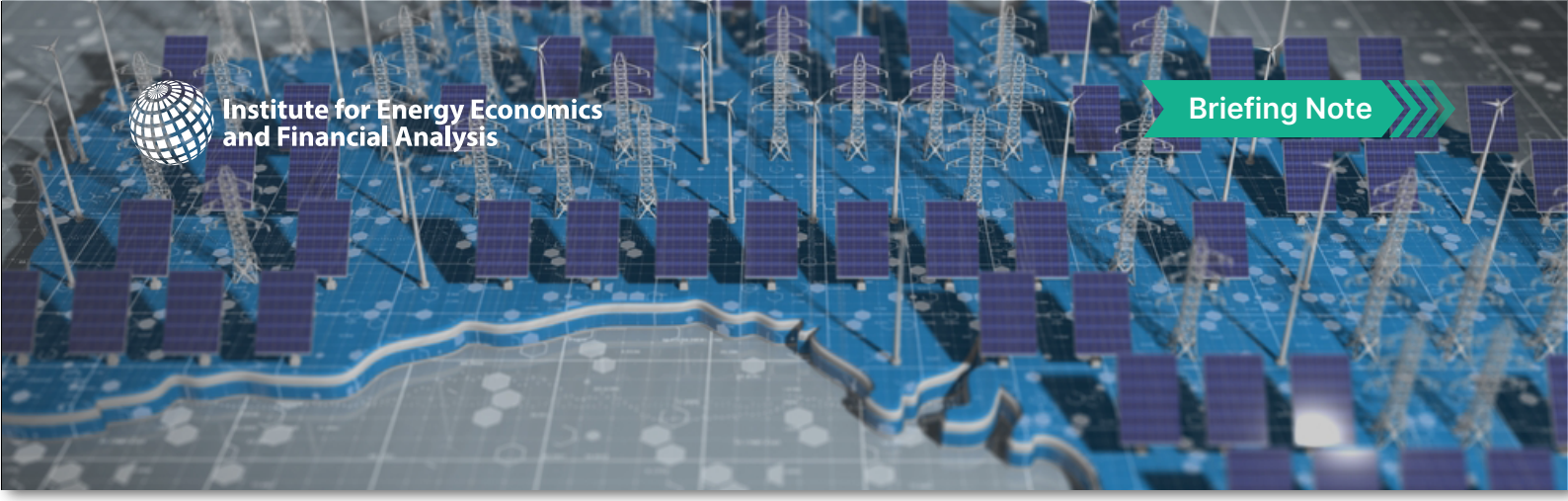


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# Improving energy affordability aligns with net zero

- *A review of recognised pathways to improve energy affordability in electricity and gas shows that all the key opportunities are either aligned with net zero or neutral to climate policy outcomes.*
- *Significant investment is unavoidable to replace Australia's ageing electricity generation and network assets, and deploying renewables, transmission upgrades and storage is the lowest-cost option for new-build electricity generation.*
- *Focusing on energy efficiency, electrification and distributed energy resources offers the best pathway to reduce energy costs for households, reducing net energy bills by up to 67%.*
- *Fixing inefficient markets and regulation and increasing competition could also offer immediate and lasting relief from rising energy costs, irrespective of the government's climate policy.*

## Introduction

Discussions about Australian energy policy have long been marked by a tendency to cast emissions reduction targets as incompatible with energy affordability. The latest example came on 13 November, with the opposition Liberal Party's decision to abandon its commitment to net zero.

Renewables are often portrayed as a high-cost option that has been responsible for recent electricity price increases, while coal and gas generation are presented as lower-cost pathways. In this briefing note we review the existing evidence, based on research by IEEFA and other organisations, on the lowest-cost energy options and the largest opportunities to improve energy affordability, and we assess the extent to which they align with Australia's net zero ambitions.

## Electricity supply

### *Investing in new electricity assets is unavoidable, the question is which ones*

Historically, Australia has relied heavily on coal for its electricity. In 2000, coal represented 90% of electricity generation in the National Electricity Market (NEM). However, coal generation peaked in 2008 and has since declined by a third, mostly driven by a 26% decrease in coal capacity as aging coal plants retired. Since 2000, 13 coal power plants have closed, at an average age of 42 years.

On average, the remaining 15 coal power stations in the NEM are just four years away from this retirement age. Based on announced retirements as of 2024, three quarters of the remaining coal capacity will be retired by 2040, and according to the Australian Energy Market Operator (AEMO), there could be no coal plants left open in the NEM by then.

In Western Australia (WA), the state's largest coal power station is already partially retired, with the plant's newest unit turning 40 years old in 2025. The state government is planning to retire all of its coal plants by 2030.

