



Australian Government
The Treasury



Australian Government
**Department of Climate Change, Energy,
the Environment and Water**

OPTIONS TO PROVIDE ENERGY PRICE RELIEF

Impact Analysis

**Department of Treasury and Department of Climate Change,
Energy, the Environment and Water**

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Glossary

ACCC: The Australian Competition and Consumer Commission.

ADGSM: The Australian Domestic Gas Security Mechanism.

AEMO: The Australian Energy Market Operator.

AER: The Australian Energy Regulator.

Competition and Consumer Act (CCA): *Competition and Consumer Act 2010.*

Consumer Price Index (CPI): CPI is a measure of the average change over time in the prices paid by households for a fixed basket of goods and services.

Default market offer (DMO): DMO is a maximum price that retailers can charge electricity customers on default contracts known as standing offer contracts in Southeast Queensland, NSW and Tasmania. The AER determines the DMO price each year.

East coast gas market: The interconnected gas market covering Queensland, South Australia, New South Wales, the Australian Capital Territory, Victoria, Tasmania and the Northern Territory. Note that the Northern Territory is physically connected to the east coast transmission network via the Northern Gas Pipeline, but that pipeline is currently not operating.

Gentailer: Vertically integrated energy market participants operating as both generator and retailer.

GFG: Gas fired generation.

GJ: Gigajoules.

Heads of Agreement (HoA): A voluntary agreement between Australia's East Coast LNG exporters and the Australian Government which gives Australian domestic gas buyers first right of refusal on uncontracted gas.

Liquefied natural gas (LNG): Natural gas that has been converted to liquid form for ease of storage or transport.

LNG exporter: LNG exporters process and prepare natural gas, using liquefaction, into LNG for transmission and sale to overseas markets. In this IA, the term is usually used in reference to one or more of the three LNG exporters in Queensland, being Australia Pacific LNG (APLNG), QGC, and Gladstone LNG (GLNG). There are also LNG exporters in the Northern Territory and in Western Australia.

MWh: Megawatt-hour.

NEM: the National Electricity Market.

PJ: Petajoules.

Spot market: The sale or purchase of gas using a spot market. In Australia's facilitated markets, these are typically for a delivery on a single gas day shortly after the transaction has been finalised.

Australia's Gas Supply Hub allows for the trade of gas over longer time frames (i.e. more than one day). Spot market transactions are distinct from transactions under gas supply contracts.

Total Market Security Obligation (TMSO): A mechanism under the ADGSM which determines which LNG producers will supply gas to the domestic market.

Voluntary Code of Conduct: The voluntary Code of Conduct for the Negotiation and Development of Gas Supply Agreements between Gas Suppliers and Gas Customers in Australia is an annexure in the Heads of Agreement and governs the behaviour and conduct of gas suppliers and customers in their negotiations of supply agreements.

Executive Summary

Rising energy prices caused by a confluence of global and domestic disruptions are intensifying cost-of-living pressures for many Australian households and businesses and are contributing to high levels of inflation and related macroeconomic pressures.

Globally, Russia's invasion of Ukraine and the resulting restructuring of global energy trade is disrupting supply in global energy markets and contributing to significant spikes in international energy prices. Domestically, weather conditions, supply chain disruptions, and planned and unplanned outages at coal power stations have increased reliance on gas-powered generation, reducing wholesale market competition and increasing exposure to international prices.

Combined, these factors have been pushing up domestic wholesale electricity and gas prices since early 2022. In the October Budget, retail electricity prices were expected to increase by an average of 20 per cent nationally in late 2022, and a further 30 per cent in 2023-24. Based on the latest available information and updated advice from the Department of Climate Change, Energy, the Environment and Water (DCCEEW) and the Australian Energy Regulator (AER), Treasury's latest estimates indicate that without intervention, national retail electricity prices in 2023-24 are expected to rise by 36 per cent. Higher electricity costs will have both a direct and indirect impact on inflation, increasing the prices of goods and services across the CPI basket. Retail gas prices were also expected to increase by an average of 20 per cent nationally in 2022-23, and a further 20 per cent in 2023-24, particularly in the National Electricity Market (NEM) and east coast gas market.

These cost pressures are yet to fully flow through to consumers as electricity and gas retailers are hedged against these impacts, providing a buffer through the recent market disruption. However, such increases are expected to pass through to higher consumer prices once wholesale contracts are renewed.

The Government is seeking to limit the expected increases in energy prices and their impacts on households, businesses and the economy. It is anticipated that while high global prices persist, a solution that provides relief to consumers and eases cost-of-living pressures is necessary. To this end, five options have been developed to target gas supply and price to limit the expected increase in energy prices.

The policy options, either individually or in combination, are designed to:

- put downward pressure on wholesale electricity and gas prices;
- put downward pressure on consumer energy bills; and
- enhance transparency and processes that support competitive pricing for electricity and gas consumers.

In addition to this, in assessing the policy options outlined in this Impact Analysis, the Government has looked to:

- minimise any unintended consequences in the national energy market;
- maintain incentives for investment;

- ensure sufficient, reliable, and affordable domestic electricity and gas supply;
- minimise impacts on international trading partners and investment;
- be timely and amendable after review; and
- minimise implementation costs and complexity for government and industry.

These core objectives and principles are aimed at targeting short-term energy price increases to provide relief to consumers, while also supporting the transition towards renewables and less carbon intensive energy streams. The objectives are applied throughout this Impact Analysis to assess the options considered by Government, and to determine the best option to address rising energy prices.

The five developed policy options are:

- A1 – Legislate a new framework for the making of energy market codes within the *Competition and Consumer Act 2010 (CCA)*, and prescribe a mandatory Code of Conduct for wholesale gas markets
- A2 – Prescribe a mandatory Code of Conduct for wholesale gas markets under the existing industry codes framework (Part IVB of the CCA)
- A3 – Work with industry to strengthen the existing voluntary Code of Conduct
- A4 – Temporary 12-month gas price cap
- A5 – Bringing forward commencement of reforms to the Australian Domestic Gas Security Mechanism (ADGSM)

The policy options were developed through consultation within government and in targeted industry discussions.

From this analysis, a combination of three responses presents the greatest benefit to Australia with regard to the objectives and principles and should progress to implementation. These options are:

- A1 – Legislate a new framework for the making of energy market codes within the CCA, and prescribe a mandatory Code of Conduct for wholesale gas markets
- A4 – Temporary 12-month gas price cap
- A5 – Bringing forward commencement of reforms to the ADGSM

It is proposed these policies are progressed as a suite because they work in concert to mitigate the risks present in individual policies implemented in isolation. They provide price certainty in the short term, will enable positive behavioural standards in negotiations to be enforced, ensure supply to the domestic market, and place obligations on both sellers and buyers to act in good faith.

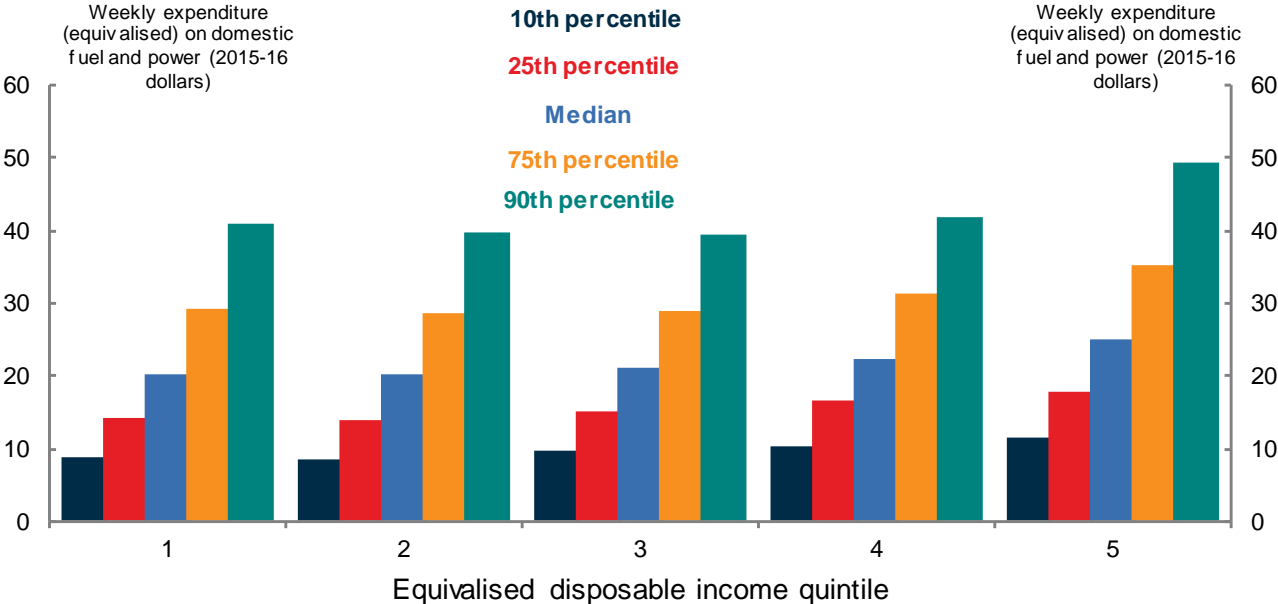
While these policies work to address immediate energy market pressures, the Government is already implementing a range of non-regulatory measures to support Australia’s long-term transition to a renewable-based grid, including those committed to by the Government in the 2022-23 October Budget. Broadly, these measures seek to improve market dynamics and put downward pressure on prices through the energy transition, including to address the underinvestment resulting from the past decade of policy uncertainty.

What is the problem you are trying to solve?

Rising energy prices caused by disruptions in global energy markets are putting pressure on Australian households

Rising energy prices are intensifying cost-of-living pressures for many Australian households and businesses and eroding living standards. Sharp rises in the cost of essentials, such as energy bills, creates pressure for all households, with the median household in each income quintile spending roughly the same amount on energy (Chart 1). These pressures are particularly acute for lower income households where these expenses make up a larger share of their budgets (Chart 2). To demonstrate the scale of the current problem, the AER has reported that the number of households in energy debt has risen, with 170,547 energy customers taking part in hardship programs at the end of 2021-22. This was 23,286 more customers than in 2018-19.¹

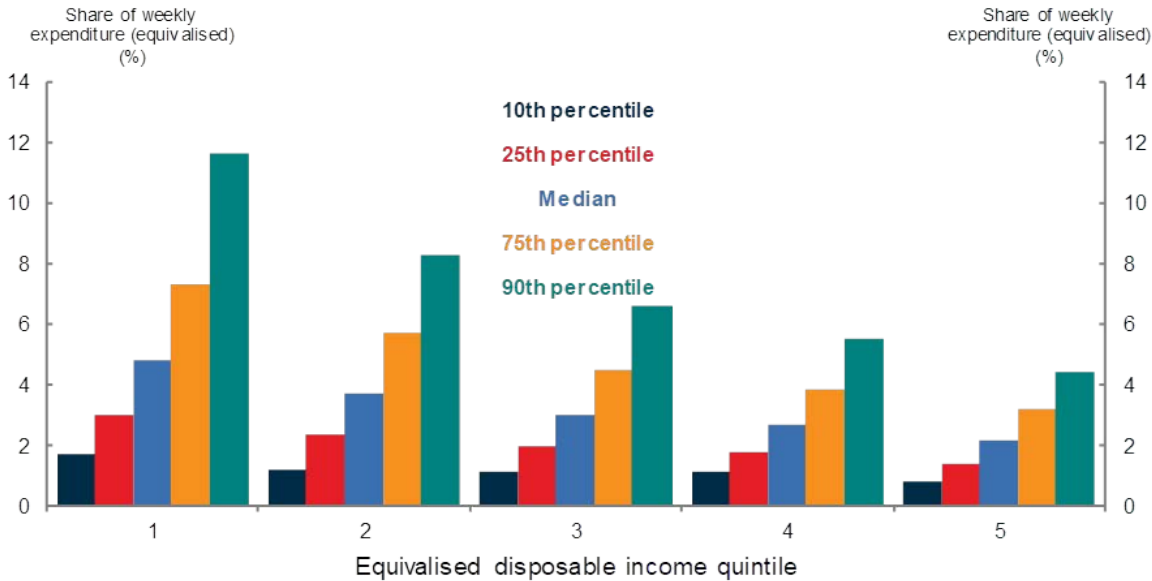
Chart 1: Weekly expenditure on domestic fuel and power by income quintile



Source: Treasury, ABS Household Expenditure Survey 2015-16

¹ AER, *Towards energy equity: A strategy for an inclusive energy market*, October 2022.

Chart 2: Share of weekly expenditure on domestic fuel and power by income quintile



Source: Treasury, ABS Household Expenditure Survey 2015-16

The rise in Australian electricity prices has been largely driven by high international gas prices, reflecting international market conditions. Disruptions in the domestic wholesale market have further exacerbated these issues.

