EnergyQuest

A review of gas cap pricing

An independent report prepared by EnergyQuest for APPEA

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ENERGYQUEST

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Summary

As a result of the longer term upward trend in gas prices (following the global trend in oil pricing), recent extreme demand volatility for the winter of 2022, and the Australian Government Budget 2022-23 forecasting gas price increases of more than 40% over two financial years, there have been calls for a gas price cap to limit the exposure of high gas prices to gas users.

At the wholesale level, price caps have the effect of decreasing long term supply as capital investment is deferred or redeployed to higher priced markets or better economic opportunities.

At the retail level, the cost of subsidising gas prices can be enormous – EnergyQuest estimates this would be in the order of $1 billion per year for gas for just spot markets. The risk of getting caught in an energy price cap cycle can be challenging - The UK decreased its Energy Price Guarantee (applicable to gas and electricity) just six weeks after announcing it, and estimates it will now cost $55 billion over six months.

Price caps do not address the cause of high domestic prices - lack of new gas supply and volatility in demand from the electricity market with the transition to renewables.

The long term net effect of a price cap is to increase demand with lower prices, and decrease supply with lower economic returns – the opposite of what is required.

- **Demand:** Lower prices support more demand. Higher prices cause consumers to more actively seek alternatives or more efficient use of the resource – decreasing demand.
- **Exploration:** It is already at record low levels in Australia, and a gas price cap can only decrease the economic drivers for exploring and adding gas resources.
- **Development:** There are discovered gas Contingent Resources of 38,986 PJ (equivalent to 19 years of domestic gas supply), which are currently uncommercial on the east coast and Northern Territory (NT). Higher gas prices improve the ability to commercialise these discovered resources, whereas lower gas price caps can only damage the prospects of development.

  EnergyQuest estimates that the loss of Contingent Resources would remove or delay the supply contribution of 586 PJ from these Resources to 2031 – more than one year's east coast domestic demand (for 2021/22).
- **Storage:** The Victorian seasonal gas demand cannot be met efficiently without gas storage, and this dependency will increase with the decline of the Longford fields. In a price capped market, the ability to buy low priced gas in the off season to sell into the high priced peak winter season is reduced if not eliminated, because the highest price gas can be sold at would be the price cap, and this may even be the price at which the gas was sourced. Storage economics are driven by peak gas prices, which are reduced or eliminated with gas price caps.
- **LNG imports:** There are five projects to develop LNG facilities on the east coast. EnergyQuest estimates that 50% of annual gas supply to the south-east region (NSW, ACT, Victoria, Tasmania and South Australia) will come from LNG imports by 2033. LNG imports are simply not viable with a domestic price cap at or below the suggested $10/GJ, when the average oil-indexed LNG price at Gladstone for 2022 to October was A$18.35/GJ.
- **Government revenue:** Assuming conservatively that the price cap would only apply to wholesale spot sales (16% of total supply), then indicatively a price cap of $10/GJ would lower government revenue in the order of $87 million per year compared to actuals seen in 2021/22.

1. Domestic context and industry drivers

This chapter reviews east coast gas prices for long term gas contracts and spot markets, and identifies key price drivers.

1.1 Long term gas contracts

Long term and bilateral contracts

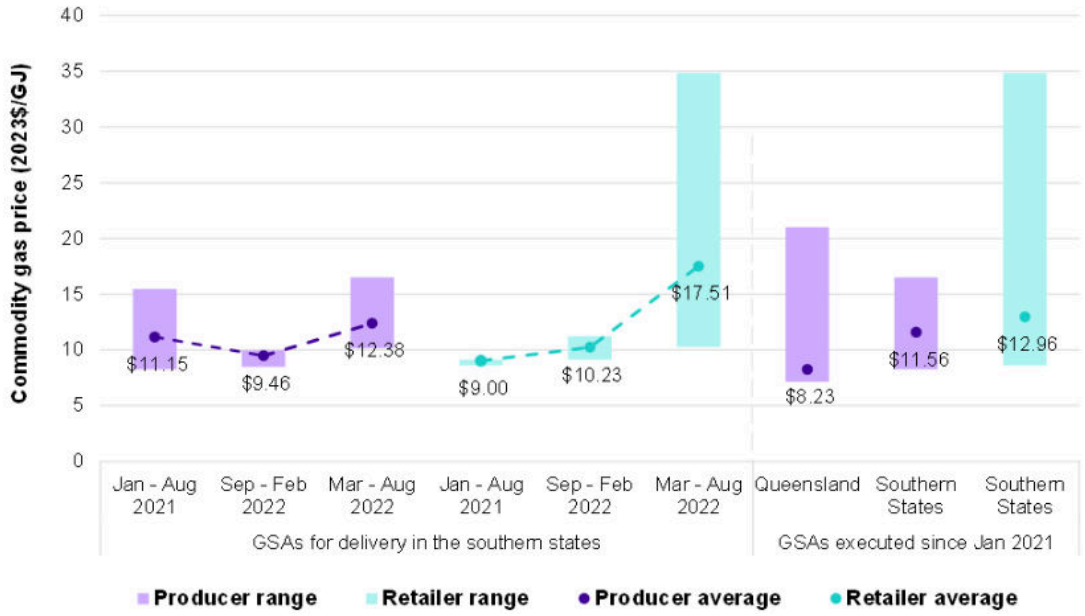
For 2021/22 east coast gas demand was 575 PJ, and for this period the Australian Energy Regulator (AER) reported net spot trade volume (for Victoria, Sydney, Adelaide and Brisbane) of 68 PJ, and 26 PJ of delivered gas for the Wallumbilla Gas Supply Hub (Queensland, WGSH). Some caution needs to be exercised on comparing volumes as there may be multiple trades of the same gas at a trading hub. Nevertheless, the total is still only 16% of the total demand.

