ACIL ALLEN

14 December 2022

Report to Australian Petroleum Production & Exploration Association (APPEA)

Impact of price caps in the east coast gas market

Final report

About ACIL Allen

ACIL Allen is a leading independent economics, policy and strategy advisory firm, dedicated to helping clients solve complex issues.

Our purpose is to help clients make informed decisions about complex economic and public policy issues.

Our vision is to be Australia's most trusted economics, policy and strategy advisory firm. We are committed and passionate about providing rigorous independent advice that contributes to a better world.

Suggested citation for this report: *ACIL Allen (2022) The impact of price caps in the East Coast gas market*

Reliance and disclaimer The Treasurer and Ministers for Climate Change and Energy and Industry and Science announced actions to limit the impacts of forecast gas price increases on 9 December 2022. The action included the introduction of a temporary price cap on new domestic wholesale gas sales for a period of 12 months. The cap will be set at $12/GJ through an emergency price order and will apply to uncontracted gas offered on the wholesale market from currently operating fields capable of supplying gas during the period that the order is in place. professional analysis and advice in this report has been prepared by ACIL Allen for the exclusive use of the party or parties to whom it is addressed (the addressee) and for the purposes specified in it. This report is supplied in good faith and reflects the knowledge, expertise and experience of the consultants involved. The report must not be published, quoted or disseminated to any other party without ACIL Allen's prior written consent. ACIL Allen accepts no responsibility whatsoever for any loss occasioned by any person acting or refraining from action as a result of reliance on the report, other than the addressee.

In conducting the analysis in this report ACIL Allen has endeavoured to use what it considers is the best information available at the date of publication, including information supplied by the addressee. ACIL Allen has relied upon the information provided by the addressee and has not sought to verify the accuracy of the information supplied. If the information is subsequently determined to be false, inaccurate or incomplete then it is possible that our observations and conclusions as expressed in this report may change. The passage of time, manifestation of latent conditions or impacts of future events may require further examination of the project and subsequent data analysis, and re-evaluation of the data, findings, observations and conclusions expressed in this report. Unless stated otherwise, ACIL Allen does not warrant the accuracy of any forecast or projection in the report. Although ACIL Allen exercises reasonable care when making forecasts or projections, factors in the process, such as future market behaviour, are inherently uncertain and cannot be forecast or projected reliably.

This report does not constitute a personal recommendation of ACIL Allen or take into account the particular investment objectives, financial situations, or needs of the addressee in relation to any transaction that the addressee is contemplating. Investors should consider whether the content of this report is suitable for their particular circumstances and, if appropriate, seek their own professional advice and carry out any further necessary investigations before deciding whether or not to proceed with a transaction. ACIL Allen shall not be liable in respect of any claim arising out of the failure of a client investment to perform to the advantage of the client or to the advantage of the client to the degree suggested or assumed in any advice or forecast given by ACIL Allen.

ACIL Allen acknowledges Aboriginal and Torres Strait Islander peoples as the Traditional Custodians of the land and its waters. We pay our respects to Elders, past and present, and to the youth, for the future. We extend this to all Aboriginal and Torres Strait Islander peoples reading this report.

Goomup, by Jarni McGuire

Contents

Contents

Executive summary

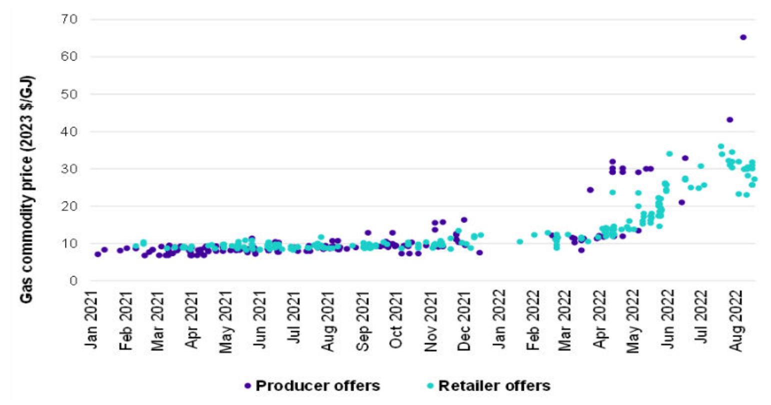
ACIL Allen has been engaged by the Australian Petroleum Production & Exploration Association (APPEA) to prepare a report that analyses the potential impact of gas price caps on the East Coast Gas Market (ECGM). ACIL Allen has drawn on its proprietary market models of the ECGM to underpin the analysis. This analysis focuses on the long term impacts of a price cap due to supply investment being delayed or cancelled.

Recent gas price trends

Spot gas prices increased dramatically in 2022 across the east coast gas market. The increase began in February and surged in April as many factors combined to see spot market prices spike to levels that eventually resulted in spot markets entering administered pricing arrangements with spot prices capped at $40/GJ for a period. The underlying drivers of the recent surge in spot prices have been the Russia-Ukraine war affecting international LNG prices, high gas demand in southern states from cool weather conditions, outages at coal fired power stations and restricted availability of coal for power generation.

The Australian Competition and Consumer Commission (ACCC), as part of its ongoing Inquiry into contracted gas prices in the Eastern Australian gas market, has been monitoring offers being made by gas producers and retailers for new Gas Supply Agreements (GSAs) and agreed prices executed in GSAs as part of its Gas Inquiry 2017 to 2025.[1] Figure ES 1 below shows the ACCC data on gas commodity prices included in offers made by producers and retailers for supply in 2023.

Figure ES 1 Gas commodity prices (2023 $/GJ) offered in the east coast gas market for 2023 supply



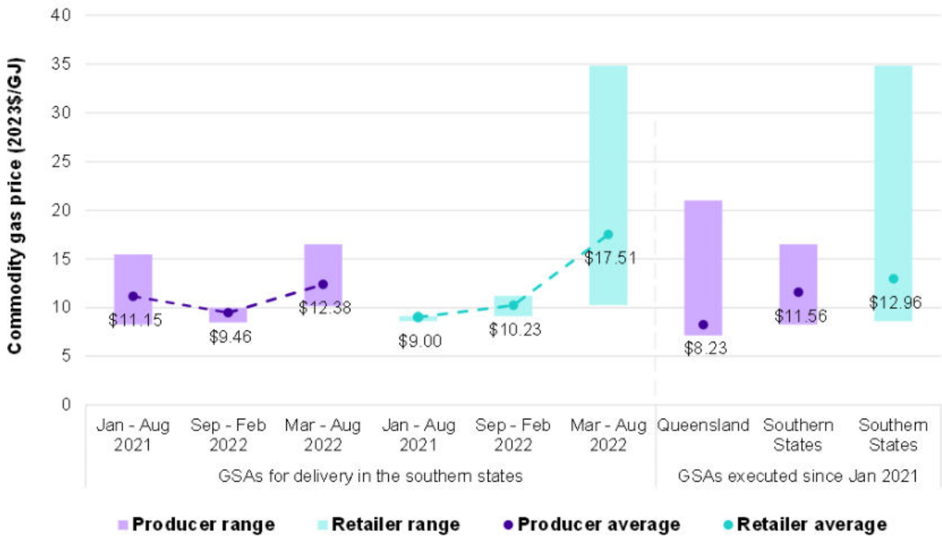
Source: ACCC

[1] 14 November 2022 release at January 2023 interim report - Preliminary gas pricing | ACCC

The figure shows that from April 2022, there has been a noticeable upward trend in prices offered by producers and retailers to levels varying between $20-40/GJ in August 2022. Additionally, since the start of 2022, the range of prices offered by producers has widened, with the range of offers now much more variable compared with offers generally across 2021.

However, arguably the more important reflection of price movements is in Figure ES 2. This chart presents the quantity weighted average price paid under GSAs (reflecting prices that have been agreed to under supply contracts). It shows that prices agreed under recently struck GSAs for supply in 2023 have also increased, particularly for southern state customers. Although, this data suggests the price increases have been modest, particularly for supply provided by producers.

Figure ES 2 Gas commodity prices (2023 $/GJ) payable under GSAs in the east coast gas market for 2023 supply



Source: ACCC

The prospect of gas price caps

The Treasurer and Ministers for Climate Change and Energy and Industry and Science announced actions to limit the impacts of forecast gas price increases on 9 December 2022. The action included the introduction of a temporary price cap on new domestic wholesale gas sales for a period of 12 months. The cap will be set at $12/GJ through an emergency price order and will apply to uncontracted gas offered on the wholesale market from currently operating fields capable of supplying gas during the period that the order is in place.

Gas from undeveloped fields and gas sold through the Short Term Trading Markets and the Victorian Declared Wholesale Gas Market will be exempted from the cap. Any diversion of gas to the spot markets that the ACCC determines is intended to circumvent the price cap will be subject to potential enforcement action under the legislation's anti-avoidance provisions.

Agreements reached through the Gas Supply Hub (Wallumbilla and Moomba) will be within scope of the price cap.

New sources of supply from undeveloped fields will be exempted from the cap, and instead be covered by a reasonable pricing provision.