Networks face a similar situation. In 2020, the Australian Energy Regulator (AER) found that "25 per cent of distribution poles are more than 53 years old, with a sizable clump of poles installed during the 1960s. Poles this old often start to fail, leading to reliability issues." The AER's report identified that 50% of poles had been installed more than 40 years ago. When it comes to transmission, the report found that 75% of operational transmission towers were built before 1989.

In addition to the need to replace old assets, there is also a continued need for new investment to connect new customers as the population grows.

So the question today is not whether we need to make new investments in electricity generation, but what options are most cost-effective.

### *Renewables are the lowest-cost technology for new-build electricity generation*

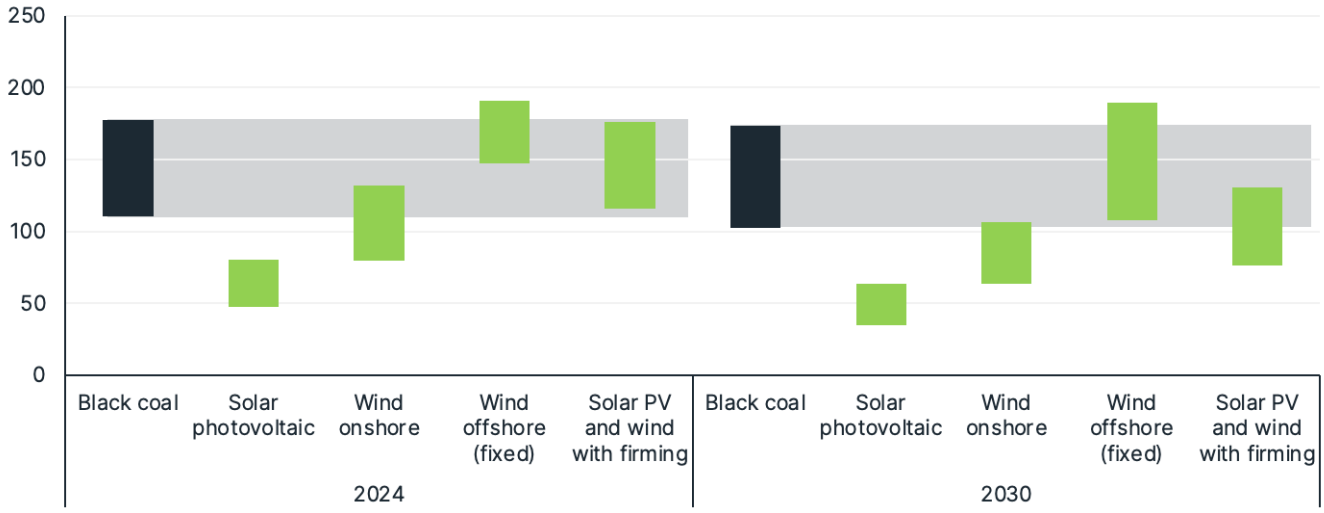
Since 2010, the cost of renewable energy technologies has plummeted. On a levelised cost of electricity (LCOE) basis, renewables are now the most cost-competitive option globally for new electricity generation, with costs about 40-50% lower than the nearest fossil fuel option.

The lowest-cost technologies are solar and wind, both variable sources of electricity, with the best resources often located in different areas to existing power plants. As such, they require additional investments to integrate them into existing energy systems, such as new transmission lines, firming capacity, and additional investment to ensure system security.

CSIRO estimates that integration costs add $48-64 per megawatt-hour (MWh) in 2024 (compared with about $90/MWh of renewables generation costs), and $23-40/MWh in 2030 (compared with about $70/MWh for renewables generation), depending on the share of renewables in the electricity system. The largest contributors to integration costs are transmission and battery storage, respectively representing about 50% and 30% of total costs on average. Additional costs such as synchronous condensers (to replace the inertia currently provided by coal generators), are minor in comparison, representing about 3% of integration costs in 2024 and 8% in 2030.

When considering the full cost of renewables including integration costs, CSIRO found that new renewables will be materially cheaper than new coal in 2030, with costs already on par in 2024.

**Figure 1: Levelised cost of electricity (LCOE) of coal and renewables, $/MWh**




*Source: CSIRO.*

These findings are echoed by energy sector leaders. The Australian Energy Council (AEC), the peak industry body for energy companies, recently surveyed its members and found that CEOs "remain committed to supporting net zero on the premise that the least cost, lowest impact pathway is an energy system dominated by renewables and firmed by battery storage, gas and pumped hydro".

The low cost of renewables is reflected in its rapid global expansion. Ember found that 99 countries – more than half of all countries in the world – doubled their electricity production from solar power in the last five years. The International Energy Agency (IEA) forecasts that renewables will become the largest global energy source by 2030, supplying almost 45% of electricity generation.