The USA and Europe have large, deep spot markets (e.g. Henry Hub and the Dutch TTF respectively) which are commonly used to not only trade short term, but as references for long term contracts. This is not the case for east coast Australia, where typically not more than 16% of gas volumes are spot traded, and the vast majority (84%) of gas sales are long term bilateral agreements[1].

The effect of the large share (estimated at 74% of total gas volume) of gas supply coming from long term bilateral agreements is that the difference between gas spot market prices and the gas price paid under longer term contracts can be quite different.

The ACCC released preliminary price data for longer term gas sales agreements (GSAs) from January 2021 to August 2022 (Figure 1).

Figure 1 Gas commodity prices (2023$/GJ) payable under GSAs in the east coast gas market for 2023 supply



Note: Quantity-weighted average prices are displayed next to the point, or below the price range

Source: ACCC[2]

[1] Bilateral agreements are between two parties without the use of a public trading hub or spot market. The terms are usually confidential.

[2] ACCC, 'Gas inquiry 2017-2025 Interim report January 2023, Preliminary gas pricing', Chart 4, 14 November 2022; https://www.accc.gov.au/regulated-infrastructure/energy/gas-inquiry-2017-25/january-2023-interim-report-preliminary-gas-pricing

The WGSH hub spot price averaged $13.85/GJ from January 2021 to August 2022, but the ACCC reports that the average GSA price for delivery from a producer to Queensland in 2023 was $8.23/GJ – a longer term buyer's price was on average 41% lower than the WGSH spot market.

Similarly for southern states, the average Victorian spot price was $13.28/GJ from January 2021 to August 2022, and the ACCC reports that the average GSA price for delivery to southern states from a producer was $11.56/GJ – a longer term buyer's price was on average 13% lower than the Victorian spot market.

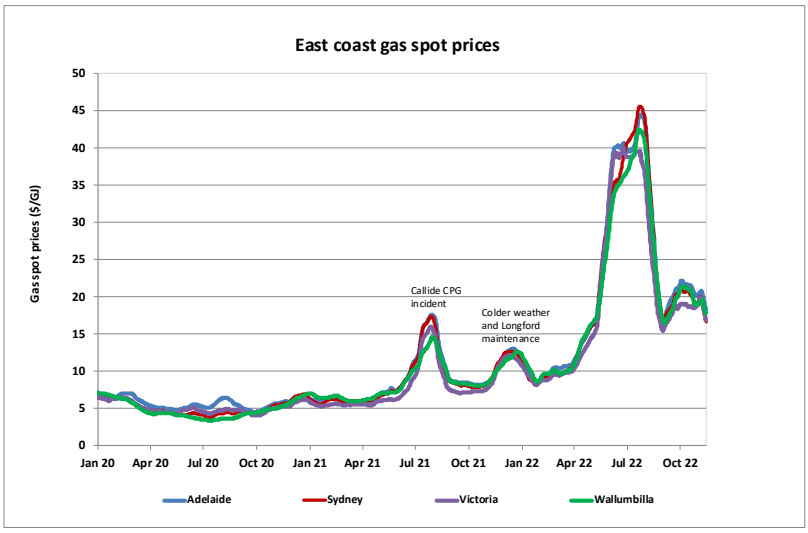
1.2 Gas spot markets

Spot market gas pricing in 2022

For gas consumers, infrastructure providers, energy retailers and gas producers, 2022 has been one of the most difficult years for those involved in the east coast gas market.

The historical gas prices at the east coast key gas trading hubs (WGSH, Victoria, Sydney and Adelaide) increased in July 2022, to more than five times the average 2021 price (Figure 2).

Figure 2 Historical domestic spot prices

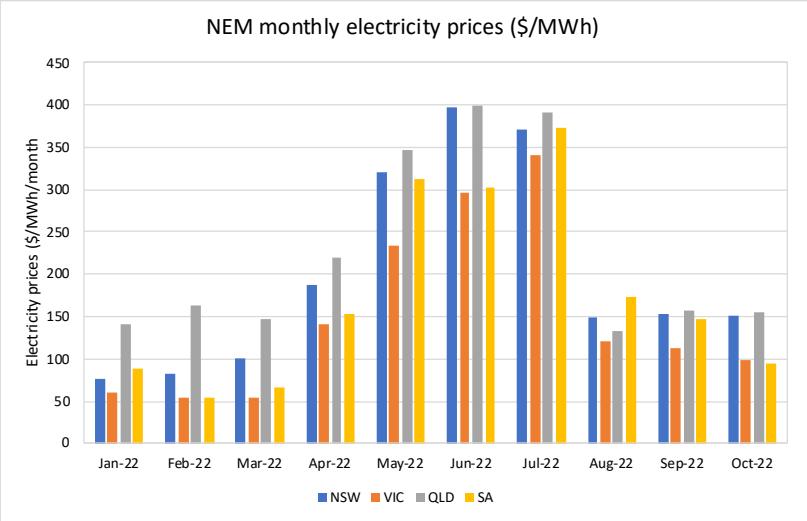


Note: Prices are ex-ante, rolling 30 day average; As Brisbane is smaller and close to Wallumbilla (WGSH), WGSH is shown for Queensland gas spot prices.

Source: AEMO bulletin board

So why the dramatic increase in gas spot prices in the winter of 2022? As the east coast National Electricity Market (NEM) moved into winter mode for 2022, coal-fired power generation (CPG) capacity outages reached a high of around 3.6 GW in late April and then in the second week of June peaked at 4.6 GW, in a system which has a capacity of 53 GW. Electricity prices ramped up in all the NEM states for April to July, particularly in NSW and Queensland (Figure 3).