Russia’s war in Ukraine has disrupted global energy supply, driving significant additional rises in international energy prices, which were already elevated due to pandemic-related supply chain disruptions and the increase in consumer demand from economies recovering from COVID-19 lockdowns. Restrictions to gas supplies have had ripple effects, flowing through to broadening price pressures in Europe and higher gas prices in other countries dependent on gas imports. Global gas prices peaked at six times their March 2021 level in August 2022 and, though they have fallen since this peak, prices remain significantly above historic levels (see Chart 3). Prices are expected to stay substantially above historical averages over the next few years.²

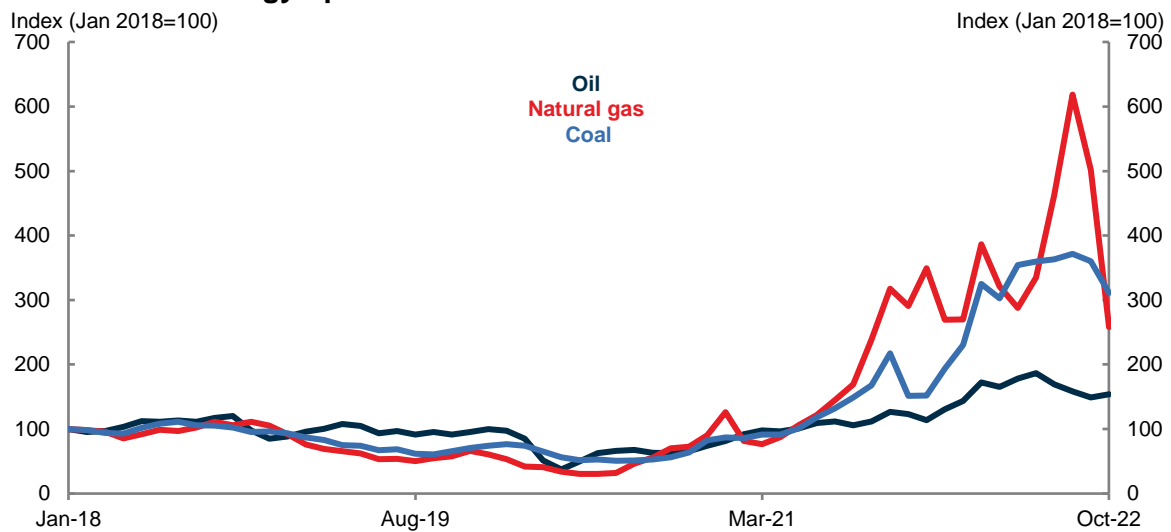
This has contributed to higher domestic fuel costs and flowed through to higher energy prices, as Australian gas prices are influenced by international market conditions. The spike in global prices coincided with large domestic wholesale market disruptions that increased reliance on gas-fired generation, including the early onset of winter in 2022 as well as planned and unplanned maintenance at coal power stations. While this is impacting on industrial customers’ viability, households are ultimately paying more for energy and other goods where production is reliant on gas.

Foreign governments are facing the same international crisis, and many are responding with significant interventions. The biggest response has been in Europe, where the move away from Russian gas has caused the greatest disruption in supply and hence price. European measures and policy options to address both supply and price have included: price caps and rebates for generators, households and SMEs, gas and electricity reduction targets to mitigate supply risks and power

² World Bank Commodity Market Outlook, October 2022.

outages across the European energy network; gas storage mandates of 80 to 90 per cent to ensure supply, and revenue caps and taxes on fossil fuel and energy companies to pay for rebates.

Chart 3: Global Energy Spot Prices



Source: IMF, Treasury

Impacts are being felt across the economy

In Australia's east coast market, high gas prices are expected to continue to have an impact on the prices of downstream products and electricity, affecting gas-fired power generators, spot market gas retailers and ultimately, end-users through increased retail prices. High energy bills will have a more adverse impact on lower income households, where more of the household's budget is used to cover necessities.

As a core unavoidable input, energy cost increases may make affected businesses unprofitable. Multiple businesses and industry groups across Australia have already reported that increasing energy costs are causing significant difficulty. In particular, manufacturing businesses say the increases are forcing them to divert money away from reinvestment and innovation and increasing the risk Australia may lose local manufacturing capability due to a temporary international price shock. In the September quarter 2022, the cost of gas and electricity for manufacturing businesses rose by 15 per cent and 14 per cent respectively.³ However, retailer and industrial user hedging strategies are currently providing businesses with some protection from rising wholesale prices.

While forecasts of high prices are at the national level, the actual quantum of price rises is likely to vary between states and territories. Western Australia (WA) has not faced the price increases or the volatility of the east coast, with its state-based domestic gas reservation policy ensuring gas supplies into the WA domestic market, avoiding the supply tightness experienced in other jurisdictions. Average monthly WA spot gas prices have ranged from \$5.50 to \$6.25/GJ over 2022, whereas the average east coast gas price peaked in July 2022 at over \$40/GJ, and east coast markets trading around or well above \$16/GJ through November 2022.

³ ABS Producer Price Index, September 2022

High fuel prices are leading to increases in electricity prices

High input fuel prices for generators are expected to be a key driver of current and forecast high wholesale electricity prices. Unplanned outages of Australia's ageing coal generation assets or disruptions to fuel supply are likely to see increased reliance on spot markets for power generation and renewed periods of upward pressure on prices.

Wholesale electricity spot prices in the NEM are set by the marginal unit – the highest bid generator that is dispatched to supply electricity. Gas-powered generation accounts for a relatively small share of electricity output (around 5 per cent), but it can be important in driving competition and determining the clearing price in peak demand periods in the NEM.

Wholesale electricity prices in the NEM experienced sharp price increases in 2022, starting from \$103/MWh in January to peaking at \$392/MWh in July 2022. While these prices have stabilised since July, they are still 75 per cent higher than the average in 2021 and are expected to stay elevated over the next few years. Futures contracts for wholesale electricity in 2023-24 and 2024-25 are currently trading at around \$165/MWh and \$140/MWh⁴ respectively, well above the average price at the end of 2021 of around \$62/MWh.⁵

Gas

Domestic wholesale gas prices in the east coast market remain more than double their average prior to Russia's invasion of Ukraine.

Both new gas price contract offers and spot prices across the east coast spiked in 2022. The duration and height of the price spike from May to August 2022 was unprecedented for Australia's east coast gas market. At the Wallumbilla Gas Supply Hub in Queensland, prices reached a peak of \$47.50/GJ in July and have remained elevated for most of September and into November. Prices exceeded \$50/GJ in Victoria.

While spot prices have recently fallen across the east coast market, they remain volatile and historically high with markets ranging between \$10 and \$23/GJ for November 2022. New contract offer information shows volume weighted offers from gas producers and retailers made between March 2022 and August 2022 for supply in 2023 have doubled from the September 2021 to February 2022 period.⁶ Weighted average gas producer offers increased from \$10.51/GJ to \$19.66/GJ and retailer offers increased from \$9.84/GJ to \$20.16/GJ.

In Australia's east coast gas market, the majority of trade is struck under confidential bilateral contracts, with around 10 to 20 per cent of gas traded in organised spot markets.⁷ Confidential bilateral contracts range in length from months to multiple years, although contracts longer than three years are less common. Longer term contracts have provided a measure of protection for gas

⁴ Baseload 2024 and 2025 financial year futures, simple average of the four ASX-traded regions (NSW, Qld, Vic, SA), as of 22 November 2022

⁵ Baseload 2024 financial year futures, simple average of the four ASX-traded regions (NSW, Qld, Vic, SA), as of 30 December 2021.

⁶ ACCC, *January 2023 interim report – Preliminary gas pricing*, 14 November 2022. Available from www.accc.gov.au.

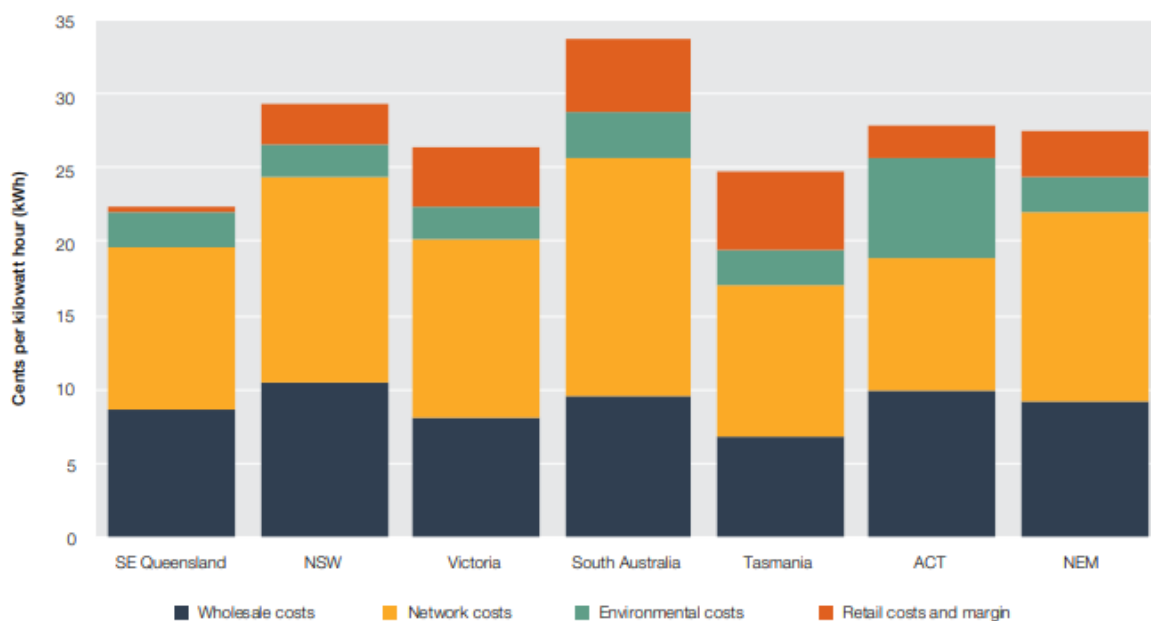
⁷ Australian Energy Regulator, *State of the energy market 2022*, 29 September 2022.

users from the high prices of the last six months, however high market prices will impact the price of new contracts as they are negotiated.

High wholesale electricity costs are flowing through to retail prices

Rising wholesale electricity costs will flow through to end-users of electricity. The factors that make up consumers’ final electricity bills are illustrated in Chart 4 below, with network costs and wholesale costs being key components of the final price end-users of electricity face. As wholesale electricity costs have historically made up between 30 and 40 per cent of retail bills, the expected increase in wholesale electricity and gas prices will have an impact on energy bills for end consumers.

Chart 4: Costs contributing to final retail electricity bills by State



Note: Cost components for the average residential customer in 2021–22, excluding GST. Calculated using trends in supply chain components for each jurisdiction and national trends.

Source: AEMC, *Residential electricity price trends 2021*, 25 November 2021 (using data from Energy Made Easy and Victorian Energy Compare on 17 September 2021).

The impact of wholesale prices on retail electricity prices has flowed through to some extent in the AER’s 2022-23 Default Market Offer (DMO) determination compared to the previous financial year. The 2022-23 DMO determination saw residential customers with standing offers face nominal increases of around 7 to 18 per cent on their electricity bills, and small businesses face increases of up to around 20 per cent. While standing offer customers represent approximately 10 per cent of residential customers and 18 per cent of small business customers in the DMO regions (New South Wales, South-East Queensland and South Australia), and noting that wholesale costs typically represent 30 to 40 per cent of bills, these increases provide insight into the flow-on impact of wholesale electricity prices onto retail electricity prices for consumers.

Retail electricity prices are expected to have increased by an average of 20 per cent nationally in the second half of 2022, largely reflecting the 2022-23 DMO determination. Looking forward, the October 2022 Budget forecast that retail electricity prices would rise by a further 30 per cent in 2023–24. Treasury also expected increases in retail gas prices of 20 per cent in 2022-23 and 20 per cent in 2023-24. Based on the latest available information and updated advice from government

agencies and regulators, Treasury now forecasts, that without intervention, national retail electricity prices in 2023-24 would rise by 36 per cent.

These price increases are also affecting business profitability and may threaten the long-term sustainability of some businesses.

Current government frameworks could be strengthened

Existing policy levers available to the Commonwealth are targeted at ensuring supply of gas while allowing markets to determine commodity pricing.

Under the Heads of Agreement (HoA), which was renewed in September 2022, LNG exporters have committed to offer uncontracted gas to the domestic market before it is offered to the international market, with reasonable notice, for reasonable supply periods and on competitive market terms. A gas producer-led voluntary Code of Conduct is annexed to the HoA, with the intent of placing minimum standards on LNG exporters and other signatories when negotiating with customers to enter into gas supply contracts. This includes an obligation to act in good faith and comply with obligations to ensure transparency around pricing.

The ACCC has recommended ways to strengthen the key obligations within the voluntary Code of Conduct, including by making it mandatory. A mandatory Code of Conduct would mean it applies to all sellers, regardless of whether they opted into the existing voluntary Code of Conduct and would include giving the ACCC powers to monitor compliance with the Code of Conduct and take enforcement action if non-compliance is identified. The ACCC has also recommended the mandatory Code of Conduct include a binding arbitration process to resolve disputes between gas sellers and buyers at the wholesale level. Further, in its most recent report⁸, which was published prior to the new HoA being signed, the ACCC indicated concern that one of the east coast LNG exporters was making offers at prices far above what it receives for uncontracted gas in overseas markets.

If a gas supply shortfall is forecast for Australia, the Commonwealth can, through the ADGSM, limit LNG exports to ensure gas is available to meet Australia's domestic demand. The ADGSM is a measure of last resort that allows the Commonwealth to impose export controls on LNG projects where the relevant Minister considers that doing so would prevent a domestic gas shortfall. The regulatory impact of the ADGSM was considered in the regulatory impact analysis released in June 2017 – which can be accessed on the Office of Impact Analysis website⁹.

While the ADGSM can limit exports during a gas shortfall year, it cannot be activated based on price. Further, the current version of the ADGSM requires the Minister for Resources to initiate the ADGSM process between 1 July to 1 October the year before a projected shortfall, with export controls only coming into effect on 1 January the next calendar year. To address shortcomings in the ADGSM, the Government recently announced improvements to the functioning of the ADGSM, including:

- moving from the current 'calendar year' model of activation to a rolling 3-month (seasonal) cycle to improve speed and flexibility.
- moving from the current 'net deficit' model of allocating volume shortfalls to exporters to:

⁸ ACCC, Gas Inquiry Interim Report, July 2022

⁹ Office of Best Practice Regulation, Australian Domestic Gas Security Mechanism, November 2017.