In Australia renewables already accounted for 39% of the electricity mix in 2024, 83% of which were solar and wind. Of nearly 1,000 electricity projects in the NEM pipeline, 96% are renewables or storage projects. Many of the projects are owned by private sector entities, demonstrating a significant private sector appetite to invest in renewables and storage.

There have been delays in the deployment of renewables, and both delays and cost overruns for transmission and large pumped hydro projects, which have put pressure on the electricity system. However, it is worth remembering that such issues are common with any type of large capital project and are not confined to renewables and enabling technologies. In a 2022 study of more than 500 large global capital projects, McKinsey and Company found that "cost overruns, on average, ran at least 79 percent relative to initial budget estimates, while delays averaged out to 52 percent compared against initial time frames."

### *Increasing generation from fossil fuels would drive costs up*

There are costs and risks associated with keeping ageing coal plants in the system for longer – they experience more breakdowns, leading to reliability risks and spikes in wholesale electricity prices. We found that the coal plants that have closed in the NEM since 2000 only had two thirds of their capacity available on average in the years before they retired.

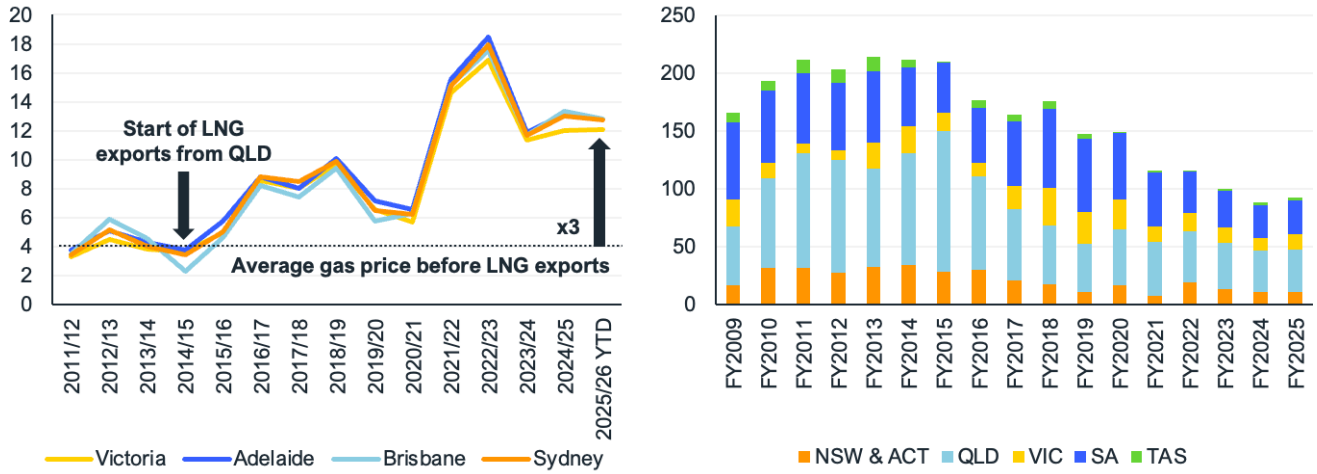
Refurbishing old coal plants to keep them going for longer is costly and carries risk. Proposed or completed refurbishments at Muja AB, Hazelwood and Liddell saw project costs ranging from

$400 million to $1.3 billion (in 2025 dollars). Muja AB went ahead with the refurbishment and saw costs triple from original expectations; the plant shut just three years after the refurbishment was finished. The Hazelwood and Liddell refurbishments were deemed too costly and complex to proceed. As coal power plant equipment ages, it becomes more prone to catastrophic failures and accidents. This has been observed in historical fires at Hazelwood, Yallourn, Morwell and Northern, and in technical issues that led to dangerous explosions at Muja AB, Yallourn and Hazelwood.

It is worth noting IEEFA has not conducted a full analysis of refurbishment costs at all coal plants in Australia, and some younger plants may require lower capital investments to be extended.

Gas generation is not cost-effective in eastern Australia. Gas consumption in the NEM fell by 57% between its peak in FY2012-13 and FY2024-25, as the share of gas generation in the NEM dropped from 12% to 5%. Since the start of LNG exports in Queensland in 2015, wholesale gas prices tripled due to their increased exposure to international markets, and gas generation has become increasingly uncompetitive with cheaper alternatives such as renewables. On average over FY2024-25, AEMO's quarterly energy dynamics reports show that gas power plants set the wholesale spot price in the NEM at about $200/MWh, well above the average wholesale price of $131/MWh. In comparison, solar and wind projects set the price at negative levels on average.