A mandatory code of conduct will apply to contracts between gas producers and their customers in the east coast gas market. The code will include a provision for reasonable pricing. This will provide a basis for producers and buyers to negotiate domestic wholesale gas contracts based on guidance on reasonable pricing from the ACCC, which will reflect the long-run costs of domestic production and an appropriate return on capital. If producers and buyers are unable to agree, they may seek a binding arbitration determination.

The key risk of the price cap that this report is analysing is the potential impacts on the ECGM if supply investments are delayed or cancelled. This could apply to both marginal production from existing fields as well as production from new fields of supply from imported LNG. Price caps can create uncertainty which deters investors from committing to an investment. Considering the position, the gas market is already in, and the uncertainty around the role gas will play in the future, introducing price caps poses a real risk for any new gas supply investment, despite the reasonable pricing provision for new sources of supply. It is not clear for example, how the reasonable pricing provision would apply to importers of LNG. Price caps are likely to increase uncertainty and further reduce the investment window to a point where it does not make commercial sense to invest.

This is not a signal the market needs when investment in supply is so crucial over the medium and long term as the energy market transitions to a net zero economy.

Furthermore, although the price cap has been announced for a temporary period of 12 months, the ability for this to be extended is provided in the regulation. This aspect may ultimately result in new gas supply projects being delayed or cancelled, because investors will be uncertain as to what regulatory environment they will face.

Methodology

ACIL Allen's approach to this analysis focuses on demonstrating the impacts of capping gas prices using our market model. Our analysis aims to demonstrate what the impacts could be from a short-, medium- and long-term perspective. However, our focus is predominately on the longer term impacts due to delayed or cancelled investment in new gas supplies.

ACIL Allen's gas market model of the east coast gas market, *GasMark*, has been used to analyse the impacts of price cap scenarios against a base case. GasMark is a market optimisation model that solves for supply, demand and transport costs in the east coast gas market.

The analysis compares scenarios with delayed or cancelled investment against a base case scenario. The base case scenario represents the situation where some major anticipated and committed projects proceed at current expected commencement dates. The degree to which a price cap affects future investments is somewhat subjective and inherently uncertain and therefore the scenarios cover a range of outcomes from relatively minor delays through to significantly reduced upstream investments.

The scenarios which ACIL Allen have modelled in this report are the following:

- **Base case (no price cap):** ACIL Allen's current base view of how the market could play out
  - Narrabri enters the market in 2026
  - Port Kembla LNG imports by 2024
- **Scenario 1**: No LNG import terminals are commissioned, the Narrabri project by Santos is delayed (by 2 years) and CSG flows from Queensland to southern states are weaker
- **Scenario 2**: No LNG import terminals (more specifically, no Port Kembla terminal), delayed Narrabri gas project (2028) and weaker Victorian offshore investment (some longer term small to medium sized projects are shelved)
- **Scenario 3**: No Narrabri, delayed Port Kembla and weaker flows from the Queensland LNG joint ventures to southern states
- **Scenario 4**: No Narrabri, No Port Kembla, weaker supply in broader east coast market (offshore Victoria and Queensland CSG).

These scenarios were chosen as examples and the specific projects included do not represent projects that might face difficulties under price caps. It serves to illustrate what the impacts could be if these types of projects were at risk.

Gas price impacts

Short term impacts

Prices for new wholesale supply in the short term will obviously be subject to the price cap. The overall impact on the east coast gas market if price caps were imposed will primarily come down to how many gas users need to recontract through this period. Users that have secured gas supply agreements before winter 2022 will continue to pay the price set out in those contracts.

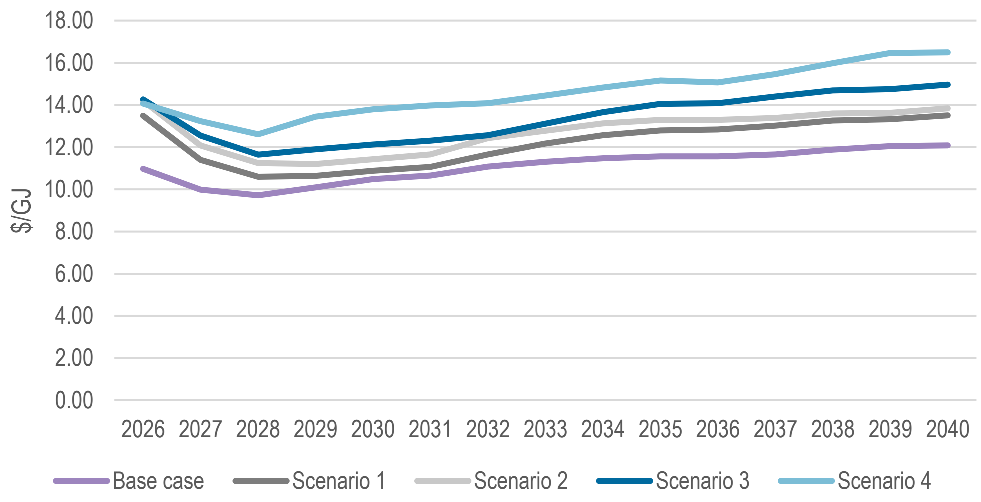
Gas users that need to recontract gas during the 12 month period of the cap will pay no more than the price cap. After the 12 month period concludes, new contracts will be subject to the provisions of the reasonable pricing provision. While the consultation paper sets out the general intent of the reasonable pricing provision, the details are yet to be finalised. Its impact on investment of undeveloped gas reserves therefore remains uncertain.

Longer term price impacts

ACIL Allen projected what might happen to wholesale gas prices for new supply in scenarios where certain supply investments are delayed or cancelled. The price output was then compared with the long-term projection in the base case scenario. The projections start from 2026 (this modelling was undertaken prior to the announcement on 9 December and assumes a cap might exist for a period of three years) and end in 2040. The modelling did not take into account the reasonable pricing provision and its possible impact on future supply from undeveloped reserves. These impacts are uncertain at this stage.

Figure ES 3 below presents our projections under the base case scenario and the three scenarios with different assumptions on future supply investment. Our modelling suggests that a price cap is likely to place upward pressure on wholesale gas prices in the east coast gas market in the longer-term due to the impact on supply investment.

Figure ES 3 Projected Victorian wholesale gas prices, 2026 to 2040



Source: ACIL Allen

Wholesale prices for new supply are projected to be higher than the base case over the period from 2026 to 2040. For scenarios 1 and 2, the largest differences are in the early years of the projection period. This is because during these years (2026 and 2027 in particular) the market is still expected to be tight in terms of the demand/supply balance. Supply sources such as an LNG import terminal, Narrabri, and other supply (Queensland supply and Victorian offshore) will be important in helping the market meet demand in this period.

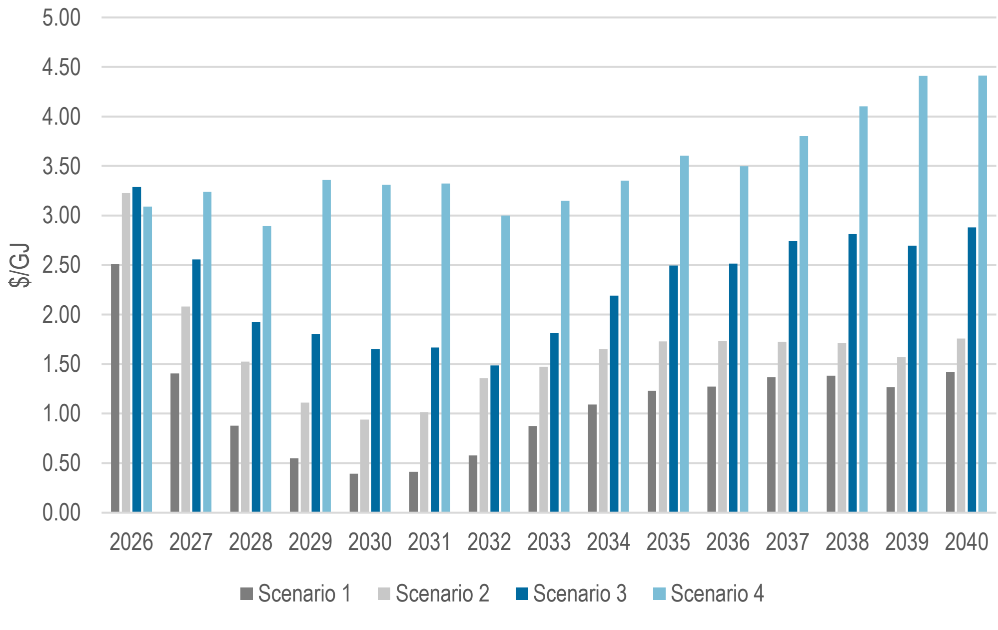
The difference in 2026 for these cases is between $2.50 and $3.00/GJ (representing a 25-30 per cent increase in wholesale costs to consumers).

For scenarios 3 and 4, much lower gas investment across the entire projection period means prices will be much higher from 2026 to 2040. Prices by 2040 will be around $3.00/GJ higher in scenario 3 and $4.50/GJ higher in scenario 4 than in the base case (or 25 per cent to 40 per cent higher).