- splitting the Total Market Security Obligation (TMSO) equally across all exporters in the market in shortfall.
- making export permissions tradable between exporters.

These reforms are currently scheduled to commence on 1 July 2023 and were considered through OBPR22-02706 released in October 2022 – which can be accessed at the Office of Impact Analysis website¹⁰. This Impact Analysis considers the merits of bringing forward the commencement of these reforms to 1 April 2023.

A package of gas market reforms being progressed by Energy Ministers will also help place downward pressure on domestic gas prices, including by enabling AEMO to identify gas supply risks, seek market responses and avoid critical supply shortages; ensuring domestic gas markets function more efficiently and transparently; and ensuring smaller producers can bring gas to the market, and key storage facilities are fully utilised.

Further to the regulatory levers outlined above, the Government is already implementing a range of non-regulatory measures that seek to ensure long-term energy supply for Australians while supporting the transition to a renewable-based grid. These include:

- \$20 billion in low-cost finance through the Rewiring the Nation policy for the urgent upgrade and expansion of Australia’s electricity grid at lowest cost – to unlock new renewables, increase the security of the grid and drive down power prices.
- Providing \$157.9 million over 6 years from 2022–23 to support the implementation of the National Energy Transformation Partnership (NETP) agreed in August by Energy Ministers from each State and Territory, creating policy certainty for the first time and driving much needed investment in transmission and renewable energy projects.
 - This includes delivering critical market reforms, supporting investments in the grid such as large-scale storage, transmission and firming capacity and co-design of a First Nations Clean Energy Strategy and the development of a National Energy Performance Strategy.
- \$224.3 million for the Community Batteries for Household Solar grants program, to deploy 400 community-scale batteries for up to 100,000 Australian households.
- \$102.2 million for Community Solar Banks for up to 25,000 Australians living in apartments, rentals and low-income households across Australia.
- \$63.9 million to invest in dispatchable storage technologies, such as large-scale battery projects.
- \$62.6 million for an energy efficiency grants program for small and medium-sized enterprises to reduce energy use and lower energy bills.
- \$83.8 million to develop and deploy First Nations Community Microgrid projects to ensure remote communities benefit from improved security and affordability of energy supply.

¹⁰The Office of Impact Analysis, ADGSM – Refining the Australian Domestic Gas Security Mechanism, October 2022

These measures all seek to fulfill the Government’s long-term priorities and commitments on energy, including the transition to a renewable based grid and commitments to improve affordability and reduce greenhouse gas emissions by 43 per cent below 2005 levels by 2030 and reach net zero emissions by 2050. While they will contribute to reducing the price of energy in the long-term, their implementation time means they won’t address the immediate problem that is being resolved.

Key stakeholder groups

Australia’s energy markets involve a number of participants. The following participants and other stakeholders are considered in this Impact Analysis in determining the impacts of options to address short-term energy prices.

Table 1: Relevant stakeholder groups and their impact on energy price relief options

Stakeholder group	Role in the problem
Domestic gas producers	<p>Domestic gas producers are companies that develop, operate or have equity in gas projects throughout Australia. They can produce gas from geological reserves, either using conventional extraction methods or unconventional methods (such as coal seam gas). Domestic gas producers can sell to domestic buyers (e.g. through domestic gas supply agreements or the short-term market), or can sell gas to LNG exporters for sale into international markets. This includes gas production by projects owned and operated by joint venture partners in LNG exporters.</p> <p>Any impact to gas producers (particularly in relation to revenue) will likely have a flow-on impact to the shareholders of these companies.</p>
LNG exporters	<p>LNG exporters develop, produce and process natural gas prior to liquefying it and selling LNG Free on Board (FOB) or on a delivered basis to international buyers. There are 10 LNG export projects across WA, Queensland and the Northern Territory. In the east coast gas market, the most relevant are the three LNG exporters in Queensland, being Australia Pacific LNG (APLNG), Queensland Curtis LNG (QCLNG), and Gladstone LNG (GLNG).</p>
Electricity generators	<p>Electricity generators are companies which use inputs (e.g. fuel, renewables) to generate electricity and then offer to supply the wholesale market with a certain volume of electricity for a bid price. The highest bid price which is dispatched sets the market price. Many generators are vertically integrated and act as retailers as well, these are known as ‘gentailers’.</p> <p>Electricity generators include both public and private sector participants.</p>
Retail energy companies	<p>Energy retailers sell electricity and gas services to residential and business customers. The retail sector is the final link in the electricity and gas supply chains, providing energy services and final retail energy bills to end-user customers. The retail market is concentrated in a small number of businesses with large customer bases, but smaller retailers provide competitive tension through innovation and price competition.</p>
Domestic energy consumers (households, small business and industrial users)	<p>Realised and forecast increases in retail electricity and gas bills are contributing to cost-of-living pressures for many Australian households and are risking the viability of exposed businesses.</p> <p>In the east coast gas market, just under half of gas produced for domestic use is consumed by industrial customers, either as a fuel for industrial heat or as a</p>

Stakeholder group	Role in the problem
	chemical feedstock in industries such as chemicals, plastics and fertiliser manufacturing.
International trading partners and investors	Australia is a trusted and reliable energy exporter to our major trading partners across the world and in our region, with Australia's exports of iron ore, coal and natural gas making up our top three exports overall in 2021-22. Investors from a range of partner countries have made substantial investments in Australia's resources sector.

Further information on the east coast electricity market is provided at Appendix A.

Why is Government action needed?

Global energy market disruptions are leading to large price increases for households and businesses

The pressures outlined above have resulted in significant volatility in the east coast gas market. While high international prices persist, domestic prices are expected to be unacceptably high in the absence of intervention.

High retail energy prices are forecast to contribute to high inflation across the economy. Rising prices are reducing the real incomes of many Australian households, particularly lower income working households, and affects the viability and profitability of many businesses. These outcomes are unsustainable and will likely lead to an inefficient allocation of resources in the longer term.

The forecast status quo increases in retail energy prices will continue to contribute to inflationary pressures. Continued inflationary pressures will erode the living standards of Australians. Around 8 million Australian homes built before 2005 are estimated to have an average energy efficiency rating of under two NatHERS (Nationwide House Energy Rating Scheme) stars out of 10. Energy-inefficient housing can be stifling during summer and freezing in winter, increasing energy consumption and energy bills. Unaffordable energy prices will particularly impact low-income Australians who are high energy users with limited ability to reduce their demand, including those residing in energy-inefficient housing. Further energy price pressures are likely to exacerbate these existing issues.

The rising cost of electricity is also increasing the cost to manufacture goods and operate businesses, which is flowing to prices. Timely and targeted intervention will be able to limit these price rises and its effect on consumers.

Finally, wholesale electricity contracts for the 2023-24 financial year are currently being negotiated, with electricity retailers looking to lock in the wholesale cost of electricity they expect to purchase for their customers. Many retail contracts have already locked in retail prices for 2022-23, however, intervention now will start to limit price increases in the 2023-24 financial year. As such, there is an urgent need for swift Government action to address current and forecast high future energy prices.

Government capacity to intervene

There are several ways the Government can intervene to moderate energy prices for consumers but depending on the point of intervention these can have differing impacts along the supply chain. The Government could seek to reduce the price of wholesale electricity – either through directly targeting wholesale electricity prices or targeting the prices of inputs to electricity generation. The Government could also seek to reduce the price of wholesale gas for consumers who use gas directly as a source of energy.

Limitations to the Commonwealth's legal powers and the fragmented structure of the coal market (with different grades of coal produced for different purposes and markets), mean that intervention

on wholesale coal prices at the state level will be more effective and able to be targeted to where it is needed.

Another pathway to put downward pressure on domestic wholesale electricity prices is through measures which reduce the price of domestic wholesale gas. While gas-powered generation accounts for an apparently small share of electricity output (around 5 per cent), it is an important fuel in driving competition and setting prices in the NEM. Between Q1 and Q2 of 2022, more costly marginal fuels such as gas and hydro (which often shadows gas) set the price of electricity in the NEM more regularly than in previous periods, and the frequency of coal-fired generation setting prices declined from 48 per cent of the time to 27 per cent of the time.

There is scope for the Commonwealth to enforce price caps on uncontracted gas markets through legislation. Further, the Commonwealth already has a number of regulatory and non-regulatory levers to encourage supply to domestic gas markets – for example, the HoA and the ADGSM – which are already explored in the *Current Government frameworks could be strengthened* section. There is scope to strengthen these Commonwealth levers to ensure domestic supply, together with the implementation of a Commonwealth price cap on uncontracted domestic wholesale gas. This would be expected to flow through to minimise wholesale electricity prices as the price set by gas-fired generators is reduced, as well as reducing prices faced by industrial consumers and gas retailers (which, in turn, supply gas to small businesses and households that use gas as a direct source of energy).

Finally, governments could directly alleviate the final retail energy price faced by consumers. The AER and the ACCC could utilise their regulatory powers to monitor the impact of measures which put downward pressure on future prices and monitor the behaviour of the market participants. The ACCC can enforce provisions in Part XICA of the CCA that require electricity retailers to reasonably adjust their prices to reflect sustained and substantial cost savings.

States and territories also maintain existing schemes which deliver energy bill rebates to recipients of various concessions. Unlike the states, the Commonwealth does not have existing administrative arrangements in place with energy retailers or have a clear constitutional power to unilaterally deliver a universal concession scheme to households and businesses for the purpose of providing retail energy price relief. Thus, states and territories are best placed to provide direct retail energy bill support to consumers.

The capacity for the Commonwealth to reduce underlying drivers of consumer energy prices largely resides in the targeting of domestic wholesale gas markets. For this reason, Government action considered in this Impact Analysis largely focuses on these markets.

Alternatives to Government action

There are a handful of existing mechanisms which will assist in maintaining the supply adequacy of gas in the domestic market and support consumers facing energy cost pressures.

For example, the Government could rely on existing schemes operated by the states designed to provide relief to households. The designs of these schemes vary across states, but most target vulnerable consumers with rebates directly to their bills. There is a concern, however, the level of these rebates will not address the needs of consumers and businesses in the face of forecast energy prices.

The Government could also rely on the HoA with proponents of Queensland-based LNG export projects to ensure sufficient gas is supplied to the domestic market – however, this mechanism alone would not directly address rising prices. Through negotiations for a new HoA (which was announced in September 2022), and in response to the ACCC’s forecasted shortfall of 56 PJ in 2023, the Government secured agreement from LNG exporters to supply 157 PJ of gas for the east coast domestic market. Under this agreement, LNG exporters on the east coast have committed to first offer uncontracted gas domestically and to comply with the annexed voluntary Code of Conduct.

It is unclear whether it is possible to strengthen this commitment to ensure that offers are made and structured in ways that better support the needs of domestic customers, and thus improve the operation of domestic markets.

Objectives of Government action

At the 28 October 2022 Energy Ministers Meeting, Energy Ministers committed to consider all options to take strong action as a matter of urgency to bring down power prices for Australian households and businesses and that deeper action is needed to drive further stability and address price pressures. Ministers also concurrently recognised that a transition to renewable energy not only reduces emissions but also increases our resilience and protects consumers from such global price shocks.

To this end, the following objectives for any Australian Government action to address short-term energy prices were developed following consultation across Australian Government Departments. These objectives and principles will be used to assess the options considered in this Impact Analysis and will be used to reveal a recommended option following analysis. Objectives of government action would be to:

- Put downward pressure on wholesale electricity and gas prices.
 - This can be measured against wholesale electricity prices in the NEM and east coast gas prices. Additionally, the ACCC’s monitoring of market performance in its Gas Inquiry will provide information on gas prices being paid under contract.
- Put downward pressure on consumer energy bills.
 - This could be measured against residential and small business energy retail bills in the NEM and east coast gas markets. Impact would depend on the regulation of retail electricity markets in jurisdictions, as well as their exposure to the current price shock.
 - However, wholesale costs only make up around a third of an average consumers’ retail electricity bill, which may create a challenge in isolating the impact of government action against other factors in the retail cost stack influencing price.
- Enhance transparency and processes that support competitive pricing for electricity and gas consumers.
 - This would result in a positive shift in behaviour by suppliers and producers in their negotiations of electricity and fuel contracts, monitored where possible by the ACCC.
 - This may be measured by ongoing monitoring and reporting by the ACCC, including through the ACCC’s ongoing inquiries into gas and electricity markets.

In addition to the objectives, the following principles were identified as outcomes that must be considered, balanced and met by any relevant reform options:

- Minimise any unintended consequences in the national energy market.
 - Any market interventions can have unintended consequences. Energy price relief measures have been considered with the intention of ensuring reliable supply and minimising the risk of distorting the efficient operation of the national energy market, including through close monitoring of market dynamics and participant behaviour.
- Maintain incentives for investment.
 - Short-term measures to provide price relief are intended to be delivered in the context of the Government's broader commitment to Australia's clean energy transition.
 - Option implementation is intended to ensure the longer-term supply of domestic energy is reliable and reasonably priced, without undermining Australia's transition to net zero, or driving away additional investment in renewables.
- Ensure sufficient domestic electricity and gas supply and minimise risks to supply.
 - Continued access to gas supply remains critical to meet electricity demand during peak demand periods, and for commercial and industrial users reliant on gas as a critical input to production.
- Minimise impacts on international trading partners and international investment.
 - Australia is committed to remaining a reliable supplier and trading partner and any action to put downward pressure on prices should be coupled with clear messaging to key trading partners that Australia does not intend to reduce international gas supply.
 - The policy is designed to allow producers to continue to meet their existing contractual obligations including with international partners by applying only to uncontracted gas and clear forward guidance.
 - Actions to further minimise this risk may involve early engagement to provide reassurance of supply, which could also reduce the impact of Australia being seen as less attractive a destination for foreign investment.
- Minimise implementation costs and complexity for government and industry.
 - Short-term reforms need to be implemented quickly to provide timely relief to businesses and households. Implementation may therefore require careful targeted consultation with stakeholders, to ensure that measures are delivered efficiently and effectively.