Figure 3 NEM monthly spot electricity prices ($/MWh)



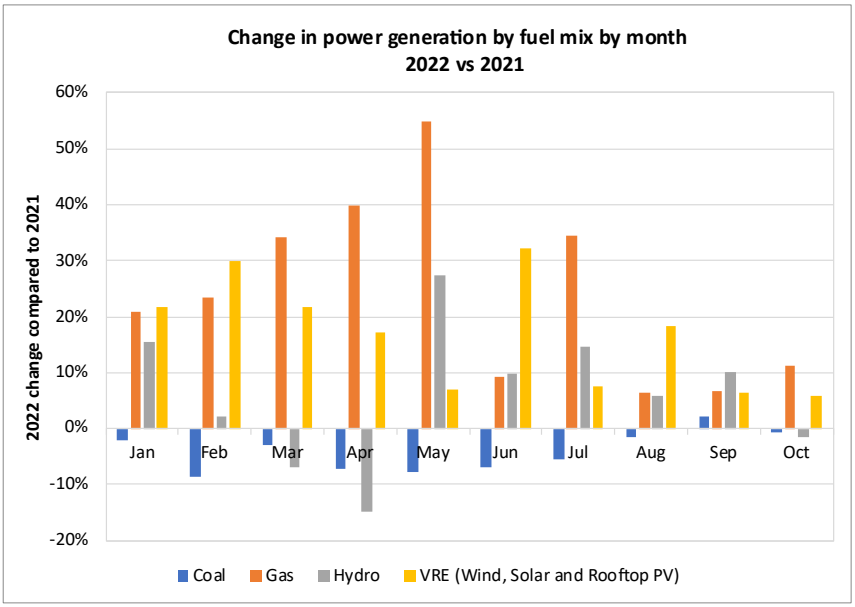
Source: AEMO, EnergyQuest analysis

To everyone's relief, electricity prices more than halved from July to August as demand decreased from winter peaks, supply reliability improved and the market moved through the tightness.

The electricity price drivers can be seen in the changing fuel mix of the power generation. In January and February, the large decreases in CPG were mostly offset by higher variable renewable energy (wind, solar and rooftop PV, VRE) generation. However, from March to May, the increase in VRE was insufficient to offset the decline in CPG, and GPG was increasingly used to meet demand. June saw a large increase in VRE which pushed back on gas, but July saw gas stepping in again to offset the decrease in VRE, then August to October saw a return to a fuel mix similar to 2021.

Given GPG was only a relatively modest 7% of the NEM generated power in 2021, the real impact on GPG can be seen in the percentage change compared to last year (Figure 4). GPG increased by more than 50% in May 2022 compared to 2021, and was up more than 20% in five of the first six months of 2022.

Figure 4 Change in power generation by fuel by month (2022 vs 2021)



Source: AEMO, EnergyQuest analysis

Sourcing the required fuel gas for GPG at short notice was a critical driver of gas spot market prices shown in Figure 3 for April to July.

The Australian Energy Regulator (AER) noted[3] record spot trade attributable to GPG activity during Q2 2022:

> 'Net trade in the downstream gas markets continued to increase following record volumes traded last quarter [Q2 2022], reaching 21.3 PJ. This was primarily driven by the increased trade in Victoria rising by more than 330 TJ. High trade volumes continued due to gas generators purchasing significant quantities to run their gas units at higher output into July, above monthly net purchase volumes across the previous quarter'

These price events demonstrate the extreme sensitivity of the gas spot market to higher electricity demand and power generation interruptions.

Market intervention and gas price caps

The spot market volatility discussed in the previous sections left at least one retailer (Weston Energy) suspended and requiring extreme intervention by AEMO into the gas and electricity markets:[4]

In gas markets:

- Following the suspension of Weston Energy on 24 May 2022 from gas markets, the Sydney market was administered with prices set (not capped) at about $30/GJ due to Weston's large customer load. A subsequent emergency notice from the NSW government directed a change in this administered state to apply an Administered Price Cap (APC) of $40/GJ for 1 – 7 June.
- This subsequent change in pricing reduced the incentive for gas traders to direct gas away from Sydney toward other markets. The APC remained in place until 14 June as a result of cumulative prices exceeding the Cumulative Price Threshold (CPT).
- Also as a result of Weston Energy's suspension, prices were capped in the Brisbane market at the APC at $40/GJ from 24 May – 7 June (10 business days).
- Unrelated directly to Weston Energy's suspension, prices in the Victorian market were also capped at $40/GJ from 30 May to 1 August because of high cumulative prices exceeding the CPT.

In electricity markets:

- On 13 June, prices in Queensland, NSW, Victoria and South Australia were capped at $300/MWh due to high cumulative prices.
- Generators advised that they withdrew capacity after the implementation of this APC due to the high cost of coal and gas generation combined with concerns about fuel availability. The NEM was not able to handle this large withdrawal of capacity, with 406 separate Lack of Reserve conditions declared by AEMO in Q2 2022, compared with 36 in Q1 2022 and 73 in Q2 2021.
- On 15 June, AEMO for the first time suspended the wholesale electricity market in all regions of the NEM. During this period, AEMO manually determined spot prices

[3] AER, 'Wholesale markets quarterly Q3 2022 July – September', p20 November 2022

[4] AER, 'Wholesale Markets Quarterly Q2 2022', p8 April – June 2022; https://www.aer.gov.au/system/files/Wholesale%20Markets%20Quarterly%20Q2%202022.pdf

and allowed for participants to apply for compensation if those prices did not cover their costs.

- On 22 June, AEMO removed the $300/MWh administered price cap when the cumulative price fell below the threshold again. Participants returned their generation capacity to the market and AEMO lifted the market suspension the following day.

This is a case study of the risk to the gas and electricity markets when CPG is not available and VRE is not yet mature enough to pick up the capacity.