**Figure 2: Eastern Australia wholesale gas prices, $ per gigajoule (left); and gas use for NEM electricity generation, petajoules (right)**




*Source: AER.*

AEMO expects gas will only have a very small role to play in the future NEM, representing just 2.6% of generation across 2030-2050 in its central scenario. This corresponds to an average utilisation rate of just 7% between 2024 and 2050. In addition, global shortages have made it difficult to buy gas turbines – with costs tripling, and manufacturers advising developers to plan seven to eight years ahead for turbine procurement.

New coal generation is already on par with new renewable generation including integration costs and will soon be more costly. There are no new coal projects in the NEM projects pipeline. The world is fast shifting away from coal. For example, there have been significantly more stalled projects than new proposals in South-East Asia since 2016, with Malaysia, the Philippines and Vietnam all committing to phasing out coal or stopping building new coal. While China is still building a significant amount of new coal plants, this is not expected to lead to increases in the volume of coal generation, as the utilisation rate has already dropped by about a third over the last 15 years to around 50% and is expected to keep falling.

Even looking backwards, Griffith University studied what would have happened to wholesale electricity prices if Australia had only built coal and gas generation since the mid-2000s, rather than renewables. It found that wholesale prices would have been about 30-50% higher.

### What has been driving electricity prices up in recent years?

IEEFA recently reviewed some of the main drivers of increases in retail electricity prices in eastern Australia. We found that:

- The two largest components of electricity prices are the wholesale price of electricity and network costs (comparable in size).
- Key recent drivers of increases in wholesale electricity prices have been increases in gas and coal prices, as well as coal outages driving price spikes.
- Renewables have been putting downward pressure on wholesale prices, with periods of high renewables highly correlated with low wholesale prices.
- Network costs have recently risen in the AER's Default Market Offers due to inflation, interest rates and new expenditure including transmission.
- There have also been significant recent increases in the retail cost component, due to increases in costs such as bad and doubtful debt.

Delays in the rollout of renewables and transmission are also often cited as driving prices up as they increase the reliance on ageing coal power plants and more costly alternatives such as gas.

It is worth noting that while significant investment in new transmission lines is being made to connect new renewables, at this stage transmission only represents a small share of network costs. Transmission (high-volume, long-distance) revenues only represent about 20% of total network revenues, with distribution (local) revenues dominating. Transmission projects have recently seen cost increases, and recent Default Market Offers have indicated transmission is one factor driving network cost rises. Keeping network costs efficient will be crucial in ensuring energy affordability.

### *Nuclear or carbon capture and storage would be highly costly*

Nuclear would be significantly more expensive than new coal plants or renewables. IEEFA reviewed a range of recent nuclear reactor construction projects in countries with economies comparable to Australia. We found that the cost of electricity generated from nuclear plants would likely be 1.5 to 3.8 times the current cost of electricity generation in eastern Australia.

Under plans proposed by the opposition Coalition, introducing nuclear to Australia's energy mix could increase household electricity bills by $665/year on average. The Coalition anticipated that the plants would operate commercially with high capacity factors. The international projects that IEEFA reviewed experienced significant cost overruns (blowing out by a factor of between 1.7 and 3.4) and construction delays, and put the companies involved in financial difficulty.

Carbon capture and storage (CCS) is also unlikely to support energy affordability, given its high cost and unreliability. In 2022, IEEFA conducted a review of 13 flagship CCS projects across various sectors and countries, representing more than half of total operating capacity. We found

that the majority of projects failed or underperformed. Only three projects were deemed to be successful – albeit against their own targets.

IEEFA subsequently assessed two of those "successful" CCS projects in detail: Sleipner and Snøhvit, both in Norway. We found that they both faced significant challenges linked to local geology, indicating CCS is unlikely to ever achieve significant economies of scale.

CCS is also prohibitively costly. Its cheapest application is expected to be in the gas processing sector. However, the world's largest commercial-scale CCS project, at the Gorgon LNG plant in Australia, has been plagued by technical challenges. Cost overruns and underperformance resulted in a cost of $222 per tonne (t) of carbon dioxide (CO2) captured in 2024.

These issues are likely to be even worse in the power sector. For a coal power plant, the costs just for capturing the carbon are expected to be about $75-100/tCO2 – compared with less than $15 for gas processing. A conservative total cost of about $200/tCO2 would translate to about $150-200/MWh, just for the CCS component associated with a coal plant.