Options considered target both current high prices and forecast future prices rises in the wholesale and retail energy market stemming from the impacts of Russia's war in Ukraine, to provide immediate relief to industry and consumers. Suitable options will be able to be implemented swiftly and likely be short-term, but adaptable to future outcomes.

Consideration of risks

Potential risks have been considered carefully in assessing intervention options open to Government. Energy markets are complex, and options to address rising energy prices have been developed with consideration of impacts to all stakeholders.

The government has placed an emphasis on the importance of maintaining Australia's attractiveness as a destination for investment in gas production. As such, the policies being considered ensure intervention takes into account a reasonable return on capital for investors. A key objective is to maintain Australia's reputation as a desirable destination for foreign investment and Australia's positive relationships with its trading partners while complying with its obligations. The Government recognises that this could be damaged if there were changes to existing contracts or prolonged policy uncertainty and has developed the proposals to ensure that this is not the case.

Price regulation also carries the potential for a range of risks to the wholesale gas market, as well as downstream and related markets which rely on gas. As gas plays an important role in the energy transition, ensuring that the price is at a level that supports this transition (too high and the transition is more costly and reliant on more carbon intensive fuel; too low and the transition to renewables is slower). The significant increase in gas prices over 2022 has created an additional incentive to accelerate the transition to lower emission sources of generation, such as pumped hydro and battery storage, which provide similar 'peaking' services. The government has worked to ensure that normalising domestic gas prices is coupled with measures to support the energy transition would offset this impact.

Another risk with efforts to put downward pressure on prices in a complex system – either at the fuel input level or at the wholesale energy market level – is that those price reductions may not flow through to price reductions or adequate consumer relief for final end-users. These risks are addressed through the ACCC's price monitoring powers under the CCA and the AER's powers under the national energy framework.

Influencing the price of any fuel input may affect their price relativities and competitiveness against other fuels, which could have flow on impacts to the operation and efficiency of related markets such as wholesale electricity markets.

These risks have been considered in the following assessment of policy options.

What policy options are you considering?

As explored in the *Capacity for Government intervention* section, Commonwealth levers to address current and anticipated energy prices are largely focused on the wholesale gas market. Thus, the Government has explored policy options to temporarily address current and anticipated electricity prices target the gas market. Those being progressed are:

Regulatory reforms that seek to reduce the price of gas:

- A0 – Maintain the status quo
- A1 – Legislate a new framework for the making of gas market codes within the CCA, and prescribe a mandatory Code of Conduct for wholesale gas markets
- A2 – Prescribe a mandatory Code of Conduct for wholesale gas markets under the existing industry codes framework (Part IVB of the CCA)
- A3 – Work with industry to strengthen the existing voluntary Code of Conduct
- A4 – Temporary 12-month gas price cap
- A5 – Bringing forward commencement of reforms to the Australian Domestic Gas Security Mechanism (ADGSM)

Non-regulatory measures that seek to reduce the price of gas:

Further to the regulatory reforms considered in this Impact Analysis, the Government is already implementing a range of non-regulatory measures that seek to ensure long-term energy supply for Australians while supporting the transition to a renewable-based grid. These are highlighted in the *Current Government frameworks could be strengthened* section.

As noted above, these measures all seek to fulfill the Government's long-term priorities and commitments on energy, including the transition to a renewable based grid and commitments to reduce greenhouse gas emissions by 43 per cent below 2005 levels by 2030 and reach net zero emissions by 2050. While they will contribute to reducing the price of energy for consumers in the long-term, these measures have long implementation times due to the nature, for example, of building transmission infrastructure and bringing online new renewable generation and storage. As such, the impacts of these non-regulatory measures will take some time to be realised.

In addition to these current measures, further non-regulatory measures could be implemented – such as policies that result in more electricity generation and storage capacity. While such measures may assist in achieving the long-term transition to renewables and in ensuring adequate supply in the long run, they are unlikely to address the current and forecast elevated energy prices over the next few years. Measures to reduce demand for energy may also help alleviate pressures in the event of inadequate supply. This could be considered for example through providing support to consumers to invest in more energy efficient appliances and housing, or by creating energy demand

targets. Given the scale of the international price shock however, these measures are unlikely to provide immediate or substantial price relief.

Status quo (Option A0)

The status quo option would involve no regulatory intervention by the Government in the energy market. Absent any price regulation or other intervention, sustained high energy prices, including further price increases, are likely to continue impacting Australian businesses and households.

Under the status quo, behavioural standards of dealings between gas producers and customers in the east coast will continue to be governed under the existing voluntary Code of Conduct, which only applies to gas suppliers who choose to opt in. Accepting the status quo option may see limited improvement in the systemic, behavioural issues present in the wholesale gas market.

Regulatory reforms that seek to reduce the price of gas

Mandatory Code of Conduct for the wholesale gas market (Options A1, A2)

Options A1 and A2 involve developing a mandatory Code of Conduct that would set minimum standards of behaviour for dealings between east coast gas producers and wholesale customers in the negotiation of gas supply contracts.

The mandatory Code of Conduct would be a strengthened version of the existing voluntary Code of Conduct annexed to the HoA between the Government and east coast LNG exporters, and the advice provided by the ACCC to the Government. Broadly, the mandatory Code of Conduct would build upon and strengthen the voluntary Code of Conduct by strengthening transparency, reporting, pricing and the negotiating environment. The provisions of the mandatory Code of Conduct will depend upon the implementation mechanism (A1 or A2). For example, under Option A1, the maximum available penalties for non-compliance would be significantly higher than under Option A2.

The ACCC would administer and enforce compliance with the mandatory Code of Conduct. The ACCC would also monitor and report on the impact of the mandatory Code of Conduct on electricity and gas markets, through its existing price inquiries into electricity and gas markets.

A review of the mandatory Code of Conduct would be conducted after an appropriate period (such as a year), once its impacts have been observed, to consider any necessary refinements or improvements to the Code of Conduct, including its coverage.

Options to implement a mandatory Code of Conduct are:

- A1 – Legislate a new framework for the making of gas market codes within the CCA, and prescribe a mandatory Code of Conduct for wholesale gas markets.
- A2 – Prescribe a mandatory Code of Conduct for wholesale gas markets under the existing industry codes framework (Part IVB of the CCA).

A further option for a Code of Conduct, over and above the existing voluntary Code of Conduct (Option A0) but short of a mandatory Code of Conduct is:

- A3 – Work with industry to strengthen the existing voluntary Code of Conduct

Gas price cap (Option A4)

This option would involve implementing a temporary, emergency price cap reflecting costs of gas production, including a reasonable return on capital, applying to wholesale sales of gas by producers in the domestic wholesale market, excluding WA, spot market transactions and undeveloped fields. While the price cap would be temporary, different design specifications were considered for the length of time this cap should be in place.

The price cap would apply where the following conditions are met:

- The seller is a gas producer (including sales made on behalf of gas producers by a related entity or other affiliate, such as an agent);
- The gas is sold via wholesale contract (either directly negotiated between the parties or reached following a trade through the Gas Supply Hub);
- The contract is agreed, and the gas is to be supplied, while the price cap is in effect (that is, the price cap would not impact on existing contracts); and
- The gas to be supplied is immediately available supply sourced from developed fields.

The price cap would not apply to gas sold on retail markets (for example, gas sold by retailers to residential or small business customers) or to non-producers, such as retailers, where they sell gas via bilateral contract at the wholesale level.

The cap would be set at a level which reflects the costs of gas production, including a reasonable return on capital, for gas available for immediate supply from developed fields, while excluding the extreme inflation in energy prices which has occurred in response to the Ukraine war and resulting global energy shock.

The ACCC has advised it considers a price of \$12/GJ reflects the costs of gas production, including a reasonable return on capital for gas sourced from developed fields capable of supply during the period in which the emergency price rule is of application fields. While the cost of production from undeveloped fields could differ from this level, these fields are not included within the scope of the price cap.

In arriving at this price, the ACCC considered the prices that were offered on the east coast in 2021, for supply in 2023, prior to international prices increasing in late 2021 in response to overseas factors. Over 2021, there were 289 domestic offers made by producers and retailers, with 96 per cent of offers made below \$12/GJ and an average price of \$9.20/GJ. The level of the price cap will be confirmed following a brief, targeted consultation which would enable the Government to gather more information on costs and prices from buyers and sellers.

The ACCC would administer, and enforce compliance with, the price cap. The ACCC would also monitor and report on the impact of the price cap on electricity and gas markets, through its existing price inquiries into electricity and gas markets.

A review would be conducted following implementation, to ensure the price cap is having the intended effect and to consider whether it is necessary to alter the cap.

Bringing forward commencement of reforms to the ADGSM (Option A5)

On 25 October 2022, the Government announced the ADGSM would be reformed to give the Minister for Resources greater flexibility to protect domestic gas supplies. The reforms will strengthen the ADGSM by:

- moving from the current ‘calendar year’ model of activation to a quarterly cycle to improve speed and flexibility
- moving from the current ‘net deficit’ model of allocating volume shortfalls to exporters to:
 - splitting the TMSO equally across all exporters in the market in shortfall, and
 - making export permissions tradable between exporters
 - no longer including long-term foundational contracts underpinning investments in Australia’s gas industry as subject to the ADGSM.

The Government is consulting with companies subject to the ADGSM regulations and market advisory bodies on ADGSM reform implementation. Under the current implementation schedule, the reforms will commence 1 July 2023, which will enable an assessment of whether a gas shortfall is expected for the September 2023 quarter.

This option would bring forward the commencement date of these reforms from 1 July 2023 to 1 April 2023, enabling an assessment of whether a gas shortfall is expected for the September 2023 quarter, and could remain in effect for up to 12 months, to provide greater certainty about domestic gas supply security for the full 2023-24 financial year.

What is the likely net benefit of each option?

Basis of analysis

Due to the broad nature and complex interactions of the proposed reform options, a full quantitative cost benefit analysis has not been completed as a part of this impact assessment. Our assessment of the broader impacts of these options on aggregate prices involved quantitative analysis including modelling where possible to measure the impacts of individual proposed options.

Due to constraints around market sensitivity and the potential market impacts of communication prior to a decision being made, many of the impacts on specific stakeholders including industry have been examined using qualitative frameworks and assessments.

Each option is assessed against the objectives and principles of Government action which were highlighted at the start of the document and are considered in the context of impacts to individual stakeholder groups. The key impacts to stakeholder groups, in relation to the objectives and principles, are highlighted under each option.

Status quo (Option A0)

Under the status quo, there will be no additional regulatory costs or savings.

However, the status quo is unlikely to be a viable option to meet the Government’s energy price relief objectives. Under a status quo scenario, sustained elevated energy prices will likely continue to impact Australian households and businesses. Wholesale domestic prices are not expected to fall without intervention while global prices remain elevated. High energy prices across the economy would flow through to retail price rises for households and businesses. The status quo scenario may also result in an effective shortfall of gas supply due to an insufficient amount of gas being offered at affordable prices to domestic consumers.

The existing voluntary industry Code of Conduct is expected to have limited impact, with only a few gas producers being signatories to the voluntary code. The ACCC has raised concerns that the current code is broad, not capable of enforcement, lacks meaningful obligations on suppliers, contains ambiguous pricing provisions and does not provide for an appropriate dispute resolution process or penalties.

Table 2: Stakeholder Impacts of Option A0

Stakeholder group	Impact
Domestic gas producers	Nil.
LNG exporters	Nil.
Generators	Nil. Generators will continue to purchase fuel at higher prices and include this cost in their price bid.

Stakeholder group	Impact
Retail energy companies	Nil. Retail suppliers will continue to pay higher prices for fuel input and pass this on to consumers.
Domestic energy consumers (households, small business and industrial users)	Nil. Retail customers and industrial users will continue to purchase electricity at higher prices.
International trading partners and investors	Nil.

Option A1: Legislate a new framework for the making of gas market codes within the CCA, and prescribe a mandatory Code of Conduct for wholesale gas markets

Improving the operation of the voluntary Code of Conduct

Under this option, a mandatory Code of Conduct for wholesale gas markets can be prescribed under a new ‘gas market codes’ framework to be added to the CCA. This option could address current limitations in the voluntary code, as previously identified by the ACCC. The mandatory Code of Conduct would create well-defined and enforceable obligations that would apply to gas producers and customers.

In particular, the mandatory Code of Conduct would enhance the effectiveness and operation of the existing voluntary Code of Conduct, including strengthening requirements related to transparency, reporting, timeframes for negotiating and dispute resolution. In addition, the enforcement role of the ACCC and the availability of civil penalties is likely to provide the necessary incentive for gas producers and customers to comply with its terms, thereby supporting a more effective and efficient negotiating environment for all market participants.

The mandatory Code of Conduct would support increased transparency in the wholesale gas market, which would be beneficial for large gas users (such as commercial and industry customers and energy retailers) when negotiating supply contracts.

The mandatory Code of Conduct would also set out a longer-term framework to ensure reasonable cost-based pricing, which could be put in place alongside a price cap (see Option A4) and apply to both developed and undeveloped fields upon expiry of the price cap.

The benefits of the code are expected to flow through to downstream market participants in the supply chain and ultimately to households.

This option would require new legislation to be passed through parliament.