1.3 International energy markets and domestic prices

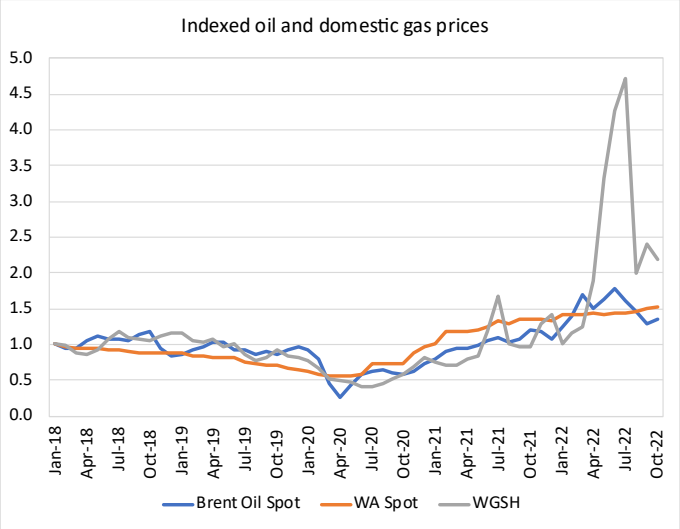
The east coast is connected to international energy markets through the export of thermal coal, and gas as LNG.

This section examines global factors which may influence domestic electricity and gas prices.

Oil and domestic gas prices

Over the last five years, the global oil price and Australian domestic spot gas prices at WGSH on the east coast, and Western Australia have followed similar pricing trends with lower demand through COVID around 2020, and the subsequent recovery. The exception being the WGSH peak from April 2022 over the winter period, which was discussed in the previous section.

Figure 5 Indexed oil and domestic gas prices



Note: Correlation Brent-WA Spot = 80%, Brent-WGSH = 76%

Source: CME, AEMO, gasTrading.com.au

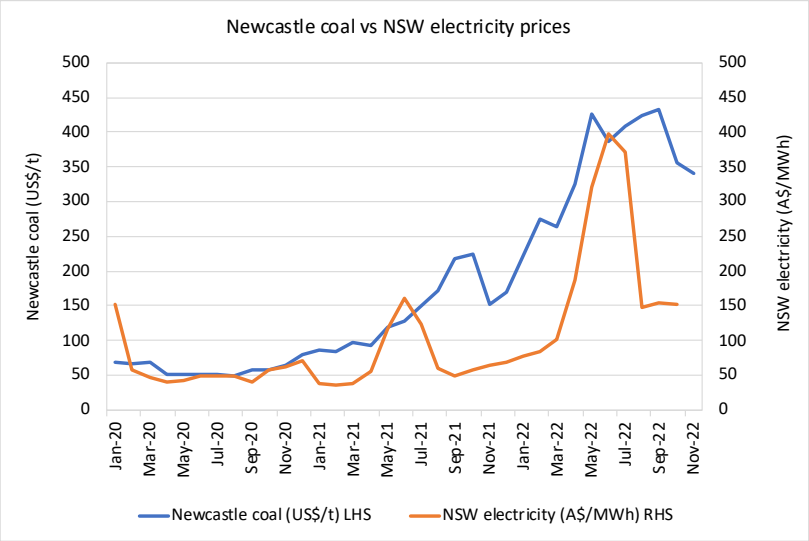
From the depths of the COVID low point June 2020 to March 2022, oil and domestic gas spot prices more than doubled, indicating that Australian domestic gas prices are not in strictly isolated markets, and are impacted by global oil price movements and the world economy. One reason for this connection is that the vast majority (more than 90%) of Australia's LNG exports are sold at prices linked to an oil index, and this may have an impact when, for example the gas net back to east coast gas markets is considered. Another reason is that during high oil price periods, industry costs increase, and capital more actively seeks the best global opportunities, which may not always be in Australia.

Any analysis of gas prices on the east coast should be mindful of the global factors which are beyond Australia's shores and direct control.

Coal prices

Thermal coal prices have increased by a factor of six times from 2020 to 2022, and while this is not well correlated to electricity prices (Figure 6), it does make it more economically challenging to source coal at short notice on the spot market for additional power generation. There is also the additional uncertainty, as seen recently, of NSW floods and the impact on coal operations.

Figure 6 Newcastle coal vs NSW electricity prices



Source: tradingeconomics.com, AEMO

Table 1 shows how the cost of black coal-fired power generation has changed over time with the increase in coal prices.

Table 1 Coal price vs power generation cost

Period	Spot coal commodity price		Coal-fired power generation	Exchange rate
	US$/tonne	A$/GJ	A$/MWh	US$/A$
Coal 2020	60	3.74	33.67	0.69
Coal 2021	141	8.18	73.64	0.75
Coal YTD Nov 2022	351	21.90	197.14	0.70
Sept 2022	434	29.00	261.01	0.65

Notes: Assumes coal heating value of 23 GJ/t, heat rate 9 GJ/MWh

Source: Reserve Bank of Australia, tradingeconomics.com, AER

Fast response open cycle gas-fired power generators with a heat rate around 10.93 GJ/MWh are less efficient than large coal generators, but would have competed in 2022 with gas prices around $18/GJ. More efficient closed cycle gas-fired power generators have a heat rate of around 7.25 GJ/MWh, and could compete with gas prices below $27/GJ. The average gas price for NSW for 2022 to October was $21.71/GJ, but over a range from a very competitive low of $6.45/GJ to a high of $59.49/GJ.

With very high coal prices, this demonstrates why gas was the ‘go to’ fuel when prices were driven to new highs against the coal alternative.