### *Opportunities to lower the cost of the current transition*

Further efforts to accelerate the deployment of new renewable, transmission and storage assets, and to ensure that network expenditure and revenue is kept to efficient levels, would help to put downward pressure on electricity bills. In the AEC survey, energy CEOs stressed the importance in particular of shortening approval timelines for renewables and storage projects, and of ensuring network spending is timely and efficient, reducing or avoiding network spending where possible.

Modelling by consulting firm Jacobs for the Clean Energy Council found that "relying on coal power and significant amounts of expensive gas generation for longer would increase the average household bill by $449 a year in 2030 and $877 for a small business." Modelling by NEXA Advisory found that delays to renewables, transmission and storage deployments could lead to an additional 2.8 gigawatts of gas capacity being required, increasing annual gas consumption by up to 107 petajoules (PJ) by 2030, and increasing total wholesale electricity costs to 2050 by up to $116 billion.

One approach to reduce deployment delays could be to better utilise distribution networks while waiting for the construction of new transmission. Distribution networks are currently materially underutilised, with a utilisation rate of just 42% in 2022.

Network costs account for almost 40% of a typical household's energy bill. IEEFA has identified significant issues with current electricity network economic regulation, which has allowed networks to gain systemic supernormal profits (profits above the regulator's target levels) for the last decade. Between 2014 and 2023, IEEFA estimated that networks made $15 billion in supernormal profits, which delivered total profits 1.85 times allowed levels. In 2023 supernormal profits skyrocketed to an estimated $4.35 billion, more than a third of total network revenue that year. While IEEFA can only calculate approximate estimates due to the limited data published by the AER, the AER confirmed that our figures are within 15% of their own calculations. Despite IEEFA raising this issue with governments, nothing has been done yet to correct it.

(IEEFA similarly found gas networks have been gaining systemic supernormal profits. We estimated that between 2014 and 2022, gas networks made $1.8 billion in supernormal profits, resulting in total profits that were nearly double allowed levels. The largest driver of these supernormal profits was networks systematically underestimating gas demand in their revenue forecasts.)

More broadly, IEEFA has identified a need for an in-depth review of distribution network economic regulation, to ensure that there is no over-investment, that the electrification transition is managed equitably, and that distributed energy resources (DER) that can deliver network services are allowed to compete equitably with network solutions.

Improving competition in dispatchable assets like grid-scale batteries, gas and hydro generation could also help push prices down, given they frequently set the wholesale spot price. The AER identified that most dispatchable capacity in the NEM is owned by large gentailers, who can exercise market power at peak times. The NEM review in August 2025 highlighted that "Market concentration and an ability to allocate firm generation to a gentailer's retail arm through opaque internal accounting raises risks for liquidity and competition in the market." It proposed actions to reduce market concentration. This issue affects wholesale electricity prices at peak times, and also affects the ability of different technologies to compete with each other. For example, the likelihood that grid-scale batteries will outcompete gas is diminished if battery and gas generation assets are owned by the same companies.

## Gas supply

### *Australia is fast running out of low-cost gas*

The east coast gas market has historically relied on gas production from the Gippsland, Bass and Otway Basins in offshore Victoria, and the Cooper Basin in South Australia. This gas was cheap, with pricing around $3 per gigajoule (GJ). However, those basins are now in decline, with AEMO anticipating a halving in production from southern gas fields between 2024 and 2029. LNG exports from Queensland drew on these fields, accelerating the depletion of existing reserves.

Gas producers are responding by developing new gas fields. However, marginal and lifecycles costs for a wide range of gas fields in eastern Australia show that production costs for undeveloped reserves and resources are higher than current production costs. For example, the new Kipper Turrum Tuna gas field in offshore Victoria required expensive new processing infrastructure due to higher levels of impurities than legacy fields, increasing costs to an estimated $8.40/GJ.

The largest gas fields currently being considered also come with high production and transport costs. The Australian government estimates that Santos's Narrabri gas project is likely to have a production cost of $9.90/GJ, with a cost as high as $12.62/GJ delivered to Melbourne. Gas from the Beetaloo basin is estimated to have a lower production cost, but higher costs delivered to Melbourne ($12.71/GJ) given the much longer distance. In Western Australia, IEEFA estimates Woodside's proposed Browse gas project will have a production cost of $7.80/GJ, and a delivered cost to Perth of just over $9/GJ, about four times more expensive than existing production costs for gas supplied domestically.

### *The cheapest way to supply gas for Australians is to divert some LNG*

The Australian government estimates the average gas production cost from existing fields in Queensland (including LNG projects) is much lower than those new large fields: about $6.80/GJ, with a delivered cost to Melbourne of about $9.57/GJ. Origin Energy, the upstream operator of the APLNG project in Queensland, estimated a production cost in FY2023-24 of just $4.20/GJ. Similarly in Western Australia, the production costs associated with existing gas fields linked to LNG projects in the Dampier zone is estimated to be $3.0-3.5/GJ.