These scenarios then suggest a real risk for consumers if the price caps delay or cancel a broader range of supply investments across the ECGM. Prices projected in these scenarios will be readily over $12/GJ from the mid-to-late 2020s. if price caps were not imposed and the market was left to invest in supply without uncertainty, the base case projects prices to return to levels around $10-12/GJ.

Figure ES 4 shows how much higher wholesale prices for new supply will be in the capped price scenarios against the base case. The key message here is that the entire market potentially faces much higher prices in the long-term as a consequence of a policy that may benefit only a portion of the market for a short period.

Figure ES 4 Difference in projected wholesale gas prices in Victoria compared with base case, by scenario



Source: ACIL Allen

Impacts on supply deliverability

Another key impact from enacting price caps is the market's ability to meet peak day demand in the winter period. As the ACCC and AEMO have mentioned consistently in recent years, meeting peak demand is becoming increasingly challenging. Additional investment in supply and supply infrastructure capacity will be important in addressing this challenge.

ACIL Allen ran its model on a daily basis to compare what the impact could be if certain investment was not available during the peak period running from 2023 to 2027 in Victoria. This was compared with the peak supply capability of the system in Victoria under our base case.

Table ES 1 below shows the peak day supply capacity from our base case compared with scenario 1. This aims to help demonstrate that without important sources of supply, such as Port Kembla LNG, the market's ability to meet peak day could be compromised. For example, in 2026 peak supply capacity in the base case would be around 1,288 TJ/day. However, in Scenario 1 the projected supply capacity in Victoria could be 250 TJ/day less. This is because some additional supply investment is not in the market by 2026. For the other scenarios (scenarios 2 to 4), the peak day supply problem will become more challenging with further investment in new supply being delayed/cancelled.

Table ES 1 Projected peak day supply capacity in Victoria (TJ/day)

	2023	2024	2025	2026	2027
Base case	1,186	1,290	1,302	1,288	1,264
Scenario 1	1,186	1,221	1,165	1,038	1,101
Difference	-	- 68	- 137	- 250	-163

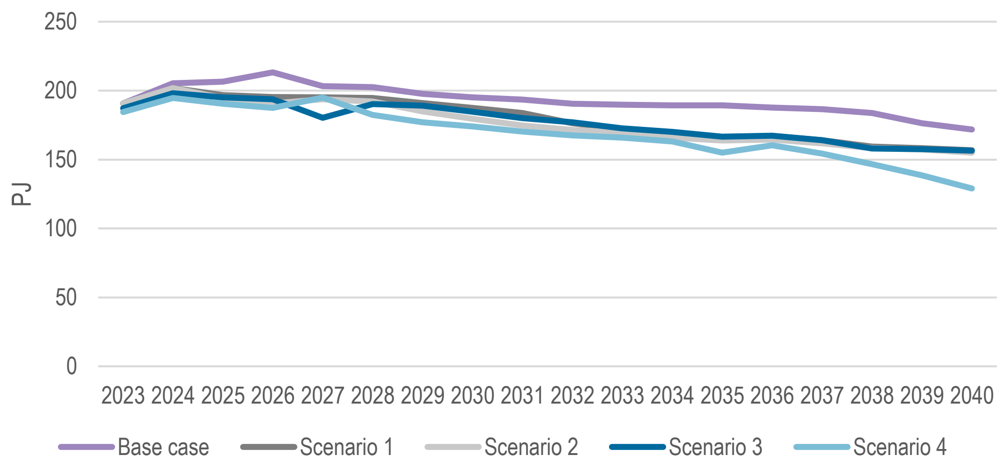
Source: ACIL Allen

This analysis demonstrates that if a price cap were to delay investment, the ability of the market to meet a peak demand day could be compromised. The results illustrate that without expected supply developments entering the market, meeting peak demand could be more challenging. This is turn might lead to calls for further market intervention to augment gas supplies to meet peak requirements. If new supply cannot be offered into the market, demand will need to be curtailed on these peak demand days.

Long term consumption impacts

Longer term impacts on consumption relate to projections for longer term gas prices. Higher gas prices in the future might mean gas users switch away from natural gas if prices are higher than what they consider bearable. This could be through either switching to alternative energy options or shutting down. Figure ES 5 below demonstrates what the impact on the Victorian market could be from supply investments that are delayed or cancelled.

Figure ES 5 Long term projected Victorian market consumption



Source: ACIL Allen

The results show lower long-term consumption because of the higher projected prices after the caps are removed in 2026. Projected consumption impacts are larger towards the back end of the projection period. As prices move higher, they approach or exceed what some users might be willing to pay for gas. They therefore change their behaviour by reducing the volume of gas they consume, switch out of natural gas all together, or businesses close. The consumption 'lost' is mainly from residential/commercial users and the industrial sector.

Key findings

There are several issues then when considering capping gas prices:

- Lower capped prices can **encourage additional consumption** that can potentially put significant strain on gas supplies during peak periods (similar to what happened in winter 2022)
  - This strain is likely to be even worse than winter 2022 because capped prices may encourage additional consumption without any supply side response (less incentive for producers to offer additional supply to the market even despite the reasonable pricing provision for new supply)
- The prospect of temporary price controls may have adverse impacts on supplier behaviour and **create incentives to leave gas in the ground until controls are lifted, potentially deferring production and/or investment**. This could defer injections into storage and leave storages underfilled ahead of future peak periods (vital to meet peak demand)
- This would see gas prices rise substantially over the long term if investments are delayed or cancelled. **Short term relief for some consumers can unfortunately lead to longer term impacts for all gas consumers**
  - Our analysis suggests wholesale prices could increase anywhere from $1.50/GJ to $4.50/GJ (or around 10 per cent to 40 per cent higher) in the long term depending on what investments are delayed/cancelled
  - If price caps were not imposed and investment was not delayed/cancelled, wholesale prices are expected to return to levels between $10-12/GJ over the long term as new supply comes online
  - Imposing price caps which delay or cancel investment means prices are projected to stay higher over the long term, with a return to long term prices averaging between $10-12/GJ a much harder goal to achieve
- Peak supply deliverability is likely to be affected if investments are delayed or cancelled. This is particularly evident in the short to medium term with the market remaining tight on supply. Our modelling suggests **meeting peak day demand in Victoria could be significantly more difficult if supply is delayed**
  - Of particular note is the potential for the price caps to defer or cancel potential LNG import terminals that are potential suppliers of gas in the medium term as existing gas production in southern basins declines.

Introduction 1

1.1 Introduction

ACIL Allen has been engaged by the Australian Petroleum Production & Exploration Association (APPEA) to prepare a report that analyses the potential impact of gas price caps on the East Coast Gas Market (ECGM).

ACIL Allen has drawn on its proprietary market models of the ECGM to underpin the analysis. Our methodology in this report covers our approach to conducting the analysis and how the results should be interpreted.

1.2 Report structure

This report is structured as follows:

— Chapter 2 provides a brief background to the issue of affordability facing the east coast gas market.

— Chapter 3 sets out ACIL Allen's methodology for the analysis. Chapter 3 includes a description of the models, the developed scenarios, how key assumptions were confirmed for each scenario, and what the modelling outputs represent.

— Chapter 4 presents our analysis of impacts on the east coast gas market.

Background 2

2.1 Gas prices in Eastern Australia

For many years, gas prices in eastern Australia were low by international standards, and the prevalence of long-term contracts ensured price stability.

Historically, most of the gas in Australia was bought and sold through long-term bilateral contracts, typically for terms of up to 20 years. Transportation contracts were structured to match these long-term sales contracts and had similar durations. However, there has been a trend in recent years toward shorter-term contracts, with most gas supply and transportation contracts now less than five years, with many agreed for one or two years. A further trend has been for some larger users to rely on spot markets for supply increasingly.

The emergence of the Gladstone LNG projects has had a transformative effect on gas prices in the ECGM . In particular, there has been a significant shift in the basis on which gas sold under long-term supply contracts is priced. In the past, the usual practice in the gas industry was to set a base contract price at a specified date. That base price was then subject to escalation periodically at a proportion (most often 100 per cent) of the Consumer Price Index or another relevant independent price index.

With the advent of LNG export projects offering a pathway to an international market in which contract prices have traditionally been linked to the price of oil, it has become commonplace for domestic gas supply contracts to be based on movements in international LNG prices. As the ECGM is now partially linked to the global LNG market, prevailing international prices directly affect domestic gas prices through an LNG netback calculation.