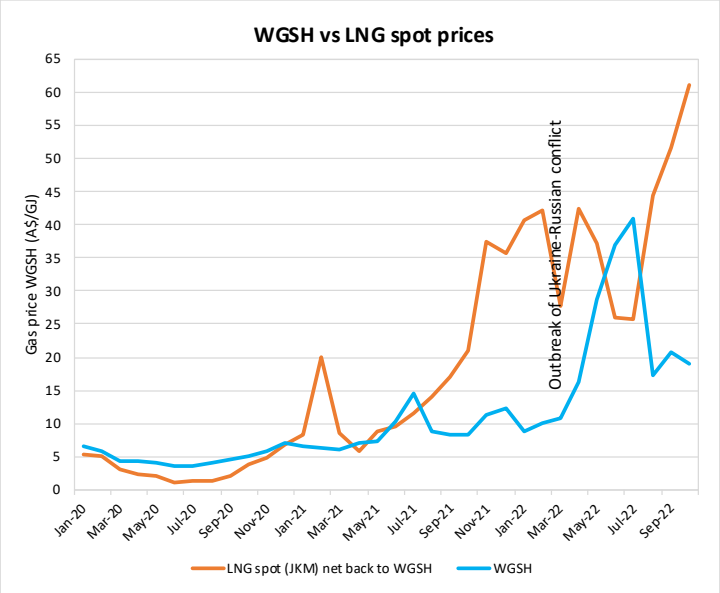
LNG exports

It has been postulated that the Ukraine-Russian conflict has driven international gas price higher, which then flowed back to domestic markets through higher LNG exports from the

east coast. LNG feedstock is a large part of the east coast gas market. For 2021, LNG feedstock was approximately 72% of east coast gas demand.

As shown in Figure 7, the domestic gas prices (at WGSH) are poorly correlated to the LNG spot[5] prices, and in fact the record peak domestic gas prices (June-July 2022) correspond to the lowest LNG spot prices since October 2021. Note also that the increase in LNG spot prices occurred in November 2022, several months before the Ukraine-Russian conflict, and indicative of other global energy difficulties as the northern hemisphere winter approached.

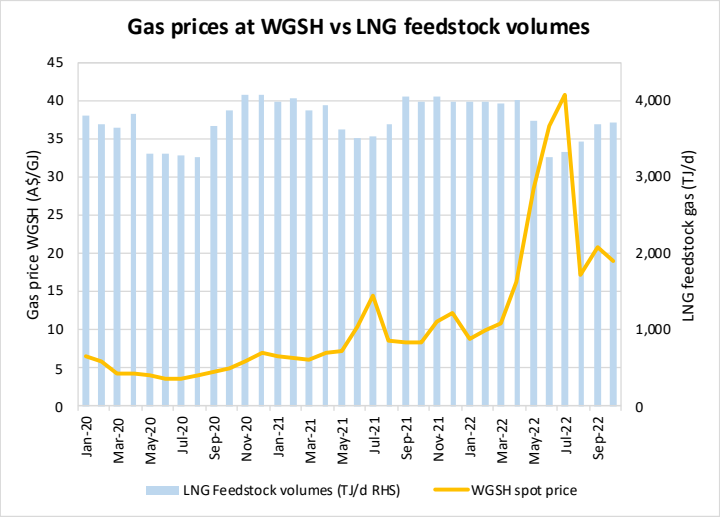
Figure 7 WGSH vs LNG spot prices



Source: Platts, AEMO, EnergyQuest analysis

LNG exports do not correlate to the record high domestic gas prices in June and July 2022, as gas feedstock for LNG exports was at the lowest level since at least January 2020 (Figure 8).

Figure 8 Gas prices at WGSH vs LNG feedstock volumes



Source: AEMO, EnergyQuest analysis

[5] In this paper, LNG spot prices are based on the Platts JKM index which tracks LNG spot trades to Japan, Korea, China and Taiwan.

During the period January 2020 to October 2022, there were major international disruptions to the energy market with shortages in Asia and the outbreak of the Ukraine-Russian conflict, causing high global demand for LNG. Queensland LNG feedstock volumes increased by only 2% from the pandemic-low year of 2020, despite materially increasing international prices – the LNG spot price was up by 1,125% and Brent oil-indexed LNG by 151% (Table 2).

Table 2 LNG feedstock volumes vs gas prices

	Units	2020	2021	2021/2020	2022	2022*/2021	2022*/2020
LNG feedstock volumes	TJ/d	3,657	3,845	5.1%	3,729	-3.0%	2.0%
LNG spot (JKM) net back	A$/GJ	3.26	16.46	404%	39.95	143%	1124%
Brent indexed net back	A$/GJ	6.69	11.42	71%	16.81	47%	151%
WGSH spot price	A$/GJ	4.89	8.88	81%	20.94	136%	328%

Note: *2022 is average to end October 2022; Source: EnergyQuest analysis

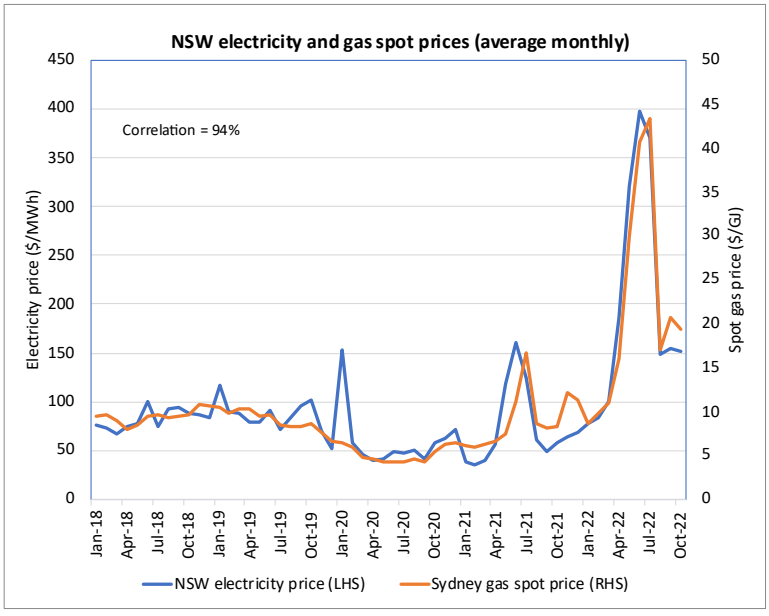
This is consistent with the long-term contracted nature of the Queensland LNG off-take agreements, which committed the projects to long-term relatively fixed LNG volumes with oil-indexed prices. Industry reports estimate that only approximately 6.8% of LNG sold in 2021 from east coast LNG projects were spot sales, noting that some of these spot volumes may have been spot sales by the off-taker after purchasing the LNG under the long term oil-indexed contracts i.e. not spot sales from the LNG projects.

