance should be borne by them. However, the cost should be proportional to the risk.

The creation of the tool as insurance does not mean it will be triggered. The Energy And Climate Change Ministerial Council should set the rules/criteria that AEMO would use to trigger and implement the tool as a last resort. They should include:

- A defined notice period, e.g. six months, for triggering the process and setting a forward planning period for which the shortfall risk is assessed. this could be a range of two-to-five years, with some flexibility for proposals.
- The risk criteria that AEMO must apply to trigger the tool such as probability of forecast demand and supply volumes over the forward planning period. Market soundings should be required to test the possibility that AEMO's action could deter alternative market solutions.
- The level of remuneration support and the term of a contract under this process. These are the key determinants of financial exposure and the risk being borne by the project proponent and AEMO on behalf of consumers. Once determined they should be firm limits.

- The assessment criteria for project selection. These would include risk-based costs, support timeframes, and risk-sharing mechanisms.

- A formal review of the tool after three years to decide if it should continue.

4.1.2 A remuneration off-ramp

The revenue provided to the tool proponent under the contracts should be linked to the initial and ongoing market risk. If/when the asset utilisation increases above an agreed level, the remuneration should decline.

4.1.3 Market impact

Interventions by governments or their agencies in the market carry multiple risks to the efficient operation of the market and should be a last resort. Direct or indirect subsidies that shift the balance in a market towards or away from market participants must be assessed ahead of the establishment of the tool and in its operation. The rules must be transparent, and reviewed if unintended consequences emerge.

4.1.4 Assessing the potential for monopoly behaviour

The Australian upstream gas industry has been exposed to real or perceived anti-competitive behaviour over many years. Gas pipelines and large gas processing facilities are examples. The owner/operator of a facility receiving remuneration under the proposed new tool could be in a position of monopoly power. This risk should be reviewed and assessed by the ACCC before proceeding.

4.1.5 Consistency with other gas market policies

The federal government has released its Gas Review Report[22] that includes setting up a form of domestic gas reservation scheme. The Department of Climate Change, Energy, the Environment, and Water has since opened a public consultation on the detail of the scheme design. The report also includes an important recommendation that the government ensure coordination by continuing to support the work on the new tool to promote long-term reliability and supply adequacy.

4.1.6 The role of energy ministers

The role of ministers should be to agree to the principles and design of the new tool. Allowing for ministerial intervention in the triggering and/or operation of the tool would create an additional and unnecessary market risk. The Energy And Climate Change Ministerial Council should establish the tool, but ministers should not have not have intervention power over the way AEMO carries out its role.

AEMO should have prescribed power to adjust the design or operating parameters of the tool in response to unintended or unexpected consequences or failures of the tool or its application.

4.2 Complementary government actions

4.2.1 Market-based demand response

Alongside an new tool, a demand-response mechanism should be designed and implemented in the gas market to address short-term shortfall risks.

The scheme should be operated by AEMO, and the costs recouped from all gas users, proportionate to their gas use. Governments should do further work to determine:

22. https://www.dcceew.gov.au/energy/markets/gas-markets/gas-market-review.

- How much gas could be available, and at what cost.
- Whether location of peak demand reduction should be a criterion for scheme participation.
- How much notice gas users would need.
- What would be the impact on the gas contract market.

It would be useful to seek expressions of interest from large users, including indicative payments and volumes. This feedback should be used to assess the price impacts before proceeding with a full-demand response scheme.

If proceeding to a full scheme, AEMO could run annual or seasonal tenders based on its Gas Statement of Opportunities forecasts. The Reliability and Emergency Reserve Trader mechanism used in the National Electricity Market should be used as a template.

4.2.2 Future gas policies

The federal, state, and territory governments have policies that relate to the gas market, and these all must evolve, ideally in a coordinated fashion.

The Federal Government's National Net Zero Plan is built on sector plans. Those plans should outline where gas does and does not have a future in each sector. The current versions do not provide such a clear picture.

The Future of Gas strategy should be reworked to include defined outcomes and milestones, with policies to achieve them. Vague statements such as 'gas will be an important part of our energy mix for many years' are not helpful. What is needed is a clear view of who will need gas, for how long, where, and how much. Without this information, no one – governments, industry, consumers – can make good decisions. An upcoming Grattan Institute report will provide recommendations on what that rework should look like.

State and territory governments should set dates for an end to household and small commercial gas use. About 50 per cent of households face one or more barriers to electrification. Governments should put policies in place to help those households to make the switch.[23]

State and territory governments should also develop an equitable framework for dealing with the safety, reliability, and financial viability of the gas network during the transition. This framework should be developed with and provide future guidance for the Australian Energy Regulator.

It is unrealistic to think consumer choice alone will deliver this goal. And ad-hoc consumer choices to electrify will drive up costs for remaining gas users (including industry) because networks will be under-utilised.

23. Wood et al (2023).

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