In the context of looming gas shortages in both eastern and Western Australia, and an impending global LNG supply glut, it would make sense to divert small volumes of uncontracted LNG feedgas to the domestic market to meet local demand and reduce prices.

Australia is one of world's largest LNG exporters, with about 80% of Australian gas production either exported as LNG or used by LNG exporters in their operations. In eastern Australia, IEEFA estimates that redirecting a small portion of LNG spot sales (beyond contracted volumes) would be enough to alleviate forecast shortages this decade.

In the next decade, the expiry of Gladstone LNG (GLNG)'s largest contract in 2031 could free up about 180PJ of gas, which would be more than enough to meet forecast shortages. There are strong arguments for not renewing or extending the contract, given that GLNG has consistently taken about 100-150GJ per year from the domestic market between 2017 and 2024 to meet its contractual requirements. It is also forecast to have a growing supply gap to meet the contracted volumes.

In Western Australia, IEEFA found that alleviating the gas shortages would require diversion of just 4% of forecast LNG exports in 2034, equivalent to about 12% of forecast uncontracted gas exports.

Another argument for diverting some LNG feedgas to the domestic market is that LNG exports were the major driver behind a tripling in gas prices in Eastern Australia, and likely a critical driver behind a doubling in gas prices in Western Australia. The Australian Competition and Consumer Commission (ACCC) has stated that "LNG producers in Queensland typically see LNG netback prices as a domestic price floor, and suppliers have sought much higher prices where possible." This is in contrast to historic pricing behaviour in eastern Australia, in which gas was typically priced on a cost-plus basis under long-term contracts.

Developments in LNG markets mean that Australian LNG will not be needed to ensure energy security in our trading partners. An unprecedented wave of new LNG investment is set to increase capacity by a staggering 360 billion cubic metres by the early 2030s, equivalent to a 60% increase. The surge in capacity will start from next year, which will see a 10% increase in global capacity, likely depressing prices in order to unlock new demand from price-sensitive markets. The IEA predicts a global supply glut will persist until 2035 under a 2.4°C aligned scenario, and permanently under a 1.5C aligned scenario, just accounting for projects already under construction.

The IEA also notes that if significant oversupply this decade is to be absorbed by the market, it would effectively require lower clearing prices (below long-run marginal costs), less electrification, and slower rollout of renewable energy and energy efficiency than forecast in its 2.4°C scenario, which would slow the global energy transition.

In addition, IEEFA has estimated that Japan onsells about a third of the LNG if buys from Australia to third countries, meaning it could reduce its imports from Australia significantly without impacting its energy security.

Both the Labor government and the opposition Coalition are considering mechanisms that would be effective at diverting some LNG feedgas to the domestic market and put downward pressure on domestic prices. Ahead of the May 2025 federal election, the Coalition proposed the introduction of a gas reservation policy in eastern Australia. The policy would have required LNG exporters to supply an additional 50-100 PJ of gas domestically and applied a 'Gas Security

Incentive' (in other words, a tax) on some gas exports to delink domestic gas and international LNG prices.

Following the election, the Labor government announced a Gas Market Review to assess the efficacy and effectiveness of current gas policy settings. The government is reportedly considering implementing an LNG export licensing framework that would require LNG exporters to supply specified volumes of gas domestically to receive export permits. This mechanism has received support from a range of stakeholders, including APLNG, the largest LNG exporter in eastern Australia.

Market concentration issues also drive prices up. The ACCC has noted that "upstream markets are uncompetitive and remain dominated by the Queensland LNG producers and their associates, who influence over 90% of east coast reserves." Lack of competition means suppliers don't have to offer competitive prices, and that buyers have limited bargaining power to negotiate prices or terms. Addressing this lack of competition is critical to driving prices down and improving contract terms in eastern Australia.