Increased regulatory burden

Gas producers may face a temporary increased regulatory burden under the mandatory Code of Conduct; however, this burden may be limited to the extent producers are already signatories to (or otherwise compliant with) the obligations in the voluntary Code of Conduct.

Industry would face higher regulatory burden under this option as it introduces greater enforcement action and binding arbitration processes.

Table 3: Stakeholder Impacts of Option A1

Stakeholder group	Impact
Domestic gas producers	The mandatory Code of Conduct would support increased transparency and competition in the wholesale gas market . Gas producers may also face an increased regulatory burden under the proposed mandatory Code of Conduct as they seek legal advice and transition their business practices to comply, however, this burden may be limited to the extent producers are already signatories to (or otherwise compliant with) the obligations in the voluntary Code of Conduct and to the extent that information transparency requirements will target information that is already available to producers.
LNG exporters	The mandatory Code of Conduct would support increased transparency and competition in the domestic wholesale gas market . LNG exporters may also face a temporary increased regulatory burden under the proposed mandatory Code of Conduct as they seek legal advice and transition their business practices to comply, however, this burden may be limited to the extent producers are already signatories to (or otherwise compliant with) the obligations in the voluntary code.
Generators	Generators would likely see lower wholesale gas prices through greater transparency and minimum standards in the negotiation of gas supply contracts.
Retail energy companies	Retailers would benefit to the extent they are able to access wholesale electricity at prices lower than the current wholesale market price .
Domestic energy consumers (households, small business and industrial users)	Industrial users would likely see lower wholesale prices through minimum standards in the negotiation of gas supply contracts. Retail customers would benefit from reduced growth in their energy bills .
International trading partners and investors	A mandatory Code of Conduct is unlikely to affect the volume of commodities exported to Australia’s trading partners . Increased transparency is unlikely to cause significant concerns for international investors , but investors may share the concerns of the LNG exporters about an increased regulatory burden.

Regulatory burden costings:

This option is expected to carry regulatory compliance costs, insofar as gas producers subject to the mandatory Code of Conduct will need to learn about their obligations under the code and adjust their processes to be compliant with the code. Additionally, this option opens the possibility of arbitration proceedings to resolve disputes where negotiations between gas producers and their customers break down. In the event arbitration is required, this would carry additional costs for both producers and their customers.

In total, it is expected that this option will create approximately \$800,000 in regulatory costs. See Appendix B for more detailed calculations and the assumptions made in these costings.

Table 4: Regulatory burden estimate (RBE) table (Option A1)

Average annual regulatory costs (from business as usual)				
Change in costs (\$ million)	Business	Community organisations	Individuals	Total change in costs
Total, by sector	\$803,459	-		\$803,459

Option A2: Prescribe a mandatory Code of Conduct for wholesale gas markets under the existing industry codes framework (Part IVB of the CCA)

Improving the operation of the voluntary Code of Conduct

Under this option, a mandatory Code of Conduct for wholesale gas markets can be prescribed which could address current limitations in the voluntary Code of Conduct, as previously identified by the ACCC. The mandatory Code of Conduct would create well-defined and enforceable obligations that would apply to gas producers and customers.

In particular, the mandatory Code of Conduct would enhance the effectiveness and operation of the existing voluntary code, including strengthening requirements related to transparency, reporting, timeframes for negotiating and dispute resolution. The maximum penalties under this option would be limited to 600 penalty units (around \$133,000), significantly lower than those available for other breaches of the CCA (up to \$50 million or more) and insufficient to provide a strong deterrent against non-compliance, where the benefits of non-compliance could be millions of dollars.

The mandatory Code of Conduct would support increased transparency in the wholesale gas market, which would be beneficial for large gas users (such as commercial and industry customers and energy retailers) when negotiating supply contracts.

This option would be faster to implement compared to Option A1 as it would not require new legislation to be passed through the parliament.

Increased regulatory burden

Gas producers may face an increased regulatory burden under the mandatory Code of Conduct; however, this burden may be limited to the extent producers are already signatories to (or otherwise compliant with) the obligations in the voluntary Code of Conduct.

Under this option, industry would face less regulatory burden compared to Option A1 due to reduced enforcement and lack of binding arbitration requirements.

Table 5: Stakeholder Impacts of Option A2

Stakeholder group	Impact
Domestic gas producers	The mandatory Code of Conduct would support increased transparency in the wholesale gas market . Gas producers may also face a temporary increased regulatory burden under the proposed mandatory Code of Conduct as they seek legal advice and transition their business practices to comply, however, this burden may be limited to the extent producers are already signatories to (or otherwise compliant with) the obligations in the voluntary Code of Conduct and to the extent that information transparency requirements will target information that is already available to producers.
LNG exporters	The mandatory Code of Conduct would support increased transparency in the wholesale gas market . LNG exporters may also face a temporary increased regulatory burden under the proposed mandatory Code of Conduct as they seek legal advice and transition their business practices to comply, however, this burden may be limited to the extent producers are already signatories to (or otherwise compliant with) the obligations in the voluntary Code of Conduct.
Generators	Generators would likely see lower wholesale prices through greater transparency and minimum standards in the negotiation of gas supply contracts.
Retail energy companies	Retailers would benefit to the extent they are able to access wholesale electricity at prices lower than the current wholesale market price .
Domestic energy consumers (households, small business and industrial users)	Industrial users would likely see lower wholesale prices through greater transparency and minimum standards in the negotiation of gas supply contracts. Retail customers would benefit from reduced growth in their energy bills .
International trading partners and investors	A mandatory Code of Conduct is unlikely to affect the volume of commodities exported to Australia’s trading partners . Increased transparency is unlikely to cause significant concerns for international investors , but investors may share the concerns of the LNG exporters about an increased regulatory burden.

Regulatory burden costings:

This option is expected to carry regulatory compliance costs, insofar as gas producers subject to the mandatory Code of Conduct will need to learn about their obligations under the code and adjust their processes to be compliant with the code.

In total, it is expected that this option will create approximately \$370,000 in regulatory costs. See Appendix B for more detailed calculations and the assumptions made in these costings.

Table 6: Regulatory burden estimate (RBE) table (Option A2)

Average annual regulatory costs (from business as usual)				
Change in costs (\$ million)	Business	Community organisations	Individuals	Total change in costs
Total, by sector	\$371,459			\$371,459

**Option A3 – Work with industry to strengthen the existing voluntary Code of Conduct
Improving the operation of the voluntary Code of Conduct**

Under this option, the Government would work with industry to increase participation in and amend the existing voluntary Code of Conduct for wholesale gas markets to address current limitations in the voluntary Code of Conduct, as previously identified by the ACCC. The extent to which this option would meet the objectives set out in this document is dependent on the results of any negotiations and uptake by industry members.

Table 7: Stakeholder Impacts of Option A3

Stakeholder group	Impact
Domestic gas producers	Minimal but some potential impact on the processes for wholesale pricing if producers opt in to a stronger voluntary code. Any additional uptake would be voluntary.
LNG exporters	Minimal but some potential impact on the processes for wholesale pricing if LNG exporters opt in to a stronger voluntary code.
Generators	Likely nil or minimal impact on domestic fuel prices. Generators will continue to purchase fuel at higher prices and include this cost in their price bid.
Retail energy companies	Likely nil or minimal impact on domestic energy prices. Retail suppliers will continue to pay higher prices for electricity and pass this on to consumers.
Domestic energy consumers (households, small business and industrial users)	Industrial users are unlikely to see significantly lower wholesale prices under this option. Likely nil or minimal impact on retail energy bills. Retail customers and industrial users will continue to purchase electricity at higher prices.
International trading partners and investors	An amended voluntary code is unlikely to affect the volume of commodities exported to Australia’s trading partners or cause significant concerns for international investors , but investors may share the concerns of the LNG exporters about an increased regulatory burden.

Regulatory burden costings:

This option does not impose any regulatory burden as businesses are not compelled to comply with a voluntary Code of Conduct.

Option A4: Temporary 12-month gas price cap

Price reduction benefits

The impacts of a price cap on prices and on stakeholders is dependent on the level at which it is set – a cap which is too high will not put downward pressure on prices, while a cap which is too low will affect investor confidence and the viability of future investments. Based on their analysis, the ACCC has advised that it considers a price of \$12/GJ reflects the costs of gas production, including a reasonable return on capital for gas sourced from developed fields capable of supply during the period in which the emergency price rule is of application (noting that the costs associated with undeveloped fields may be higher and are therefore excluded from the cap).

In arriving at this price, the ACCC considered the prices that were offered on the east coast in 2021, for supply in 2023, prior to international prices increasing in late 2021 and data on the costs of gas production. Over 2021, there were 289 domestic offers made by producers and retailers, with 96 per cent of offers made below \$12/GJ and an average price of \$9.20/GJ.

While the level of a final price cap would be subject to consultation, we have assumed this price of \$12/GJ reflects a fair price and proceeded with the Impact Analysis on this basis.

Assuming, for the purposes of the modelling, that under the cap new contracts are priced at \$12/GJ from 1 January 2023, Treasury estimates that a temporary cap on uncontracted gas will reduce retail gas price growth from 20 per cent to 18 per cent in 2022-23, and from 20 per cent to 4 per cent in 2023-24. The cap will only apply to available supply from developed fields to limit impacts on future investment decisions. This is a 2-percentage point decline in the expected increase in gas prices in 2022-23, and a 16-percentage point decline in 2023-24.

Major gas customers would be able to access gas at lower prices compared to the current market price, provided there is sufficient supply at the capped price. The benefits of the price cap are also expected to flow through to wholesale electricity prices, and ultimately to retail electricity prices, slowing the growth of energy bills for Australian households and businesses.

The price cap would also help to put downward pressure on electricity spot prices by providing a lower cost source of uncontracted gas, which are relied on by gas-powered electricity generators. While the temporary price cap on its own may not be sufficient to influence the price of electricity contracts for future years, it mitigates short-term risks associated with wholesale electricity prices and complements other longer-term measures explored in this Impact Analysis.

The lower domestic wholesale gas prices would significantly benefit large and intensive energy users reliant on gas for their production processes (e.g. plastics, fertiliser manufacturers). The lower production costs would have downstream benefits for any users of goods produced by these firms. A reduction of domestic gas prices would also improve the international competitiveness of these firms operating in Australia.

Implementation of a price cap would need to be carefully managed to ensure Australia maintains its positive relationships with key trading and investment partners and to continue to progress towards its renewable energy and emissions reduction goals. A temporary price cap is less likely to have a dampening effect on investor confidence, distort investment incentives for producers, generators and consumers, and less likely to pose risks to domestic supply relative to an ongoing price cap.

Table 8: Stakeholder Impacts of Option A4

Stakeholder group	Impact
Domestic gas producers	Where gas producers supply gas to domestic wholesale markets through bilateral contracts, they would be expected to receive lower prices compared with what they could otherwise secure, for example on the export market for gas exporters, or in the absence of price regulation.
LNG exporters	A domestic price cap is unlikely to have other significant impacts on LNG exporters, except where they are also producers and selling to the domestic market. In this case, the impacts for their domestic interests would be the same as above.
Generators	Major gas customers such as generators would benefit to the extent that they are able to access gas at prices lower than the current wholesale market price.
Retail energy companies	Retailers would likely benefit to the extent they are able to access wholesale electricity at prices lower than the current wholesale market price.
Domestic energy consumers (households, small business and industrial users)	Major gas customers such as industrial users would benefit to the extent they are able to access gas at prices lower than the current wholesale market price. Retail customers would benefit from reduced growth in their energy bills.
International trading partners and investors	A temporary domestic price cap on gas need not affect the volume of commodities exported to Australia’s trading partners. A temporary, appropriately set price cap in response to an international crisis is also unlikely to cause significant concerns for international investors, to the extent that they are affected by reduced earnings from domestic gas sales.

Regulatory burden costings:

This option is expected to carry regulatory compliance costs, insofar as the introduction of a price cap will require gas producers to adjust their offers to the market to comply with the price cap. A similar exercise will be required when the price cap expires 12 months later.

In total, it is expected that this option will create approximately \$160,000 in regulatory costs. See Appendix B for more detailed calculations and the assumptions made in these costings.

Table 9: Regulatory burden estimate (RBE) table (Option A4)

Average annual regulatory costs (from business as usual)				
Change in costs (\$ million)	Business	Community organisations	Individuals	Total change in costs
Total, by sector	\$158,889			\$158,889

Option A5: Bringing forward commencement of reforms to the ADGSM

Bringing forward the implementation of the ADGSM reforms from July 2023 to April 2023 would allow earlier assessment of whether a gas shortfall is expected to occur.

Impact of quarterly ADGSM activation

Quarterly activation will lead to more flexible decision-making and shorter activation timelines, improving the Minister's ability to address shortfall risks. Increased flexibility allows the Minister to quickly enact export controls and more often, alleviating shortfalls in a shorter timeframe and putting downward pressure on gas prices earlier. It will also allow the Minister to assess, determine and communicate assessment of a projected shortfall on a regular basis, and can increase overall system transparency if information is collated and shared.

However, more frequent decision-making and shorter activation timelines will increase system complexity. Government and other agencies need to be prepared to provide information and assess the possibility of a projected shortfall at multiple times in a year and if necessary, allocate export controls.

Impact of splitting the TMSO equally across all LNG exporters

Splitting the TMSO equally across all LNG exporters will give greater certainty that in the event of the ADGSM being activated, it would restrict LNG exports by the full amount of the anticipated domestic shortfall.

Changing the TMSO methodology to an equal split approach could reduce potential impacts to trusted trading partners, as this approach is expected to reduce the exposure of a net deficit exporter's long-term export contracts to potential export restrictions. This approach would also require minimal changes to the existing ADGSM arrangements, making it relatively simple to implement and administer.