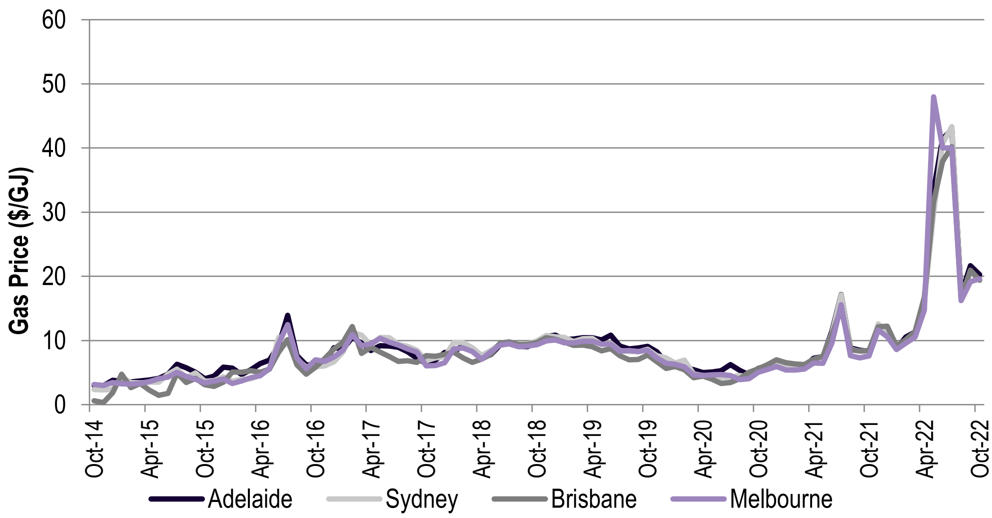
2.2 Recent price trends

2.2.1 Domestic spot prices

Spot gas prices have increased dramatically in 2022 across the east coast gas market. Prices began rising in February and surged in April as a combination of factors drove spot market prices to levels that eventually resulted in administered pricing arrangements being invoked. Under administered price arrangements, spot prices were capped at $40/GJ for a period (more than four times the average price in 2021) (see Figure 2.1).

The underlying drivers of the recent surge in gas prices have been the Russia-Ukraine war, high gas demand in southern states from cool weather conditions, outages at coal-fired power stations and restricted availability of coal for power generation.

Figure 2.1 STTM capital city prices



Source: ACIL Allen analysis of AEMO data

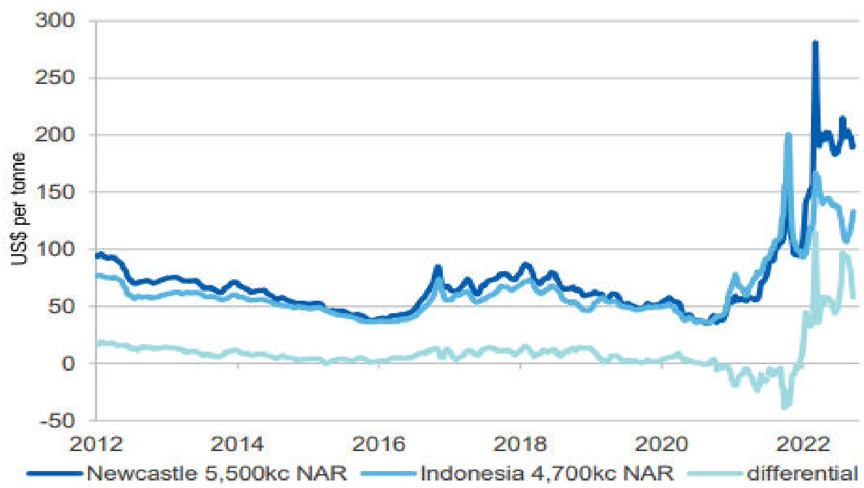
In particular, for the national electricity market (NEM), lower output from coal-fired power stations across eastern Australia led to increased demand for gas-fired electricity. This increased demand contributed to the sharp price rises in wholesale gas and electricity markets. Gas prices are expected to remain high in the short term due to the ongoing Russia-Ukraine war. The conflict continues to unsettle international energy markets and keep upward pressure on energy prices, particularly thermal coal, pipeline gas and LNG.

Some downward pressure on spot market prices has recently occurred in the ECGM, with the winter peak period passing and coal plant generation availability improving. However, if the international market remains highly disrupted for the foreseeable future, this will likely mean wholesale spot gas prices will stay elevated.

Coal spot prices

Importantly for eastern Australia's energy markets, coal prices also surged in 2022. Figure 2.2 shows how coal prices have trended.

Figure 2.2 Key benchmark spot coal prices



Source: Office of the Chief Economist: Resources and Energy Quarterly, September 2022

This rise in coal prices contributed to the increase in prices and, ultimately, the suspension of the NEM in June 2022. Higher coal prices, combined with low plant and coal mine availability, meant the various gas generators were called upon to generate electricity in much higher volumes. This higher demand for gas-fired generation exacerbated an already tight ECGM due to cold winter conditions.

Many factors driving higher coal prices are similar in nature to those driving higher gas prices internationally. Therefore, prices over the medium term could remain at much higher levels than has historically been the case.

Furthermore, the Office of the Chief Economist has mentioned that Australian coal remains in high demand in the wake of the Russian conflict with Ukraine, with Australia becoming the primary alternative supplier for higher coal grades[2]. This increased demand has led to additional price pressure among higher-grade coal products and is likely to see a larger share of Australian coal directed to Europe over time.

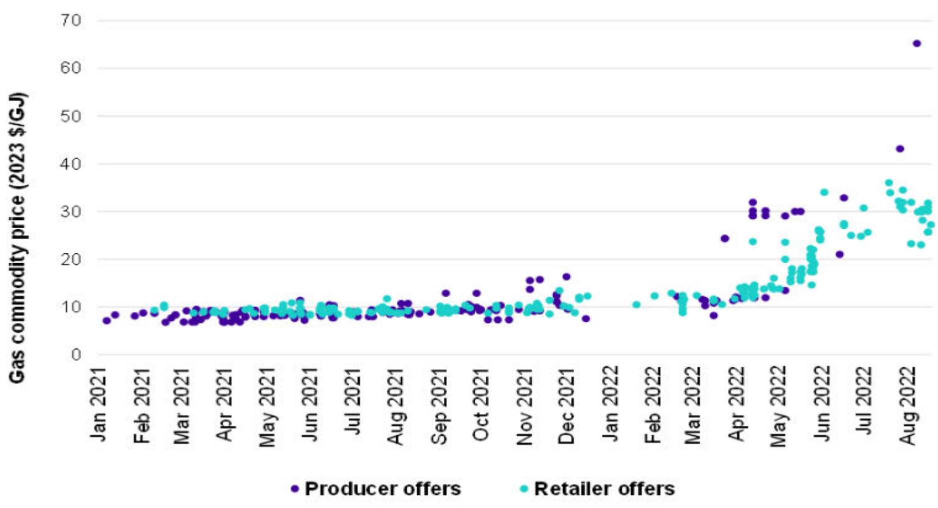
The key implication for the ECGM is that GPG may run at much higher capacity factors over the coming years and thus require higher volumes of gas for their operations.

2.2.2 Domestic contract prices

The short-term trading markets (STTMs) in Adelaide, Sydney and Brisbane, together with the Victorian spot gas market and the Wallumbilla Gas Trading Hub, now provide daily price information for the ECGM. These spot prices, however, tend to reflect short-term and seasonal variations in the supply-demand balance and bear little relationship to new long-term contract prices. Most gas in Eastern Australia is traded via bilateral contracts (Gas Supply Agreements) between gas users and gas producers/retailers.

The ACCC, as part of its ongoing Inquiry into gas prices in the ECGM, has been monitoring offers made by gas producers and retailers for new Gas Supply Agreements (GSAs) as part of its Gas Inquiry from 2017 to 2025[3]. This information was not available before the commencement of the Inquiry. Figure 2.3 below shows the ACCC data on gas commodity prices included in offers made by producers and retailers for supply in 2023.

Figure 2.3 Gas commodity prices (2023 $/GJ) offered in the east coast gas market for 2023 supply



Source: ACCC January 2023 Interim Report

[2] Office of the Chief Economist: Resources and Energy Quarterly September 2022 edition

[3] ACCC January 2023 Interim Report

The prices reported by the ACCC are wholesale gas commodity prices. They do not include separate charges for transporting gas to the user's location or other ancillary charges (although delivery charges may sometimes be bundled with commodity gas prices). The prices charged for transportation have been excluded from The ACCC's analysis to enable a more direct comparison between the prices paid by buyers in different locations and with differing transportation requirements.

Figure 2.3 shows that from April 2022, there has been a noticeable upward trend in prices offered by producers and retailers to levels varying between $20-40/GJ in August 2022. Additionally, since the start of 2022, the range of prices offered by producers has widened, with the range of offers now much more variable compared with offers generally across 2021.

In Figure 2.4 below, the chart compares the **quantity-weighted average price** paid under GSAs entered into by producers and retailers for delivery in the east coast gas market in 2023 across three periods:

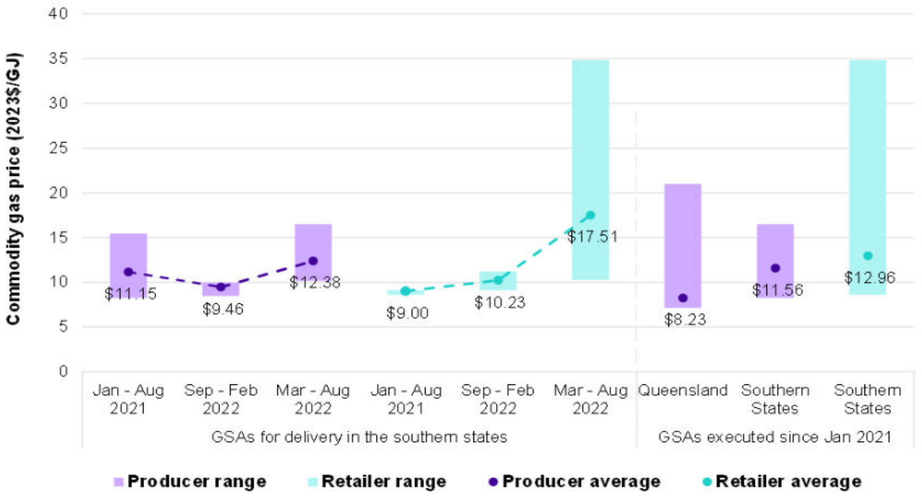
— January 2021 to August 2021

— September 2021 to February 2022

— March 2022 to August 2022.