From January 2020 to October 2022, domestic gas prices at WGSH have averaged a 3% discount to international gas prices, such as Brent oil-indexed LNG net back prices.

Power generation

Since at least January 2018, there has been a strong correlation between state electricity and spot gas prices – as seen for example in NSW (Figure 9), the state with the largest electricity demand. This confirms the impact of electricity pricing on gas prices.

Figure 9 NSW electricity and gas spot prices



Source: AEMO, EnergyQuest analysis

Reserve Bank of Australia governor Philip Lowe has issued a blunt warning that the renewable energy transition would probably spark higher and more volatile energy prices in the years ahead[6].

It is clear that a key a part in reducing gas price peaks and volatility, is to ensure the unplanned GPG demand is kept to a minimum, and the transition to renewables is well managed.

2. Gas price caps

The higher gas prices and volatility in 2022, and an Australian Government Budget 2022-23 which forecast[7] gas price rises of 20% in each of 2022-23 and 2023-24, saw some calls for gas price caps. Large gas users were reported[8] [9] to be wanting a cap on domestic gas prices of $10 to $11/GJ. In this report, calculations of the impact of a wholesale gas price cap assume a cap at $10/GJ.

If a regulator wanted to impose a price cap on the gas market, a multitude of possible options and variations exist, and it is beyond the scope of this paper to examine all of them.

At the highest wholesale level, some of the themes and impacts are examined below:

Price caps and wholesale trading hubs

If a price cap is only placed on one wholesale trading hub, then supply offers will simply move away to a higher priced hub.

An example of this occurred when gas price caps were placed on the Victorian gas system in July 2022. AEMO noted[10] that 'the current $40/GJ administered price cap may not offer an incentive to supply gas into the Declared Transmission System (DTS) from outside Victoria'. In other words, AEMO saw price caps lowering the incentive to supply additional gas.

If the price cap is placed on all trading hubs, then the logical action for gas suppliers would be to move to bilateral agreements. This takes a little longer to close out, but would be a logical step if the price difference is material – if it is not, then why have a gas price cap?

One group of gas suppliers more adversely impacted by a price cap on all trading hubs would be smaller producers. They can find themselves short of capital and without sufficient field development to write a long term firm bilateral contract usually required by industrial gas users. Currently a small producer can sell on the spot market to build cash reserves, and the higher prices encourage more supply. A price cap lowers the revenue a smaller gas producer can achieve at a critical stage in the development of gas supply.

One course of action for gas buyers is to decrease any existing contracts they may have to a minimum take, and source cheaper price capped gas from a spot market. This increases the volume sought on the spot market, but without a price signal to balance it. This will benefit larger players e.g. large retailers with trading experience who are able to balance the uncertainty of the available trading hub with existing contract flexibility.

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[6] Australian Financial Review, 'Renewables push to drive up energy prices. Lowe warns', 22 November 2022

[7] Australian Government, 'Budget October 2022-23, Budget Statement 2: Economic Outlook', p57, 25 October 2022

[8] Australian Financial Review, 'Binding gas code, price caps as Labor feels energy pain', 30 October 2022.

[9] Energy Users Association of Australia, 'Energy Ministers understand the seriousness of the gas crisis. Now is the time to act.', 28 October 2022; https://euaa.com.au/energy-ministers-understand-the-seriousness-of-the-gas-crisis-now-its-time-to-act/

[10] AEMO, 'Declared wholesale gas market – intervention report', p6

Bilateral agreements

If the price cap was extended to all new gas sales, including bilateral agreements, then the consequences are more complex.

A gas supplier may assume that gas price caps are not long term and that prices will increase in the future. A logical response could be to leave the gas in the ground until the short gas market is properly priced. This is the opposite situation to when a price cap is being debated, and gas buyers defer contracting in the expectation of lower future gas prices.

Capital for investment in gas development is a global game. A gas supplier must consider the best place to invest in the current energy market. For example, as at 15 November 2022, US gas was trading (Nymex) at US$6.03/MMBtu (A$8.54/GJ) – one of the lowest price gas markets in the world. This is in a country where costs of development are lower than Australia's and the time from starting a well, to gas sales is measured in just a few months – compared to NSW's largest gas field at Narrabri which has been under development and legal challenge for more than a decade. A gas cap in Australia of $10/GJ would risk capital flight to countries which offer a faster and higher return on investment.

There are not many regulatory options in these scenarios, except to extend powers to include control of gas volumes as well as prices, to ensure gas is not withheld from the market – a challenging new regulatory precedent.

The European Commission has been working on a gas price cap with the condition that any cap could not affect long term contracts, lead to an increase in gas consumption or provoke producers to reroute supplies elsewhere. The European Union's executive is reported to have said that this is not possible[11], indicating the difficulty of avoiding unintended consequences.