Implementing tradeable export permissions reduces the economic cost to the overall system as the net deficit exporter no longer needs to incur additional costs to meet long-term contracts while complying with export controls.

Full consideration of these reforms is outlined in the ADGSM Regulatory Impact Statement.

Impact of bringing forward the commencement date of reforms by one quarter

Implementing the ADGSM reforms on an expedited schedule will bring the benefits outlined above one quarter earlier. Condensing the implementation period for reforms, when other market reforms may be implemented simultaneously, will increase the costs, complexity and burden faced by industry, and reduces the period for consultation. Key design features of the reforms, in particular the tradability of export permissions among producers will require careful consideration alongside the \$12/GJ price cap to avoid any unintended consequences. Expedited implementation will support stability and security for domestic gas users.

Table 10: Stakeholder Impacts of Option A5

Stakeholder group	Impact
Domestic gas producers	The regulatory impact on domestic gas producers is unchanged from the recent, previously analysed reforms to the ADGSM - Refining the Australian Domestic Gas Security Mechanism ¹¹ , with the main impact of the measure bringing forward these reforms (OBPR22-02706 refers).
LNG exporters	Increases in regulatory impact on LNG exporters are expected to be minimal but may increase as less time is available to settle key design parameters. Baseline impacts of the reforms were considered through <i>ADGSM - Refining the Australian Domestic Gas Security Mechanism</i> (OBPR22-02706 refers).
Generators	Nil.
Retail energy companies	Nil.
Domestic energy consumers (households, small business and industrial users)	Nil.
International trading partners and investors	Bringing forward the ADGSM reforms may cause concerns for Australia’s trading partners and international investors , to the extent it raises concerns that the ADGSM may be triggered sooner.

Regulatory burden costings:

This option does not impose any regulatory costs as any regulatory burden from the ADGSM reforms are also present under the status quo base case.

Comparison of Options against Objectives

Table 11 below compares the different options considered and assesses them against the objectives and principles outlined above. Based on an assessment of each option against the objectives and compared to the status quo scenario, the options are colour coded in a ‘traffic light’ system according to the following key:

Key	
	Improvement against status quo
	Negligible against status quo
	Deterioration against status quo
	Status Quo

This tool is helpful in comparing the different options directly and to determine whether a combination of options would achieve the desired outcomes.

¹¹ [ADGSM - Refining the...~https://oia.pmc.gov.au/published-impact-analyses-and-reports/adgsm-refining-australian-domestic-gas-security-mechanism](https://oia.pmc.gov.au/published-impact-analyses-and-reports/adgsm-refining-australian-domestic-gas-security-mechanism)

Table 11: Summary of assessment of all options against objectives

	A0 – Status quo	A1 – Mandatory Code of Conduct (amended legislation)	A2 – Mandatory Code of Conduct (existing legislation)	A3 – Strengthened voluntary Code of Conduct	A4 – Gas Price Cap (1 year)	A5 – Expedited ADGSM Reforms
Downward pressure on wholesale electricity prices	The status quo is likely to see continued pressure on wholesale electricity prices.	Provides ACCC additional powers to enforce price decreases from producers to retailers	Existing legislation carries lower penalties compared to amended legislation	No additional powers to pass savings down energy supply chain	Capping the price of gas has a direct effect on the price of electricity, as gas is often the price setter.	Ample supply means price is not driven up and allows domestic price mechanisms to operate effectively
Downward pressure on consumer bills	The status quo option will not change the course of energy bills in the short term.	Enforces price decreases from producers to retailers, does not guarantee reduced growth in prices	Existing legislation carries lower penalties compared to amended legislation	No additional powers to pass savings down energy supply chain	A price cap is applied to contracts and will have an effect in the short term.	Allows Government to secure domestic supply in short term, but not price
Enhances transparency and competitive pricing	The status quo option does not provide any mechanism to enhance transparency or competitive pricing	Increases obligations on producers to be transparent and competitive	Increase obligations on producers to be transparent and competitive	Improves obligations on producers to be transparent and competitive, subjected to industry negotiation	Transparently sets a ceiling but has no effect of competition	Expediting reforms will accelerate the mechanism’s efficiency and increased transparency
Minimise unintended consequences	The status quo option will not have any associated unintended consequences	Regulates producers’ behaviour, based on existing obligations	Regulates producers’ behaviour, based on existing obligations	Minimal changes producers’ behaviour, based on existing obligations	Short term cap, mitigates unintended consequences	Expedited reforms increase potential for unintended consequences
Maintain incentives for investment	The status quo option will not cause any distortions to investment.	A mandatory code is unlikely to impact on investment incentives	A mandatory code is unlikely to impact on investment incentives	A voluntary code is unlikely to impact on investment incentives	Short term cap mitigates potential impacts on investment incentives for producers, generators, and consumers.	Expediting the ADGSM reforms will provide for earlier efficiency and less distortionary effects
Ensure domestic electricity and fuel supply	The status quo will not provide any further mechanisms to ensure sufficient supply.	Will not provide further mechanisms to ensure supply	Will not provide further mechanisms to ensure supply	Will not provide further mechanisms to ensure supply	Risk a cap could incentivise domestic supplies to divert supply to storage or the export market	Allows Government to quickly, flexibly, and efficiently secure supply
Minimise impacts on international trading partners and investment.	The status quo has no associated impacts on international trading partners and investment	A mandatory code has minimal impacts on international trading partners and investment	A mandatory code has minimal impacts on international trading partners and investment	A voluntary code has minimal impacts on international trading partners and investment	A domestic price cap has limited impacts on international trading partners and investment	Intervention affects exporters sooner than anticipated, impacting international trading partners and investment.
Minimise implementation costs and complexity	The status quo does not have any implementation costs.	A mandatory code carries some implementation costs and complexity (\$803,459 per year)	A mandatory code carries some implementation costs and complexity (\$371,459 per year)	Minimal implementation costs and complexity (status quo) (nil regulatory burden if voluntary)	Some costs for government (enforcement) and for industry (compliance) (\$158,889 per year)	Minimal additional complexity and cost compared to reforms scheduled to commence July 2023 (nil regulatory burden)

Consultation

The market sensitivities associated with the measures considered in this Impact Analysis, as well as the urgency in which they need to be developed and implemented reduced the viability of extensive, public consultation on specific options for Government action thus far. There will however be future opportunity to consult stakeholders prior to the implementation of some of the options highlighted in this Impact Analysis.

Firstly, a brief, targeted consultation on the \$12/GJ cap is expected once the primary amendments are in place – this will enable the Government to confirm this is the correct level for the cap. The price cap will reflect the key costs of gas production including a reasonable return on capital. The ACCC has suggested this could be \$12/GJ, but this will be confirmed through this brief consultation period.

Further, the mandatory Code of Conduct is expected to be released for public consultation before implementation. The review mechanisms for the options considered, which are described more extensively later in this document, will also provide opportunity to engage with stakeholders in the future. The Government also previously held consultations on reforms to the ADGSM to improve the mechanism and enable it to be used at short notice in the event of a forecast gas shortfall, which are currently scheduled to be introduced on 1 July 2023. Stakeholder consultation on the design of the ADGSM reforms before implementation will also be necessary to avoid early design flaws and any unintended consequences with other options to provide energy price relief.

It is further proposed that a review of the price cap be completed after implementation, to ensure the price cap is having the intended effect and consider whether it is necessary to adjust or extend the cap. It is proposed a review of the mandatory Code of Conduct also be completed to allow for any necessary refinements or improvements.

Further to the previous consultation on the ADGSM, and opportunities for future consultation highlighted above, Australian Government departments regularly engage with a range of government agencies, industry bodies and stakeholders to discuss their views on the energy market dynamics. Industry bodies and stakeholders include gas and electricity producers and retailers, market and industry regulators and consumer groups.

In the context of broad cost-of-living pressures, Energy Ministers committed at the 28 October 2022 Energy Ministers Meeting to consider all options to bring down power prices for households and businesses, and the Government has publicly stated that it is considering options to bring down energy prices. Following Government announcements that options were being considered to bring down energy prices, many stakeholders sought meetings with the Government in November 2022 through the regular engagement process. This included meeting requests with senior public officials or writing to the Minister for Climate Change and Energy for views on the energy market.

Through regular engagement channels, stakeholders provided views on the drivers of current and forecast high energy prices, energy market dynamics and their views on policy options for addressing rising energy prices. This included stakeholder views on what Government responses would best lower costs for energy market participants (including consumers), would have the most immediate impact, and ensures energy producers and generators remain profitable. Stakeholders also provided views on potential unintended consequences of responses highlighted in the media as potential

Government courses of action. For example, some producers voiced preferences for certain types of policy responses – some preferred price caps on electricity and input fuels, with some noting that the Heads of Agreement was the optimal mechanism through which to implement a price control.

These discussions provided insights into the viability of the options raised by stakeholders – some of which are options highlighted in this Impact Analysis. These views assisted in highlighting potential unintended consequences of some of the options considered. They have also provided insights into potential industry responses, the viability of swift implementation and their likely success.

The Government has also had consistent discussions with the ACCC, the AER and, to a lesser extent, AEMO, regarding regulating, monitoring, and reporting of the energy market. Some of the options highlighted in this Impact Analysis require these entities to monitor and report on realised outcomes. Engagement with these entities, particular with the ACCC, has ensured that there is capacity to complete the monitoring and reporting requirements.

As discussed above, there will be further opportunity for consultation with stakeholders prior to implementation of the mandatory Code of Contact and proposed price cap for gas.

Option selection

Following analysis of the likely net benefits of each option and considering the objectives and principles of Government action outlined above, this Impact Analysis recommends options A1, A4 and A5 for implementation to address current and forecast future energy prices. The assessment conducted on the options is summarised at Table 11 above. As discussed above, the assessment was conducted using both quantitative and qualitative methods. Where there are expected impacts to the prices faced by consumers, forecasting conducted by the Treasury was used to quantify these impacts.

The Government considers this combination of three responses presents the greatest benefit to Australia with regard to the objectives and principles and should progress to implementation. These are:

- A1 – Legislate a new framework for the making of gas market codes within CCA, and prescribe a mandatory Code of Conduct for wholesale gas markets
- A4 – Temporary 12-month gas price cap
- A5 – Bringing forward commencement of reforms to the ADGSM.

These policies are being progressed as a suite because they work in concert to mitigate the risks present in individual policies implemented in isolation. They provide price certainty in the short term, will enable behavioural standards in negotiations to be enforced, ensure supply to the domestic market, and place obligations on both sellers and buyers to act in good faith.

Further, out of the options considered, these policies are likely to achieve the greatest number of Government action objectives in combination, including minimising potential unintended consequences, largely resulting in either a moderate or significant improvement against the status quo.

Through a mandatory Code of Conduct, options A1 and A2 would increase obligations on gas producers by setting minimum behavioural standards, whereas option A3 would only seek to improve existing obligations, without a mechanism to mandate them. Compared to options A2 and A3, option A1 is also likely to have a greater impact on putting downward pressure on electricity prices, by providing the ACCC enforcement powers to ensure that price decreases flow through to consumers. For these reasons, and as demonstrated in the above comparative analysis at Table 11, option A1 is preferred to options A2 and A3. The mandatory Code of Conduct will be key to transparent and competitive pricing in the medium term, giving the ACCC enforcement powers and clarifying obligations for producers established in the voluntary code. The mandatory Code of Conduct will set minimum behavioural standards based on the existing voluntary Code of Conduct and the advice of the ACCC. In a competitive market, the ACCC expects the benefits of the mandatory Code of Conduct will flow through to downstream and related markets, eventually. It will also allow the ACCC to monitor and report on the compliance with the price cap, noting this will somewhat increase regulatory burden. Overall, this establishes a framework to ensure a reasonable price for gas in a sustainable way over the medium to long-term.

While variations on option A4 were considered to reduce gas prices and slow increases in consumer bills in the short term. An extended price cap may be more likely to distort investment incentives as it is in place for a longer period. In the short term, the price cap will put downward pressure on the price of contracts and wholesale electricity prices. The cap has been recommended by the ACCC to reflect the costs of gas production, including a reasonable return on capital, for gas sourced from developed fields. Enforcing a price cap may incentivise producers to store gas or produce less as it is less profitable, noting the ACCC's advice that 96 per cent of domestic contracts in 2021 were offered at less than the proposed cap.

Finally, under option A5, bringing forward reforms to the ADGSM will provide the Government more flexibility sooner, by allowing the trigger to activate on a quarterly basis. While this increases the complexity of the scheme, it will allow ministers to be more responsive to foreseeable gas shortfalls. This will ensure the necessary gas supply to enable both the mandatory Code of Conduct and the price cap to work effectively. Additionally, changes to the distribution of security obligations and introducing the ability to trade these obligations will make the mechanism more efficient and minimise distortions in investment.

This set of combined options has also been informed through consultation across government departments and agencies. Implementation for options A1 and A4 will depend on the timing of legislative and parliamentary processes, while option A5 would come into effect from 1 April 2023.

Stakeholder Feedback

As noted above, the market sensitivities associated with the measures considered in this Impact Analysis, as well as the urgency in which they need to be developed and implemented reduced the viability of extensive, public consultation on specific options for Government action thus far.

Engagement with stakeholders who approached the Government through usual stakeholder engagement avenues highlighted the risks and sensitivities of the considered measures. Of particular note has been the unintended market effects of price caps, and the varied opinions on how to best to apply any cap.

There will be future opportunity to consult stakeholders prior to the implementation of some of the options highlighted in this Impact Analysis. Namely, the mandatory Code of Conduct will be released for public consultation, and there will be a consultation period on the \$12/GJ cap on wholesale gas for 2023. This includes further consultation on the price cap to balance a reasonable return to suppliers and ensure supply on reasonable terms for purchasers.