This chart shows that the average quantity-weighted average price being paid under GSAs that have recently been struck is around $17-18/GJ for supply by retailers and about $12-13/GJ for supply by gas producers (for supply to southern states). Therefore, although some recent offers have been made at very high prices, the average weighted price being paid under GSAs is much lower than what many users are offered (particularly for supply provided by gas producers).

Figure 2.4 Gas commodity prices (2023 $/GJ) payable under GSAs in the east coast gas market for 2023 supply



Source: ACCC January 2023 Interim Report

2.3 Gas price caps

The Treasurer and Ministers for Climate Change and Energy and Industry and Science announced actions to limit the impacts of forecast gas price increases on 9 December 2022. The action included the introduction of a temporary price cap on new domestic wholesale gas sales for a period of 12 months. The cap will be set at $12/GJ through an emergency price order and will apply to uncontracted gas offered on the wholesale market from currently operating fields capable of supplying gas during the period that the order is in place.

Gas from undeveloped fields and gas sold through the Short Term Trading Markets and the Victorian Declared Wholesale Gas Market will be exempted from the cap. Any diversion of gas to the spot markets that the ACCC determines is intended to circumvent the price cap will be subject to potential enforcement action under the legislation's anti-avoidance provisions.

Agreements reached through the Gas Supply Hub (Wallumbilla and Moomba) will be within the scope of the price cap.

New sources of supply from undeveloped fields will be exempted from the cap and instead be covered by the reasonable pricing provision.

A mandatory code of conduct will apply to contracts between gas producers and their customers in the ECGM. The code will include a provision for reasonable pricing. This will provide a basis for producers and buyers to negotiate domestic wholesale gas contracts based on guidance on reasonable pricing from the ACCC, reflecting the long-run costs of domestic production and an appropriate return on capital. If producers and buyers cannot agree, they may seek a binding arbitration determination.

This report aims to demonstrate the short-, medium- and long-term impacts of introducing a price cap over three years.

2.3.1 Price caps impacts on investment

Although a price cap can alleviate short-term impacts of high prices, a price cap can have negative impacts long term. Price caps signal consumers to increase demand while simultaneously limiting supply (supply with costs above the price cap would be expected to withdraw from the market).

If the caps delay or cause gas market participants to postpone or cancel investments, gas prices could rise substantially, even after removing the price cap. This could affect marginal production from existing fields, production from new fields, or supply from imported LNG. As a result, meeting peak day demand could be more difficult, and the market could be less resilient and reliable overall. It also could have longer-term ramifications for the electricity market.

In this situation, the risk of a price cap is the uncertainty it can create. In such cases, gas producers may hold off committing to certain investments even despite the reasonable pricing provision that seeks to ensure new supply is incentivised. A complicating factor for the ECGM is the overall environment in which the gas market finds itself with increasing pressures to decarbonise and shift away from fossil fuels.

The main risk of imposing a price cap at this point is the delay it could cause to new investment. Suppose investors choose to reassess their investments when a price cap is lifted. In that case, the time frame to recover their investment is likely less than before (with the decarbonisation timetable limiting the potential for longer-term sales). Justifying investments, in this case, becomes more challenging.

Another risk for supply investors is the uncertainty around whether government intervention could become a more regular occurrence. Most investors require a reasonably predictable regulatory and policy environment and clear market signals to justify the investment. The imposition of price controls would create further regulatory uncertainty.

This report examines the impact on the market in the medium and long term if price controls are imposed for three years. The report is not arguing that investment delays would occur if price caps were imposed. However, at the current price for LNG in world markets, a cap of $11-13/GJ would cause investors on LNG import terminals to think twice about proceeding during the cap period. The report analyses the potential impacts if this were to occur due to price caps.

Methodology 3

3.1 Overall approach

ACIL Allen's approach to this analysis focuses on demonstrating the impacts of a gas price cap using our gas market model, *GasMark Global (GasMark)*. *GasMark* is described further below. A more detailed description of how the model works can be found in the material provided in Appendix A.

Our analysis seeks to demonstrate what the impacts could be from a short-, medium- and long-term perspective. We have concentrated on the long-term effects, specifically if any investment is delayed or cancelled due to a price cap.

In the short term, our understanding is that the price cap will not affect existing contracts. Therefore, consumers may not see a significant reduction in gas prices throughout the capped period. The main effect of the cap is likely to be a delay of one or two years in gas price increases as contracts are rolled over after the cap is removed.

However, any short-term benefit for consumers will ultimately be offset by longer-term impacts should the price cap intervention lead to delays or cancellation of future investments. Our long-term modelling focuses on these impacts.

ACIL Allen assessed these impacts by comparing scenarios with delayed or cancelled investment against a base case scenario which assumes no price cap is imposed on the market. The base case scenario represents where anticipated and committed projects proceed at expected dates.

3.1.1 Scenarios

The scenarios ACIL Allen modelled in this report are set out below. These scenarios were chosen as examples and the specific projects included do not necessarily represent projects that might face difficulties under price caps. It serves to illustrate what the impacts could be if these types of projects were at risk.

- **Base case:** ACIL Allen's current base view of how the market could play out
  - Narrabri enters the market in 2026
  - Port Kembla LNG imports by 2024
- **Scenario 1**: No LNG import terminals are commissioned, and the Narrabri project by Santos is delayed (by 2 years)
- **Scenario 2**: No LNG import terminals (more specifically, no Port Kembla terminal), delayed Narrabri gas project (2028) and weaker Victorian offshore investment (some longer-term small- to medium-sized projects are shelved) and CSG supply from Queensland
- **Scenario 3**: No Narrabri, delayed Port Kembla and much weaker flows from the Queensland LNG joint ventures to southern states

— **Scenario 4**: No Narrabri, No Port Kembla, weaker supply in the broader east coast market (offshore Victoria and Queensland CSG)

Scenarios 3 and 4 also assume that consumers' willingness to pay for natural gas is slightly higher than in scenarios 1 and 2 in the long term.

This modelling exercise informs the debate on what the impacts in the short term could be from capping prices. It also helps to assess what the effects could be in the longer term if price caps delay or cancel investment in future supply.

3.2 Gas market analysis - methodology

ACIL Allen's gas market model, *GasMark*, of the ECGM was used to analyse the impacts of price cap scenarios against a base case. *GasMark* is a market optimisation model that solves for supply, demand and transport costs in the ECGM. It produces outcomes reflecting the operation of a market that is working efficiently. More detail about of *GasMark* and its operation is provided in Appendix A.

An important element of *GasMark* is that it does not consider the impact of gas supply contracts on the market. Contracts can affect prices and deliveries in the short to medium term. While this needs to be considered when assessing the modelling results, *GasMark* indicates efficient market outcomes in the longer term, including supply and pricing. It is, therefore, useful when assessing how the market may fundamentally track in the medium to long term if different demand and supply scenarios eventuate.

The use of *GasMark* in this study was to understand the following impacts on the market of scenario:

— Impacts on gas prices

— Impacts on gas consumption

— Impacts on peak supply deliverability across a year (in the short to medium term)

The model can be run at annual, quarterly, monthly and daily resolution. For this report, we present annual price and consumption results for the period 2023 to 2040. We also present daily modelling results to illustrate any impacts on gas deliverability over a year, particularly for the peak winter period in the short to medium term.

3.3 Impact on wholesale gas prices

In the short term, some consumers may benefit from the price cap regime, although this is unclear. A price of $12/GJ will apply for new wholesale gas sales as per the announcement on 9 December 2022. However, this will depend on the contract situation in each case. Those on existing contracts may see little change in their gas prices until those contracts are rolled over. After the first year, new contracts will not be subject to the cap.

The longer-term impacts on gas prices are projected by running our gas market model. ACIL Allen compared price projections to 2040 for the above scenarios with the base case. We have illustrated the difference in prices using the results for the Victorian market price.

The price differences were modelled on an annual basis. Therefore, we compared the modelled projected price of wholesale gas in Victoria for each year, for all scenarios, against the base case projection.

3.4 Impact on gas consumption

Gas consumption impacts have also been modelled. The *GasMark* model has elasticities of demand built into the demand side, which allows modelling how price changes may affect consumption.

Projected consumption for each scenario was compared with the base case. Although consumption results are highly uncertain, they can still demonstrate the response of consumer markets to price rises.