The European Commission has since looked at just spot gas market volatility and announced[12] a proposal which is 'not a regulatory intervention to set the price on the gas market at an artificially low level. It is a mechanism of last resort to prevent and, if necessary, address episodes of excessively high prices, which are not in line with global price trends'. It applies only when the TTF gas hub exceeds Euro 275/MWh (A$117/GJ) for more than two weeks, and the spread between the TTF gas hub and LNG import prices exceeds Euros 58/MWh (A$24.79/GJ) for ten trading days. These are price levels not seen in Australia to date. This mechanism is clearly aimed at volatility – a clear move away from using a gas cap to lower long term gas prices.

Retail price caps

Gas retailers who deal directly with the majority of gas consumers may be exposed to unexpected risks in working with price caps. Retailers generally have an existing portfolio of gas supply, pipeline and possibly storage service contacts, matched with gas sales agreements. These portfolios are designed to match the retailers risk profile, competitive position and expectation of future gas markets. A retail gas price cap is a market discontinuity which is designed to change buyer profiles and this has to add to the risks for retailers with potential impacts on their existing contracted positions. The recent suspension of Weston Energy is an example of the delicate balance retailers navigate in a volatile energy market. Gas price caps will increase the risk to retailers.

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[11] France 24, EU Commission says gas price cap 'impossible'', 8 November 2022; https://www.france24.com/en/europe/20221108-eu-commission-says-gas-price-cap-impossible

[12] European Commission, 'Opening remarks by Commissioner Simpson', 22 November 2022; https://ec.europa.eu/commission/presscorner/detail/en/speech_22_7088

At the gas sourcing level, a retail gas cap is unlikely to be high enough to allow buying gas profitably from the gas wholesalers, unless there is a direct subsidy to the retailer for providing the service of gas sales.

Focussing only on gas sourced from trading hubs – 16% of the east coast demand of 575 PJ, which is 92 PJ. The average WGSH price for 2022 (to end October) was A$20.94/GJ. To subsidise the gas price down to $10/GJ would be at a cost of $10.94/GJ, or more than $1 billion per annum in support of the gas industry – and this is just for the spot market trades.

Not only would retail price caps add risk to the key retailer positions, it would be a very expensive cost if a subsidy is used. This can be seen in the UK, which has used a retail energy price guarantee approach.

Case Study: UK Retail Energy Price Guarantee[13]

On 8 September 2022. the Prime Minister announced that a new Energy Price Guarantee (EPG) would be introduced from 1 October. This was set at £2,500 (A$4,453) a year for typical levels of consumption and was initially planned to last two years.

Very quickly, the Chancellor of the Exchequer announced on 17 October 2022 that the EPG would now only last six months ending at the end of March 2023. The Government has set up a review to design a new more targeted approach which costs the taxpayer less (it was unaffordable).

Under the EPG the average annual gas and electricity bill for a direct debit customer with 'typical' levels of consumption is £2,500. This is 27% higher than the summer 2022 price cap and 96% higher than the winter 2021/22 price cap. Gas has increased by more over this period; up by 141% since winter 2021/22 compared to a 65% increase for electricity. The EPG caps unit costs and standing charges only, so a household using more than 'typical' levels of energy will face higher bills and vice versa.

The Government has said that the EPG will cost £31 billion (A$55 billion) over the sixth months of the scheme, which indicates why it was revised down so quickly, but still represents a substantial sum.

There is no price subsidy on non-domestic energy, so increases in business energy bills could be larger still, affecting the economic viability of some and feeding through to higher consumer prices in general.

The EPG does not include additional support of £1,200 (A$2,137) targeted at vulnerable, low income households.

3. Economic implications

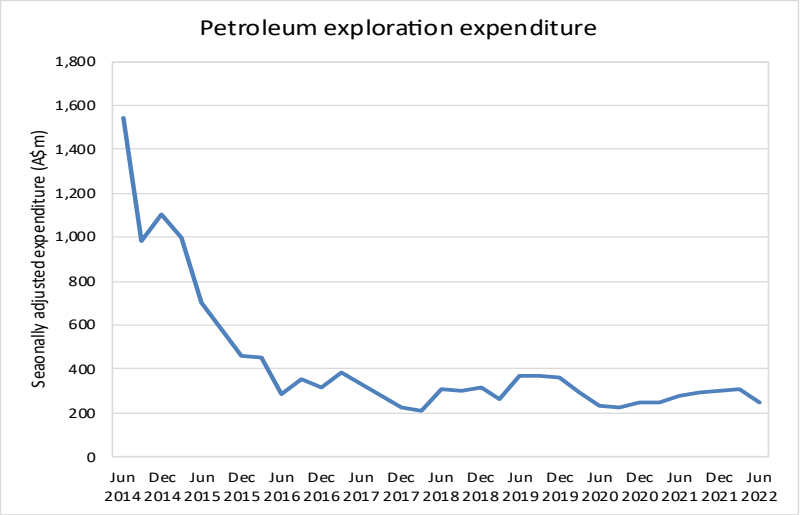
This section examines the potential implications of price caps on the gas value chain.

Exploration

Exploration adds resources to be possibly developed in the future. It is already at historic lows in Australia (Figure 10).

[13] UK Parliament research briefing, 'Domestic energy prices', 9 November 2022; https://commonslibrary.parliament.uk/research-briefings/cbp-9491/

Figure 10 Petroleum exploration expenditure



Source: Australian Bureau of Statistics, Mineral and Petroleum Exploration, Australia June 2022

Capping gas prices can only have a negative impact on exploration expenditure with lower expected revenue from a successful find, to higher perceived regulatory risk with government interventions. These factors would make exploration in other countries increasingly attractive, further decreasing the addition of Australian gas resources from exploration.

Development

Contingent Resources, as defined by the Society of Petroleum Engineers[14] are discovered gas accumulations which are not considered to be commercially recoverable.