Implementing the suite of proposed options, and negotiating complementary measures with the states, will mitigate concerns raised by stakeholders, while delivering the intended benefits to consumers and purchasers.

How will you implement and evaluate your chosen option?

The following section describes the anticipated implementation paths as well as milestones for review or course-correction. Further, the key risks associated with the recommended options are also identified below alongside strategies to mitigate these risks.

Given the suite of options identified, isolating the impacts of specific options for evaluation may be challenging. The success of the suite of options could be collectively evaluated using AER and ACCC data on wholesale and retail energy prices to monitor if there are reductions to consumer energy prices and positive shifts in behaviour of energy market participants following introduction of the policies. Energy retail prices can also be compared to expected future prices increases forecast in the October 2022-23 Budget to assess the relative success of the recommended policies.

Option A1: Legislate a new framework for the making of gas market codes within the CCA, and prescribe a mandatory Code of Conduct for wholesale gas markets

A mandatory Code of Conduct containing the recommended stronger provisions would create a statutory base for improved transparency and reporting. The timeframes for the implementation of a mandatory Code of Conduct are all subject to the passing of legislation.

Implementation - Implementation of this option will require legislative amendments to the CCA. Amendments to primary legislation would be made to establish an enabling framework more suited to this purpose, including imposing penalties for breaching standards or obligations contained in the code. This framework could be drafted broadly, allowing flexibility to develop mandatory codes for other energy markets.

Following preliminary legislation, the mandatory Code of Conduct could then be released for public consultation, after which the code could be implemented through subordinate instruments.

A review is also proposed for the mandatory Code of Conduct after implementation to allow for any necessary refinements or improvements. Compliance with all requirements of the code would be monitored by the ACCC. An evaluation of the code could be informed by the usual monitoring and reporting of energy market participant behaviour conducted by the ACCC – for example through the ACCC’s Gas Inquiry Reports. For the mandatory Code of Conduct to be considered successful, a positive shift in behaviour would be observed from gas suppliers in negotiating wholesale gas contracts.

Further, the ACCC would use its existing powers as well as being provided with stronger supporting powers under the CCA to take enforcement action where electricity retailers fail to reasonably adjust their electricity retail offers to reflect supply chain cost savings.

The steps for implementation of the mandatory Code of Conduct are as follows:

1. Release of consultation paper to inform design of the code.
2. Primary amendments to legislate a framework for implementing the code.
3. Draft code released for public consultation.
4. Implementation of the code through a subordinate instrument.

5. Review of the mandatory Code of Conduct to be completed after implementation to allow for any necessary refinements or improvements. This review would cover the effectiveness of the code, including whether it is achieving the desired outcomes and offer an opportunity to course correct.

Table 12: Risk mitigation for Option A1

Risk	Assessment	Mitigation steps
Mandatory Code of Conduct is ineffective at addressing the problem	<p>Likelihood: Moderate – A mandatory Code of Conduct only addresses some of the issues driving price and supply issues in energy markets.</p> <p>Impact: High – Not resolving issues will see high energy prices persist.</p>	<ul style="list-style-type: none"> • Other measures (including those proposed in this IA) are taken to address problem. • ACCC monitor and enforce compliance. • Review of Code of Conduct to address performance, with additional refinements implemented following review.
Lack of support from stakeholders	<p>Likelihood: Moderate – Industry may oppose mandatory Code of Conduct.</p> <p>Impact: Moderate – Impacts on continuing engagement between industry and Government to address price and supply issues.</p>	<ul style="list-style-type: none"> • Mandatory Code of Conduct is formalising existing voluntary Code of Conduct. • Review of mandatory Code of Conduct to address performance, with additional refinements implemented following review.
ACCC lack capability to monitor and enforce mandatory Code of Conduct	<p>Likelihood: Low – ACCC are an established regulator operating under an existing framework.</p> <p>Impact: High – Failure to monitor and enforce mandatory Code of Conduct will see non-compliance.</p>	<ul style="list-style-type: none"> • ACCC is utilising its existing capability and powers and receiving additional resourcing (including for its ongoing Gas Inquiry) as announced previous by Government. • Additional powers are being provided through the preferred option.

Option A4: Gas price cap

A price cap on wholesale gas will be set at a level which reflects the costs of gas production, including a reasonable return on capital for gas available for immediate supply from undeveloped fields. Similarly, to the mandatory Code of Conduct, timeframes for the implementation of a price cap on wholesale gas are all subject to the passing of legislation.

Legislation will be required to implement the price cap on wholesale gas, likely through amendments to the CCA. Legislation would require that gas which is sold via bilateral contract at the wholesale level and sourced from developed gas fields be sold at a ‘reasonable price’, with reasonable prices

deemed to be those falling below a cap which would apply on a temporary basis for 12 months. Amendments to ensure the enforceability of the price cap, including imposing penalties for supplying gas above the price cap or breaching standards or obligations contained in the code would also be made.

Following legislative changes, a brief, targeted consultation on the level of the price cap will provide certainty that \$12/GJ accurately reflects producers’ current costs and a reasonable rate of return. The price cap can then be implemented through subordinate instruments as soon as possible.

The price cap, would be reviewed after implementation to ensure it is having the intended effect and consider whether it is necessary to adjust or extend the cap. The effectiveness of the price cap will be measured by comparing the realised retail energy prices to those forecast by Treasury for the status quo scenario. However, it is important to note the challenges in isolating the impact of the price cap alone, given the broader range of factors that can influence retail energy prices.

The timeframes and the steps for implementation of the price cap for gas are as follows:

1. Release of consultation paper to inform design of the price cap.
2. Legislation to implement the price cap.
3. A review of the price cap will be completed after 6 months to ensure the price cap is having the intended effect and consider whether it is necessary to adjust or extend the cap. The review would also examine any unintended effects and offer an opportunity to course correct.

Table 13: Risk mitigation for Option A4

Risk	Assessment	Mitigation steps
Price cap is not set at right level	<p>Likelihood: Moderate – Assessment of price based off long-term production history and industry consultation.</p> <p>Impact: High – Gas producers would not receive appropriate returns or consumers will pay higher than necessary prices.</p>	<ul style="list-style-type: none"> • Initial public consultation on level of price cap (including transparency in setting cap). • Review of price cap after implementation. • Only applies to developed gas fields where cost of production is known. • Initial price cap is set for 12 months.
Deters future investment	<p>Likelihood: Moderate – Investors may be wary to make future investments given the precedent value and cap on potential profits.</p> <p>Impact: High – Reduces investment and may lead to a long-term reduction in gas supplies provided domestically.</p>	<ul style="list-style-type: none"> • Initial price cap is set for 12 months. • Only applies to developed gas fields. • Price cap is set at a level that allows reasonable profit.

Risk	Assessment	Mitigation steps
Price cap is ineffective at addressing the problem	<p>Likelihood: Low – A price cap on gas directly addresses one of the leading causes of the current price shock.</p> <p>Impact: High – Consumers continue to pay a higher than necessary price for their energy.</p>	<ul style="list-style-type: none"> • Other measures (including those proposed in this RIS) are taken to address problem. • Evaluation of impact by comparing realised energy prices against Treasury forecasts. • AER monitoring to ensure price reduction is passed on to consumers. • Review of price cap after implementation.
Supply is diverted to export markets or storage	<p>Likelihood: Low – Producers have an incentive to divert to higher-price export markets or store for later use once price cap expires.</p> <p>Impact: High – Diversion to export markets risks an energy shortfall.</p>	<ul style="list-style-type: none"> • Reformed ADGSM will prevent supply shortfall. • Price cap set to allow reasonable profit. • Initial price cap is set for 12 months.
Risk to Australia’s reputation as an investment destination.	<p>Likelihood: Moderate – Investors may consider a temporary price cap may be a sign of future Government intervention.</p> <p>Impact: Low – Investors may be less willing to make the significant investments needed to support the energy transition.</p>	<ul style="list-style-type: none"> • Initial price cap is set for 12 months. • Price cap set to allow reasonable profit. • Price cap only applies to developed gas fields.
Unintended or unforeseen consequences of introducing price cap	<p>Likelihood: Moderate – Introducing a price cap would be a significant change to the operation of the market.</p> <p>Impact: High – A price cap could have short- or long-term impact of the operation of market.</p>	<ul style="list-style-type: none"> • Initial price cap is set for 12 months. • Price cap set to allow reasonable profit. • Price cap only applies to developed fields.

Option A5: Bringing forward commencement of reforms to the ADGSM

The bringing forward of the ADGSM reforms already scheduled for commencement in July 2023 will complement the price cap on east-coast wholesale gas supplied via bilateral trades, by ensuring domestic supply in the face of price controls in the domestic market.

The implementation of reforms to the ADGSM, as well as evaluation methods, are highlighted in the Impact Analysis OBPR22-02706 completed in October 2022. Delivering the recommended changes to the ADGSM will require:

- Implementation of changes to the mechanism, including amending legislation

- Ongoing monitoring, evaluation, and review, both of implemented changes and broader domestic gas security.

As a ‘backstop’ measure that is only activated under certain conditions, the ADGSM does not require the same level of monitoring and evaluation of day-to-day operation and impacts as other types of government mechanisms. As such, the mechanism would primarily be monitored and evaluated in two ways:

- Temporary monitoring of the performance of the mechanism during periods it is activated
- Periodic reviews of the longer-run performance of the mechanism (e.g., as a backstop to encourage supplier behaviour).

To this end, a review has been scheduled for 2025, as part of the extension of the ADGSM until 2030. In the review, the following matters must be addressed:

- the effectiveness and efficiency of the ADGSM, including its ability to ensure sufficient supply of natural gas for Australian customers and with a minimum of disruption to Australia’s LNG industry.
- the impact of the ADGSM on the competitiveness of Australia’s LNG industry, and Australia’s international reputation for quality and reliability and as an investment destination.
- the impact of the ADGSM on the development of new and additional gas resources and market functions.
- whether improvements can be made to the ADGSM and whether there are appropriate alternative mechanisms to achieve the same objectives that the ADGSM legislation hopes to achieve.
- whether the ADGSM legislation should be amended or repealed.
- any other considerations the Minister for Resources considers relevant.

Risk identification and mitigation were considered as part of the impact assessment for the ADGSM reforms completed in October 2022.

Appendix A: Further Background on the NEM and ADGSM

The National Electricity Market (NEM)

The NEM is a wholesale electricity market connecting the six eastern and southern states and territories. WA is not connected to the NEM as they have their own electricity systems and are governed under separate regulatory arrangements.

How the NEM Spot Market Works

Generators offer to supply the market with a certain volume of electricity for a bid price for 5-minute periods. AEMO accepts those offers from the lowest priced generator up until enough volume has been secured to meet the demand for that time interval.

The price of the last highest-priced marginal offer accepted in each 5-minute interval sets the market price. This is known as the price setter and every generator whose energy is dispatched is paid that same 'dispatch' price.

The National Electricity Rules (NER) sets a market price cap and cumulative price threshold for the NEM.

The market price cap is the maximum price that can be reached on the spot market during any dispatch and trading interval. The cumulative price threshold is the maximum price across seven days' worth of trade.

Table 14: Energy Price Thresholds

The market price cap and cumulative price threshold for the 2022-23 financial year is:

1 July 2022 to 30 June 2023	
Market price cap	\$15,500 / MWh
Cumulative price threshold	\$1,398,100

Source: AEMC Feb 2022 media release

To manage the risks associated with the volatility in the spot market price energy retailers and many large energy users may instead purchase energy through the 'contract or Power Purchase Agreement (PPA) market' – where energy retailers and large industrial businesses contract directly with generators to buy particular volumes of energy for an agreed fixed price. Renewable generators also enter into PPAs to give themselves revenue certainty.

Electricity providers within the NEM:

There are fifty-four retail brands that sell energy to residential or small business customers in southern and eastern Australia. Of these, the retail brands of 3 businesses – AGL Energy, Origin Energy and EnergyAustralia (the 'big 3') – supply 64 per cent of small electricity customers. These businesses are vertically integrated.

NSW has the largest number of active electricity retailers (46), followed by Queensland (45), South Australia (35) and Victoria (30). Electricity markets in south-east Queensland, NSW, Victoria and South Australia have several competitive characteristics, including a diversity of sellers making offers, reduced exposure to government owned generation and retail businesses, intensive marketing activity and customer switching.