## Electricity and gas demand

### *A focus on homes could slash energy bills*

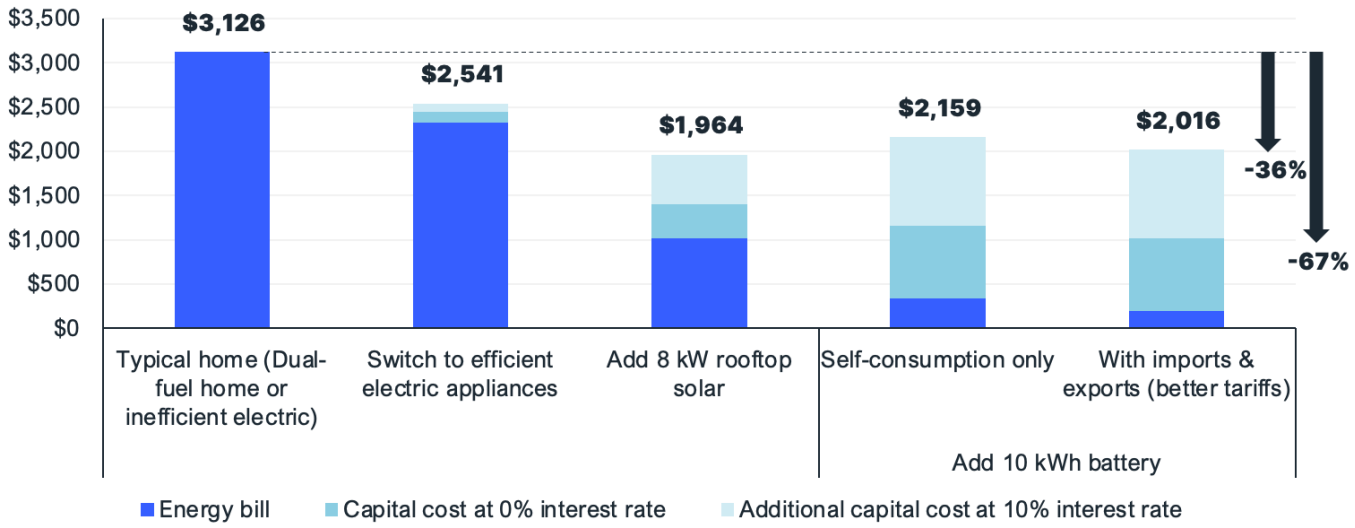
The demand side of the energy equation is often underappreciated in the energy debate, with a significant focus on the supply side. However the demand side holds arguably the largest potential to deliver energy bill reductions for households.

There is very large untapped potential to reduce net household energy bills through the shift to efficient electric appliances and the adoption of solar and battery systems. IEEFA has estimated that around 940,000 new gas appliances and 800,000 new resistive electric appliances are installed in Australia each year. However, heat pump-based equipment such as reverse cycle air conditioners now offer much higher efficiency for competitive prices.

A gas ducted heater consumes between five and nine times as much energy as an efficient electric heater, while inefficient gas and electric water heaters consume three to five times as much energy as efficient electric alternatives. We calculated that locking in inefficient appliances is locking Australian consumers into $3.4 billion in unnecessary costs each year, even after accounting for the additional cost of the efficient equipment.

We found that shifting to efficient electric appliances and adding a solar and battery system could slash household energy bills, reducing them by about 90% in most states. Figure 3 below shows that even when accounting for the full capital costs of the new equipment, net energy costs would still be reduced by about one to two thirds depending on the interest rate paid.

**Figure 3: Net energy bill impact of shifting to efficient electric appliances, adding solar and a battery for an average Australian household, $ per annum**




*Source: IEEFA (weighted average of results across major capital cities, including government rebates).*

Similar benefits exist from a shift to electric vehicles (EVs). The government's analysis of increased vehicle efficiency standards showed that the fuel and maintenance savings from accelerating the shift to electric and more efficient vehicles far outweighs the additional costs of the vehicles. The analysis showed that everyday Australians could save $108 billion in fuel costs by 2050, the largest contributor to energy costs today. The government's EV analysis excluded the potential benefits of bidirectional charging, which could be significant, especially when noting that EVs are cost-competitive with standalone household batteries on a per-kilowatt-hour (kWh) basis.

### *Untapped opportunities in industrial energy efficiency and electrification*

When it comes to businesses, there are also many untapped opportunities to reduce energy costs. Many small-scale industrial energy efficiency programs have found large opportunities to reduce energy use with paybacks lower than two years.

A striking example is compressed air systems, which represent about 10% of industrial electricity use. The Australian Alliance for Energy Productivity found that 30% to 65% of compressed air produced in manufacturing processes is lost through leaks. Across 49 sites, energy costs were more than halved via interventions that typically had payback periods of six months. It also found that alternative technologies could deliver energy savings of up to 90%, offering a variety of business productivity benefits.

A Climateworks Centre analysis of energy efficiency opportunities implemented by large industrial energy users under the federal government's now-defunct Energy Efficiency Opportunities (EEO) program found that the top 20% of performers achieved energy savings that amounted to about 14% of their energy use – the average was just 2.4%. The main factor that differentiated top performers from other companies was their regular analysis of energy data. This trend was observed regardless of the sector or the energy intensity of the company. Since the program's closure in 2014, there has been no large-scale scheme targeted at capability improvements on energy efficiency in Australian industry.