3.5 Impacts on potential shortfalls

Another important aspect of evaluating the scenarios is assessing the impact on peak-day deliverability. Meeting peak day demand in the short to medium term is a pressing issue, constantly highlighted by AEMO and the ACCC in their respective reporting. ACIL Allen has modelled daily runs of the base case and scenarios to understand the impact on meeting peak day demand. For example, any delay in supply investment over the next few years could significantly impact how the market can manage a peak demand day.

We address this question in two stages:

1. Project peak day supply from ACIL Allen's base case scenario to determine the supply capacity the market can achieve over the period from 2023 to 2027 (excluding the supply that the Dandenong LNG plant can provide)
2. Compare this projection with the peak day supply achieved by the other scenarios over the same period (2023 to 2027).

The risk of introducing a price cap is that it may defer or delay investment crucial to meeting demand, resulting in supply shortfalls. Capping prices at $12/GJ also introduces the likelihood of increased demand during a peak demand period. These factors would exacerbate any supply-demand imbalance concerns.

This modelling aims to demonstrate how this may occur, and the potential impact should supply investment be materially affected. Naturally, there is an element of subjectivity to these impacts on investment, so the analysis should be considered illustrative rather than definitive. Despite this caveat, the modelling results demonstrate how the market's ability to meet consumer demand could be threatened if new supply is not brought to market on time.

Gas market analysis 4

This chapter presents the results of the gas market modelling. The chapter aims to demonstrate what the impacts on the ECGM might be if certain scenarios eventuate due to a gas price cap being introduced. As mentioned earlier, the analysis focuses on the longer-term effects of delayed or cancelled investment due to the planned capping of gas prices.

4.1 Gas price impacts

Gas price impacts can be split into two categories – impacts during the capped period and longer-term price impacts. ACIL Allen has concentrated on modelling the long-term impacts of a price cap. We have also briefly analysed the short-term impact during the capped period.

4.1.1 Price cap period

During the price cap period, the price of new wholesale gas will be subject to a $12/GJ cap over the 2023 calendar year. As per the announcement, this will not affect prices in the STTM markets or the DWGM. Additionally, new sources of supply from undeveloped fields will be exempted from the cap, and instead be covered by the reasonable pricing provision, which aims to ensure investment in new supply is still incentivised.

The impact on the ECGM if price caps are imposed will primarily come down to how many gas users re-contract through this period. Users who secured gas supply agreements before winter 2022 will likely have locked-in supply at prices below $10/GJ. Therefore, users that have already locked in contracts before the winter price rises, will be protected from higher prices that may occur in 2023.

Those gas users that have not locked in their supply for 2023, or have not made arrangements yet for their entire calendar year supply, may benefit from the price cap. If these users were only offered prices higher than $12/GJ, the announced cap should help them. How many users this affects is unknown. However, ACIL Allen expects this would affect only a small number of users.

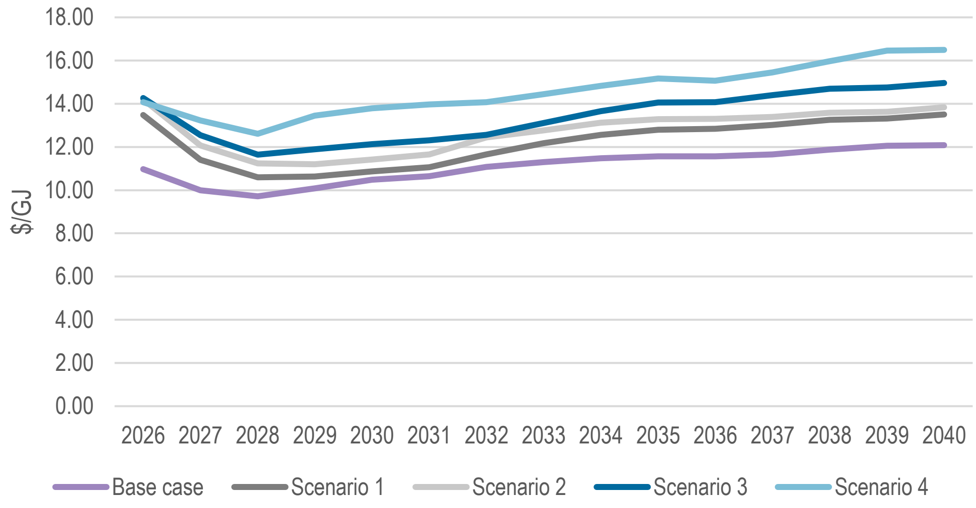
4.1.2 Longer term impacts

Longer-term price impacts are likely if the price cap policy results in the deferral or cancelling of new supply contracts. Using our market model of the ECGM, we modelled the impact on wholesale gas prices for new supply under certain price cap scenarios. The price projections for each price cap scenario were then compared to the price projections for the base case scenario. The projections start in 2026 and end in 2040.

ACIL Allen undertook the modelling before the 9 December 2022 announcement and assumed a price cap may have been implemented for up to three years (beginning in 2023). However, the modelling results still apply to the announced price cap regime. It is not necessarily the price at which gas is being capped or the period over which it is in place, but the policy creates uncertainty for gas suppliers. This includes both regulatory and investment environment uncertainty. Introducing price caps and providing provisions for these to be reviewed and extended creates sufficient uncertainty for gas suppliers to reconsider future gas supply investments.

Figure 4.1 below shows our projections under the base case scenario and the three scenarios with different assumptions on future supply investment.

Figure 4.1 Projected Victorian wholesale gas prices, 2026 to 2040

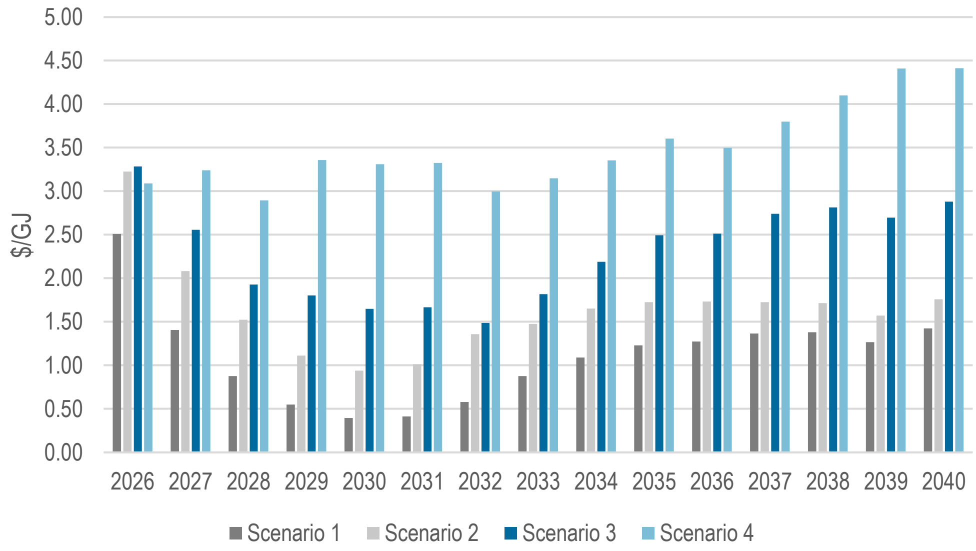


Source: ACIL Allen

Our modelling suggests that delays to significant supply investments or projects being shelved entirely will place upward pressure on wholesale gas prices in the east coast gas market in the longer term.

Figure 4.2 below illustrates the difference in projected wholesale gas prices for new supply in Victoria by scenario against base case projections.

Figure 4.2 Difference in projected wholesale gas prices in Victoria compared with base case, by scenario



Source: ACIL Allen

Wholesale prices for each scenario are projected to be higher than the base case over the entire period from 2026 to 2040. For scenarios 1 and 2, the most significant differences occur in the early years of the projection period. The delayed entry of the Narrabri project in 2028, significantly mitigates but does not fully offset higher prices compared with the base case. This demonstrates the importance of supply sources, such as an LNG import terminal, Narrabri, and other supply (Queensland supply and Victorian offshore), in helping the market meet demand in this period.

The difference in 2026 for these cases is between $2.50 and $3.00/GJ. If the delays continue into 2027, price impacts would be similar to 2026 (e.g., prices around $2.50-3.50/GJ higher). In the first two scenarios, some supply enters the market in 2027, which helps reduce the price impact.

For scenarios 3 and 4, much lower projected gas supply investment across the entire projection period means prices are projected to be much higher from 2026 through 2040. Prices by 2040 are projected to be around $3.00/GJ higher in scenario 3 and $4.50/GJ higher in scenario 4 compared to the base case (25 per cent to 40 per cent higher). These scenarios suggest a real risk for consumers if the price caps prevent a broader range of supply investments across the ECGM from progressing.

The primary risk of price caps is a delay in investment in supply. The price caps may provide temporary relief but simultaneously suppress price signals for investment, both during and after the period that they apply. Our modelling indicates that when price caps are lifted, prices are likely to be higher than in the base case, as less gas supply would be available to supply the market.

This is particularly important for the development and commissioning of LNG import terminals. The outlook for LNG prices over the 2022 to 2023 period is higher than the $12/GJ price cap assumed in our analysis. The price cap would likely deter investment in LNG imports for as long as it is in place and potentially beyond that because of uncertainty about future regulation and policy.