Vertical integration:

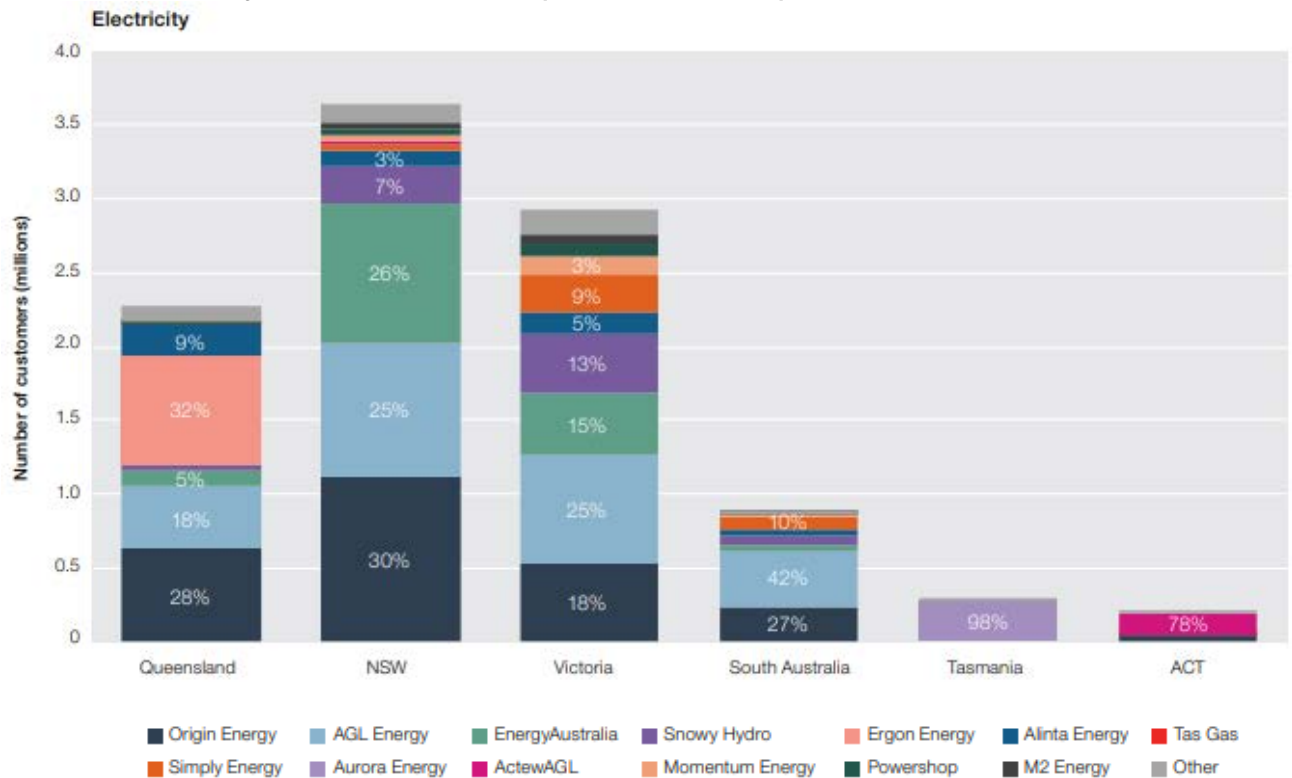
Generators and retailers can manage their exposure to volatile wholesale prices using derivatives or power purchase agreements to fix prices for which they will respectively generate and purchase electricity for given future periods. Alternatively, some participants internally manage wholesale price risk through vertical integration – operating as both a generator and a retailer effectively being both a receiver and payer of wholesale prices.

Vertically integrated firms have less need to hedge their positions in futures (derivatives) markets compared to non-integrated ones. This strategy may be efficient for that business but can reduce overall liquidity in derivatives offered by generators, posing a competitive disadvantage and barrier to entry or expansion for retailers that are not vertically integrated.

Typically, vertically integrated ‘gentailers’ are largely but imperfectly naturally hedged. Their generation profile can be managed knowing their customer demand profile. For this reason, gentailers participate in contract markets to manage outstanding residual exposures between their generation and customer loads, although usually to a lesser extent than standalone generators and retailers do.

Generators who are also retailers in the NEM include AGL Energy, Origin Energy, EnergyAustralia, Snowy Hydro (with retail brands Red Energy and Lumo Energy), Engie (Simply Energy), Alinta Energy, Hydro Tasmania (Momentum), Meridian Energy (Powershop) and Pacific Hydro (Tango).

Chart 5: Electricity retail market share (small customers)



Note: Includes residential and small business customers. All data at December 2020, except Victoria (electricity and gas, June 2020) and Tasmania (gas, June 2020).
 Source: AER, *Retail markets quarterly, Q2 2020–21*, April 2021; ESC, *Victorian energy market report 2019–20*, December 2020; Office of the Tasmanian Economic Regulator, *Energy in Tasmania report 2019–20*, December 2020.

Table 15: East Coast Gas Consumption – By State and Sector (2021) PJs and %

State	Gas Powered Generation	Industrial	Residential & Commercial	Total
Queensland	36.6 (24%)	108.6 (72%)	5.9 (4%)	151.1 (27%)
NSW	9.1 (8%)	54.2 (48%)	50.3 (44%)	113.6 (21%)
Victoria	10.6 (5%)	65.6 (32%)	128.4 (63%)	204.6 (37%)
SA	41.7 (55%)	23.9 (31%)	10.9 (14%)	76.5 (14%)
Tasmania	0.2 (3%)	6.1 (86%)	0.8 (11%)	7.1 (1%)
Total	98.2 (18%)	258.4 (47%)	196.3 (36%)	552.9

Source: AEMO 2022 GSOO

Industrial loads for gas include industries, such as aluminium, and chemical production, such as fertiliser and manufacturing.

Table 16: Australia’s annual energy generation by fuel type (2020-21)

Coal	Gas	Wind	Hydro	Grid-scale Solar	Distributed PV	Battery Storage Systems	Biomass
64.67%	6.57%	10.45%	7.21%	3.85%	7.09%	0.05%	0.09%
131.27 TWh	13.33 TWh	21.20 TWh	14.64 TWh	7.81 TWh	14.39 TWh	0.11 TWh	0.18 TWh

The Australian Domestic Gas Security Mechanism (ADGSM)

The ADGSM was established in 2017 as a framework to restrict LNG exports where there is a reasonable prospect of a supply shortfall in the east coast domestic gas market. The assessment period for the ADGSM is currently annual, with reforms announced this year to shift this to a quarterly assessment.

The regulatory impact of the ADGSM was considered in the Impact Assessment on the implementation of the scheme in June 2022 (see A7 in AA22/0197), as well as at the announcement of further reforms (including shift to quarterly assessment) in October 2022.

During the shortfall assessment period, the Minister for Resources determines whether a shortfall is likely. If a shortfall is likely, the Minister will decide how much gas needs to be redirected to the domestic market to prevent the shortfall. Concurrently, the Minister will determine how much gas each LNG producer needs to contribute to this amount.

Under the current version of the ADGSM, if an LNG producer takes more gas from the domestic market than they supply, that producer is considered to be in net deficit. An LNG producer in net deficit will bear more of the responsibility to redirect gas to the domestic market. As such, if there is only one LNG producer in net deficit, that producer is solely responsible for preventing the shortfall. If no LNG producers are in net deficit, none of them will be obligated to offer gas to the domestic market. In this situation, the shortfall will not be addressed.

The Minister for Resources will issue a public determination notifying the Minister’s decision to activate the ADGSM and invoke export controls. This will grant LNG producers export permissions, which may be attached with conditions. Export permissions will allow an LNG producer to either export an unlimited amount of gas, or to export only up to a certain amount (for those in net deficit).

The Minister can revoke a determination of a shortfall year at any time. Within 30 days after the determination is made (the Minister has discretion to shorten this period), LNG producers can provide feedback to the Minister on their export permissions.

The export permissions come into effect at the beginning of the shortfall year (at the beginning of 2023). They will last for the duration of the shortfall year. Once an export permission is set, it cannot be reduced unless its conditions have been breached.

Appendix B: Regulatory Burden Costings

Of the options considered in this Impact Analysis, the following three options are expected to create regulatory burdens for businesses:

- Option A1: Legislate a new framework for the making of energy market codes within the CCA, and prescribe a mandatory Code of Conduct for wholesale gas markets
- Option A2 – Prescribe a mandatory Code of Conduct for wholesale gas markets under the existing industry codes framework (Part IVB of the CCA)
- Option A4 – Temporary 12-month gas price cap

This technical appendix provides further information detailing how regulatory burden costs for each of these options were calculated, including the assumptions made in estimating these costs.

Option A1: Legislate a new framework for the making of energy market codes within the CCA, and prescribe a mandatory Code of Conduct for wholesale gas markets

Table 17: Summary of regulatory burden calculations:

Cost category	Costs over ten years	Average costs per year
Adjusting internal processes	\$1,164,589	\$116,459
Legal compliance advice	\$2,550,000	\$255,000
Arbitration	\$4,320,000	\$432,000
Total	\$8,034,589	\$803,459

Number of businesses impacted

This impact analysis assumes that businesses selling gas in the wholesale gas market will be affected by the mandatory Code of Conduct and face regulatory costs. This includes gas producers operating in the east coast market and other businesses selling into the wholesale contract market such as gas retailers. Based on information in a recent ACCC report¹², we assume there are 21 gas producers operating in the east coast gas market. We also assume there are 44 gas retailers operating in the east coast gas market based on the AER's public register of authorised gas retailers.¹³ This adds up to 65 businesses affected by the mandatory Code of Conduct.

¹² ACCC 2021, *Review of upstream competition and the timeliness of supply: Issues Paper*, p. 6.

¹³ https://www.aer.gov.au/retail-markets/authorisations/public-register-of-authorised-retailers-authorisation-applications?f%5B0%5D=field_accc_aer_sector%3A5&f%5B1%5D=field_accc_aer_status%3A7

Hourly wage rate

We use the Office of Impact Analysis’ default hourly wage rate for businesses of \$79.63 per hour.

Hourly cost of legal advice

We assume a standard blended junior and senior hourly cost of legal advice of \$500 per hour.

Arbitration fees

We assume that the average amount in dispute in arbitration proceedings is \$6,000,000. This corresponds to \$20,000 in arbitrator fees per arbitration.¹⁴

Staff time to adjust internal processes

There is likely to be some variability in the amount of time different businesses require to adjust internal processes to the mandatory code. We assume this could take between 50 and 400 hours and so we take an average of 225 hours for the calculations.

Hours of legal compliance advice

Businesses will require legal advice to assist with complying with the mandatory code. Given the three east coast LNG exporters hold a significant market share in the east coast gas market, we assume that they are likely to invest more in legal advice than other businesses. Therefore, we assume these three businesses will pay for 150 hours of legal compliance advice and the other 62 businesses will pay for 75 hours of legal compliance advice.

Hours of legal advice for arbitration

It is assumed that each business involved in arbitration proceedings will pay for 250 hours of legal services.

Number of arbitration proceedings

It is assumed that there will only be one arbitration required (2 businesses affected) in the first year under the code because a price cap would limit reasons for arbitration being required. This would increase to 4 arbitrations (8 businesses affected) in the second year once the price cap expires before tapering down to 3 arbitrations in the third year (6 businesses affected), 2 arbitrations in the fourth year (4 businesses affected) and 1 arbitration each year for years 5-10 (2 businesses affected) as the possibility of arbitration improves negotiations between businesses.

Calculations

Table 18: Costs of adjusting internal processes (one-off cost in year 1):

Costs of adjusting internal processes
= *Number of businesses impacted * Adjustment time * Hourly wage rate*

Number of businesses impacted	Adjustment time	Hourly wage rate	Cost
65	225	\$79.63	\$1,164,589

¹⁴ Australian Centre for International Commercial Arbitration, *Schedule of Fees*.

Table 19: Costs of legal compliance advice (one-off cost in year 1):

Costs of legal compliance advice
 = Number of businesses impacted * Hours of legal advice per business
 * Hourly cost of legal advice

Number of businesses impacted	Hours of legal advice per business	Hourly costs of legal advice	Cost
3	150	\$500	\$225,000
62	75	\$500	\$2,325,000
Total			\$2,550,000

Table 20: Arbitration costs:

Costs per arbitration
 = Number of businesses involved in arbitration
 * Hours of legal advice per business * Hourly cost of legal advice
 + Arbitrator fees

Year	Number of businesses impacted	Hours of legal advice per business	Hourly costs of legal advice	Arbitrator fees	Cost
1	2	250	\$500	\$20,000	\$270,000
2	8	250	\$500	\$80,000	\$1,080,000
3	6	250	\$500	\$60,000	\$810,000
4	4	250	\$500	\$40,000	\$540,000
5	2	250	\$500	\$20,000	\$270,000
6	2	250	\$500	\$20,000	\$270,000
7	2	250	\$500	\$20,000	\$270,000
8	2	250	\$500	\$20,000	\$270,000
9	2	250	\$500	\$20,000	\$270,000
10	2	250	\$500	\$20,000	\$270,000
Total					\$4,320,000

Option A2 – Prescribe a mandatory Code of Conduct for wholesale gas markets under the existing industry codes framework (Part IVB of the CCA)

Table 21: Summary of regulatory burden calculations:

The regulatory burden calculations for Option A2 are the same as Option A1, except Option A2 does not include any arbitration costs.

Cost category	Costs over ten years	Average costs per year
Adjusting internal processes	\$1,164,589	\$116,459
Legal compliance advice	\$2,550,000	\$255,000
Total	\$3,714,589	\$371,459

Option A4 – Temporary 12-month gas price cap

Table 22: Summary of regulatory burden calculations:

Cost category	Costs over ten years	Average costs per year
Adjusting offers to market	\$776,393	\$77,639
Legal compliance advice	\$812,500	\$81,250
Total	\$1,588,893	\$158,889

Hours to adjusted offers to market

It is assumed that businesses require 100 hours of labour costs to adjust their offers to the market in response to the price cap and 50 hours to adjust their offers upon expiry of the price cap.

Hours of legal advice required

It is assumed that businesses will pay for 25 hours of legal advice to assist with complying with the price cap.

Calculations

Table 23: Adjusting offers to market:

Adjustment costs

$$= \text{Numbers of businesses impacted} * \text{Adjustment time} * \text{Hourly wage rate}$$

Year	Number of businesses impacted	Adjustment time	Hourly wage rate	Cost
1	65	100	\$79.63	\$517,595
2	65	50	\$79.63	\$258,798

Year	Number of businesses impacted	Adjustment time	Hourly wage rate	Cost
Total				\$776,393

Table 24: Costs of legal compliance advice (one-off cost in year 1):

Costs of legal compliance advice

*= Number of businesses impacted * Hours of legal advice per business
 * Hourly cost of legal advice*

Number of businesses impacted	Hours of legal advice per business	Hourly costs of legal advice	Cost
65	25	\$500	\$812,500