IEEFA also found that commercially available industrial heat pumps (IHP) could reduce energy use in the food and beverage sector by 80-90%, but local take-up remains very limited. In New Zealand, a government program was able to catalyse the local IHP industry by awarding less than $50 million in government grants. The program has already captured about a quarter of the total potential. IHPs could also become commercial in the alumina sector, where they can replace 5GJ of gas with 1GJ of electricity, but the technology needs government support for demonstration and derisking.

Further government policy and support for energy efficiency and electrification could deliver significant energy cost reductions for industrial businesses. Importantly, focusing on reducing gas use where cost-effective in the residential and industrial sectors would help ensure there is enough lower-cost gas left for harder-to-abate sectors that will not be able to transition as quickly.

### *Demand side action can reduce costs for all*

Improving energy efficiency can reduce the amount of investment required in electricity generation and ease the pressure on the deployment of new generation capacity. IEEFA analysis found that shifting from resistive to efficient electric appliances nationally could more than offset the additional demand from electrification of appliances. Analysis by Climateworks Centre and the Energy Efficiency Council found that energy efficiency upgrades could deliver 46 terawatt-hours in electricity savings by 2035, nearly 20% of current demand.

Importantly, it is not just the volume of energy demand that can be reduced, but also the timing of the demand that can be changed. Researchers from the University of Technology Sydney calculated that households could save up to $6.7 billion a year by 2040 if hot water systems are electrified and can be dynamically managed. However, Australia doesn't have mandatory flexibility standards for hot water systems, and almost all government incentive programs that support hot water electrification fail to include any requirements for the systems to have flexibility capabilities.

IEEFA modelling also found that pre-heating and pre-cooling homes with thermally efficient building shells could deliver some of the benefits of a battery at a fraction of the cost. The same modelling also shows that efficient electric homes in most states could completely eradicate their peak electricity demand across the year by installing solar and battery systems. In many cases they could also contribute excess generation back to the grid at peak times, provided the right settings are in place to reward this behaviour. While our modelling identified some winter peak challenges in cold states, this could be addressed by allowing batteries to import from and export to the grid, and by improving the thermal efficiency of homes.

Better management of electricity demand and DER could drive a significant increase in the utilisation of distribution networks. CSIRO previously found that DER and electrification could drive significant reductions in the unit cost of networks, more than offsetting increases in electricity demand from electrification. In total, IEEFA estimates that DER could deliver $19bn of economic benefits to 2040 through avoided network costs and avoided generation and storage costs. However, the recent boom in household batteries is exceeding previous expectations on the deployment rate and size of household batteries, meaning the potential could be much larger.

## Conclusion

Many organisations have developed scenarios for achieving net zero by 2050 in Australia and globally. In the shorter term, the core elements of the energy transition are an accelerated deployment of renewables, energy efficiency and electrification. In this report, we identified a range of opportunities to improve energy affordability in electricity and gas across supply and demand. The table below lists those opportunities and reviews their alignment with net zero.

| | Key opportunities to improve energy affordability | Net zero alignment |
|---|---|---|
| Electricity supply | Replace retiring assets with firmed renewables, the lowest-cost option | Aligned |
| | Accelerate deployment of cost-effective energy projects | Aligned |
| | Increase competition in dispatchable generation | Neutral |
| | Ensure network spending is timely, efficient and optimises existing capacity | Neutral |
| | Fix regulation to address networks' supernormal profits | Neutral |
| | Allow DER to compete with distribution network expansions | Aligned |
| Gas supply | Avoid developing large new gas fields, which may push domestic gas prices up | Aligned |
| | Divert some uncontracted LNG to the domestic market | Neutral |
| | Improve transparency and competition in the gas market | Neutral |
| Electricity and gas demand | Accelerate deployment of energy efficiency in homes and businesses | Aligned |
| | Accelerate the shift to efficient electric appliances and electric vehicles | Aligned |
| | Accelerate deployment of industrial heat pumps where cost-effective | Aligned |
| | Accelerate deployment of household solar and batteries | Aligned |
| | Incentivise consumers to maximise system benefits of DER | Aligned |

We find that all the key opportunities to improve energy affordability are either aligned with net zero or neutral to climate policy outcomes. The narrative that Australia must choose between lowering bills and cutting emissions is simply false.

Our analysis also shows there is a lot of room for improvement when it comes to energy affordability – but it is not about choosing a different electricity generation mix. It is about fixing inefficient energy markets and regulation, increasing competition, and acting on the demand side.

## About IEEFA

The Institute for Energy Economics and Financial Analysis (IEEFA) examines issues related to energy markets, trends, and policies. The Institute's mission is to accelerate the transition to a diverse, sustainable, and profitable energy economy. www.ieefa.org

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