Price caps do not resolve the fundamental issues that are driving higher prices. The modelling shows that higher prices return after price caps are removed because the fundamental driver of higher prices has not been addressed.

Over the remainder of the projection period, the estimated difference hovers between around $1.50 to $4.50/GJ mark, depending on the scenario, representing around a 10 to 45 per cent increase in prices compared with the base case.

4.1.3 Retail price impacts

ACIL Allen estimated the high-level impacts and what they might mean for retail gas prices using Victoria as an example.

In the short term, there may be some relief for small gas users, such as residential gas customers. However, it is unknown what the magnitude of that benefit might be. In some cases, the benefit may be nil or very minimal in the first instance, as contracted supplies are likely to be covered by existing contracts. The price for residential customers may be influenced by price capping as contracts are rolled over in the first year. However, this effect will be discontinued when contracts are rolled after the first year (when price caps end).

Beyond the short term, the medium to long-term implications for residential gas bills could be significant if investments were delayed or shelved. For example, in scenarios 1 and 2, residential gas users in Melbourne could be paying around $70 per annum more from 2026 to 2040. The largest difference is in the early years, where residential bills could be $125 per annum higher. This is equivalent to an 8 per cent increase in the annual gas bill for a residential customer.

However, in scenario 4, residential users could be paying nearly $175 per annum more than the base case from 2026 to 2040. This is equivalent to a 10 per cent increase in the annual gas bill for a residential customer.

4.2 Impacts on supply deliverability

Another key impact from enacting price caps is the market's ability to meet peak day demand in the winter. As the ACCC and AEMO have noted consistently in recent years, meeting peak demand is increasingly challenging. Maximising supply and supply infrastructure capacity will be important in addressing this challenge.

Winter periods in the ECGM, particularly in Victoria, have a much higher gas demand than in the summer. This is primarily because of the much larger heating demand from gas users, including residential, commercial, and industrial users, and gas-fired power generators. Demand in winter is typically 3 to 4 times the summer demand. Additionally, Victoria can have days when demand is exceptionally high in winter. These days can be due to many factors including:

- Unusually cold winter days
- Supply outages during the peak winter period
- High demand for gas from gas-fired power generators during the peak winter period.

AEMO have planning processes that annually forecast what these peak demand days could look like. AEMO forecasts demand by using a 1 in 2 and 1 in 20 peak day demand probability. This information is included in AEMOs annual reports (the GSOO and the VGPR) to provide information to market participants.

Servicing peak demand requires production plants to increase short-term supply, storage facilities to inject higher volumes into the market, and markets to source supply from other sources with spare capacity during these periods. This is becoming more challenging for Victoria as peak-day deliverability declines from Bass Strait.

If a price cap delays investment, meeting peak demand during the winter could be difficult. Consequences could be shortfalls and loads having to be involuntarily curtailed if there is insufficient supply on those peak demand days.

ACIL Allen ran its model at a daily resolution to compare the impact if certain investments included in the base case, were unavailable during the peak period from 2023 to 2027 in Victoria. This was compared with the peak supply capability of the system in Victoria under the base case.

Table 4.1 below shows our base case's peak day supply capacity compared with scenario 1 (the least impacted scenario in terms of delayed/cancelled investment). This suggests that without sources of supply, such as Port Kembla LNG, the market's ability to meet peak day after 2025 could be significantly compromised. For example, in 2026, the peak supply capacity in the base case would be around 1,288 TJ/day. However, in Scenario 1, the projected supply capacity in Victoria could be 250 TJ/day less at its peak.

This does not mean the market will experience a shortfall because it will ultimately come down to the peak demand day in each of these years. However, if an unusually high peak demand day does eventuate, a scenario where some supply is unavailable to the market (e.g., scenario 1) could mean the market may find it difficult to meet this demand. Some demand would possibly have to be curtailed on a peak demand day.

Table 4.1 Projected peak day supply capacity in Victoria (TJ/day)

	2023	2024	2025	2026	2027
Base case	1,186	1,290	1,302	1,288	1,264
Scenario 1	1,186	1,221	1,165	1,038	1,101
Difference	-	-68	-137	-250	-163

Source: ACIL Allen

This analysis demonstrates that if a price cap were to delay investment, the ability of the market to meet a peak demand day could be compromised. Again, this modelling is not suggesting it would mean a shortfall. It illustrates that meeting peak demand is likely to be more challenging without expected supply developments entering the market. This might lead to further market intervention to augment gas supplies to meet peak requirements.

4.3 Impacts on long-term consumption

Longer-term impacts on consumption relate to projections for longer-term gas prices. Higher gas prices in the future might mean gas users switch from natural gas to other fuels or close operations, where costs are higher than the alternatives or higher than they are willing to pay.

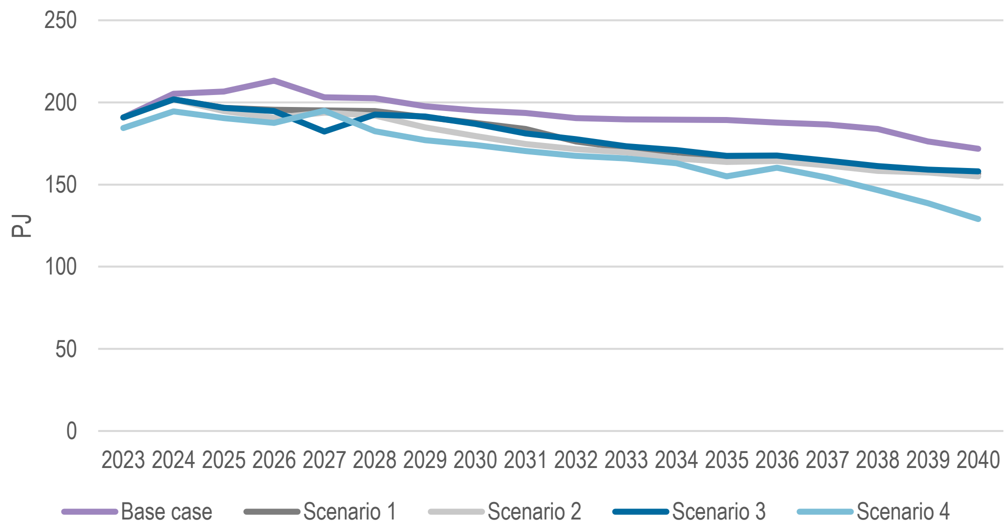
ACIL Allen's model has long-run price elasticities that attempt to consider the impact of price changes on consumption. In the modelling, higher gas prices could eventuate in the four scenarios ACIL Allen modelled due to investment delays and supply investments being shelved entirely.

These consumption impacts are uncertain, given ACIL Allen is estimating the maximum willingness to pay of various gas users. However, this approach is well grounded in economic literature, which tells us that, over time, price changes are likely to elicit a demand response.

Figure 4.3 below demonstrates the impact on the Victorian market from supply investments that are delayed or cancelled. The results show that consumption would be expected to be lower in the long term due to higher prices (see Figure 4.1). The consumption impacts are more significant towards the back end of the projection period as prices move higher and beyond what some users might be willing to pay for gas. Therefore, some consumers change their behaviour by reducing the volume of gas they consume, or they switch from natural gas to other fuels altogether.

The projected difference in consumption between the base case and scenarios 1 to 3 from the mid-2030s is around 15-20 PJ per annum. This is equivalent to several large industrial users exiting the market or a trend of a large number of small customers reducing their gas consumption. In scenario 4, consumption could fall by up to 40 PJ per annum towards the end of the projection period.

Figure 4.3 Long-term projected Victorian market consumption



Source: ACIL Allen

Our modelling suggests that the residential and commercial sectors account for most of the decline in consumption over the back end of the projection. This is mainly due to residential and commercial demand becoming more elastic over time as electricity becomes a more competitive alternative for household appliances.

4.4 Summary

Capping gas prices raises a number of concerns

- Capped prices can **encourage additional consumption** in the short term that can potentially put significant strain on gas supplies during peak periods (similar to what happened in winter 2022)
  - This strain in future years is likely to be worse than in winter 2022 because capped prices may encourage additional consumption while potentially inhibiting supply-side response (limited incentive for producers to offer additional supply to the market)
- The prospect of temporary price controls may adversely impact supplier behaviour and **create incentives to leave gas in the ground until controls are lifted, potentially deferring production and investment**. Price caps could also deter injections into storages and leave storages underfilled ahead of future peak periods (sufficient gas in storage is vital to meet peak demand)
- Deferral or cancellation of gas supply investment will likely lead to substantial gas price rises over the medium to long term. Therefore, **short-term relief for some (price caps) may, unfortunately, lead to longer-term impacts negative impacts for all gas consumers**:
  - Our analysis suggests wholesale prices could increase anywhere from $1.50/GJ to $4.50/GJ (or around 10 per cent to 40 per cent higher) in the long term, depending on which investments are delayed/cancelled.
- Peak supply deliverability will likely be affected if investments are delayed or cancelled. This is particularly evident in the short to medium term, with supply remaining tight in the market. Our modelling suggests **meeting peak day demand in Victoria could be significantly more difficult if supply investment is delayed**
  - Of particular note is the potential for the price caps to defer or cancel potential LNG import terminals that are potential suppliers of gas in the medium term as existing gas production in southern basins declines.

Appendices

Market models A

A.1 GasMark

GasMark Global (GMG) is a generic gas modelling platform developed by ACIL Allen. GMG has the flexibility to represent the unique characteristics of gas markets across the globe, including both pipeline gas and LNG. Its potential applications cover a broad scope — from global LNG trade, through to intra-country and regional market analysis. *GasMark Global Australia* (GMG Australia) is an Australian version of the model which focuses specifically on the Australian market (including both Eastern Australia and Western Australia), but which has the capacity to interface with international LNG markets.

The model can be specified to run at daily, monthly, quarterly or annual resolution over periods up to 30 years.

A.1.1 Settlement

At its core, *GasMark* is a partial spatial equilibrium model. The market is represented by a collection of spatially related nodal objects (supply sources, demand points, LNG liquefaction and receiving facilities), connected via a network of pipeline or LNG shipping elements (in a similar fashion to 'arcs' within a network model).

The equilibrium solution of the model is found through application of linear programming techniques which seek to maximise the sum of producer and consumer surplus across the entire market simultaneously. The objective function of this solution, which is well established in economic theory, consists of three terms:

— the integral of the demand price function over demand; minus

— the integral of the supply price function over supply; minus

— the sum of the transportation, conversion and storage costs.

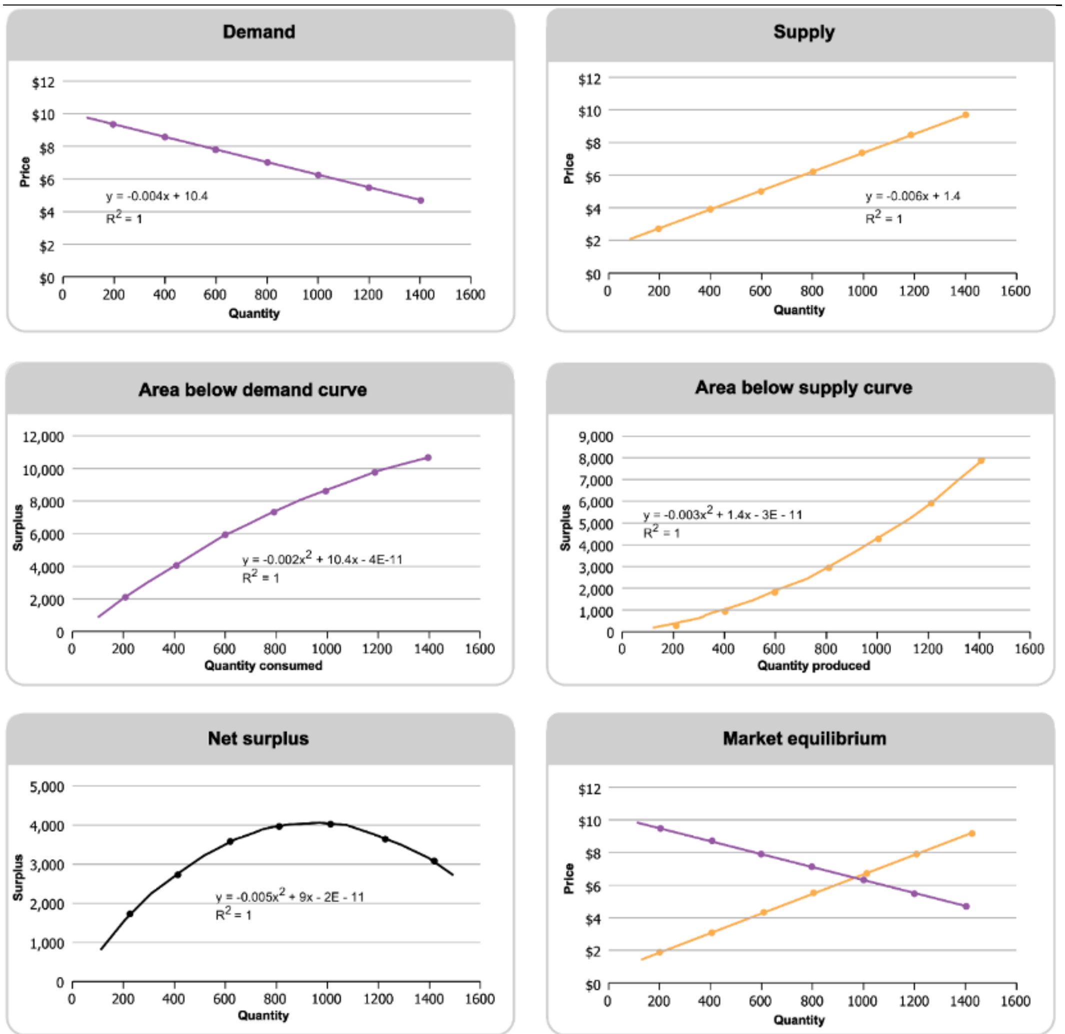
The solution results in an economically efficient system where lower cost sources of supply are utilised before more expensive sources and end-users who have higher willingness to pay are served before those who are less willing to pay. Through the process of maximising producer and consumer surplus, transportation costs are minimised, and spatial arbitrage opportunities are eliminated. Each market is cleared with a single competitive price.

Figure A.1 seeks to explain diagrammatically a simplified example of the optimisation process. The two charts at the top of the figure show simple linear demand and supply functions for a particular market. The charts in the middle of the figure show the integrals of these demand and supply functions, which represent the areas under the demand and supply curves. These are equivalent to the consumer and producer surpluses at each price point along the curve. The figure on the bottom left shows the summation of the consumer and producer surplus, with a maximum clear at a quantity of 900 units. This is equivalent to the equilibrium quantity when demand and supply curves are overlayed as shown in the bottom right figure.

The distinguishing characteristic of spatial price equilibrium models lies in their recognition of the importance of space and transportation costs associated with transporting a commodity from a supply source to a demand centre. Since gas markets are interlinked by a complex series of transportation paths (pipelines, shipping paths) with distinct pricing structures (fixed, zonal or distance based), GMG Australia also includes a detailed network model with these features.

Spatial price equilibrium models have been used to study problems in a number of fields including agriculture, energy markets, mineral economics, as well as in finance. These perfectly competitive partial equilibrium models assume that there are many producers and consumers involved in the production and consumption, respectively, of one or more commodities and that as a result the market settles in an economically efficient fashion. Similar approaches are used within gas market models across the world.

Figure A.1 Simplified example of market equilibrium and settlement process



Source: ACIL Allen

A.1.2 Data inputs

The user can establish the level of detail by defining a set of supply regions, customers, demand regions, pipelines and LNG facilities. These sets of basic entities in the model can be very detailed or aggregated as best suits the objectives of the user. A 'pipeline' could represent an actual pipeline or a pipeline corridor between a supply and a demand region. A supplier could be a whole gas production basin aggregating the output of many individual fields or could be a specific producer in a smaller region. Similarly, a demand point could be a single industrial user or an aggregation of small consumers such as the residential and commercial users typically serviced by energy utility companies.

The inputs to GMG Australia can be categorised as follows:

— **Existing and potential new sources of gas supply**: these are characterised by assumptions about available reserves, production rates, production decline characteristics, and minimum price expectations of the producer. These price expectations may be based on long-run marginal costs of production or on market expectations, including producer's understandings of substitute prices.

— **Existing and potential new gas demand**: demand may relate to a specific load such as a power station, or fertiliser plant. Alternatively, it may relate to a group or aggregation of customers, such as the residential or commercial utility load in a particular region or location. Loads are defined in terms of their location, annual and daily gas demand including daily demand profiles, and price tolerance.

— **Existing, new and expanded transmission pipeline capacity**: pipelines are represented in terms of their geographic location, physical capacity (which may vary over time), flow characteristics (uni-directional or bi-directional) and tariffs.

Existing and potential new LNG facilities: LNG facilities include liquefaction plants, regasification (receiving) terminals and assumptions regarding shipping costs and routes. LNG facilities play a similar role to pipelines in that they link supply sources with demand. LNG plants and terminals are defined at the plant level and require assumptions with regard to annual throughput capacity and tariffs for conversion.

Melbourne
Suite 4, Level 19; North Tower
80 Collins Street
Melbourne VIC 3000 Australia
+61 3 8650 6000

Sydney
Suite 603, Level 6
309 Kent Street
Sydney NSW 2000 Australia
+61 2 8272 5100

Brisbane
Level 15, 127 Creek Street
Brisbane QLD 4000 Australia
+61 7 3009 8700

Canberra
Level 6, 54 Marcus Clarke Street
Canberra ACT 2601 Australia
+61 2 6103 8200

Perth
Level 12, 28 The Esplanade
Perth WA 6000 Australia
+61 8 9449 9600

Adelaide
167 Flinders Street
Adelaide SA 5000 Australia
+61 8 8122 4965

ACIL Allen Pty Ltd
ABN 68 102 652 148

acilallen.com.au