The Australian Competition and Consumer Commission (ACCC) reported Contingent Resources for the east coast and NT of 38,986 PJ as at June 2021. This represents a large undeveloped gas resource to potentially meet gas demand, which in 2021 was 2,025 PJ including Gladstone LNG feedstock – the Contingent Resource potential is the equivalent of 19 years of gas supply. However, at the average 2021 gas spot price of $8.88/GJ (WGSH), these Resources were not considered commercially viable. The higher 2022 gas price level of $20.94/GJ (WGSH, average to end October 2022) has the potential to dramatically improve the commercial viability of the Resources, and bring on more supply – an example of high prices improving supply. If a gas price cap is used to hold prices around the 2021 levels, then the development challenge for 38,986 PJ of commercially stranded resources will be unchanged. EnergyQuest estimates that the loss of Contingent Resources would remove or delay the supply contribution of 586 PJ from these Resources to 2031 – more than one year's east coast domestic demand (for 2021/22).

The large CSG fields in Queensland are 89% of the east coast gas 2P Reserves, accounting for 77% of east coast production for the 12 months to end June 2022. Unlike Australia's offshore fields, CSG fields need constant drilling to replace a declining production per CSG well, which is typically in the order of 10% per year. In 2021/22, to maintain a flat production rate, 531 development CSG drills were drilled by the four LNG related operators at an estimated drill, complete and connect cost of $800 million. The majority of this annual investment was based on LNG contract prices. A price cap which is possibly below the alternative LNG net back price cannot encourage the desired additional

[14] Society of Petroleum Engineers, 'Petroleum Resources Classification System and Definitions', accessed 18 November 2022; https://www.spe.org/en/industry/petroleum-resources-classification-system-definitions/

drilling for domestic supply. In fact, a decrease in drilling activity based on the lower economic returns under a price cap, will decrease domestic supply.

Case Study: Argentina

The history of gas in Argentina over the past two decades is one of rolling economic crises and low regulated gas prices that discouraged investment in exploration and development, yet created steady growth in domestic demand. This led Argentina in 2008 to become a net importer of gas with the commissioning of its first LNG receiving terminal located in Bahia Blanca, followed by an FSRU near Buenos Aires, the LNG Escobar, commissioned in 2011. By 2015, the Ministry of Energy, stated that the subsidised gas prices paid by end-users represented only 10 per cent of the actual cost of supply.

Argentina lost its energy security after more than a decade of disinvestment in the energy sector as price caps, capital controls, shaky regulations and high taxes curbed profit potential and made it harder to do business.

The country consumed 1,650 PJ of gas in 2021, and sourced[15] the gas from domestic production of 1,390 PJ, 133 PJ of LNG imports and 162 PJ of pipeline imports from Bolivia. Yet Argentina was a net exporter of gas in 2004, with current world class proven gas reserves of more than 14,000 PJ.

The Argentine Government increased gas prices in February 2022 by 20% to residential customers and 15% to industry, to address the enormous energy subsidies which amounted to around US$11 billion in 2021.

With higher gas prices, the government is betting on an influx of investment to develop the country's huge tight and shale gas resources to regain energy security.

Storage

Gas storage is an increasing part of meeting seasonal swings. In Victoria which has the largest seasonal state demand, the winter demand (approx. 868 TJ/d in 2021) is three times the summer demand (approx. 297 TJ/d). With a single day peak of approx. 1,144 TJ/d seen in 2022.

Much of the supply capacity into the Victorian DTS is provided by Gippsland production, which AEMO forecasts[16] to nearly halve from 972 TJ/d in 2022 to 496 TJ/d in 2026. The Victorian seasonal demand variations cannot be met without gas storage, and this dependency will increase with the decline of the Longford fields.

In a price capped market, the economic drivers to buy low priced gas in the low demand season to sell into the high priced peak winter season is reduced, if not eliminated, because the highest price gas can be sold at what would be the price cap, and this may even be the price at which the gas was sourced.

The proposed, but not committed, Golden Beach storage is a project based in the Gippsland Basin which could add 250 TJ/d of gas underground storage withdrawal capacity. It has not reached final investment decision, and a price cap must be an increased challenge to its economic viability.

[15] BP, 'BP statistical review of world energy', 2022 71st edition.

[16] AEMO, 'Victorian gas planning report update', p24, March 2022; https://aemo.com.au/-/media/files/gas/national_planning_and_forecasting/vgpr/2022/2022-victorian-gas-planning-report-update.pdf?la=en

LNG imports

There are five projects to develop LNG facilities on the east coast. EnergyQuest estimates that 50% of annual gas supply to the south-east region (NSW, ACT, Victoria, Tasmania and South Australia) will come from LNG imports by 2033.

LNG imports could be from Australian sources such as Western Australia, NT or Queensland, or other overseas suppliers, and provide seasonal swing and daily peak capacity for tight supply situations. LNG imports are a key option pursued in Europe following gas supply interruptions from Russia.

LNG imports are simply not viable with a domestic price cap at or below $10/GJ, when the average oil-indexed LNG price at Gladstone for 2022 to October is A$18.35/GJ (before liquefaction costs are considered).

Government revenue

The federal and state governments add specific taxes and royalties to gas production, with the actual revenue raised from gas production dependent on where the gas produced. Government revenue would be impacted with a gas price cap that lowers wholesale gas prices.

Gas produced more than three nautical miles offshore is administered by the federal government and a Petroleum Resources Rent Tax (PRRT) is applicable. The PRRT calculation can be quite complicated, but is generally 40% of taxable profit which includes allowances for deductible (including capital expenditure) and certain exploration expenditure. PRRT collections of $602 million attributable to Bass Strait for 2020/21 were reported[17] by the Australian Government.

Onshore gas production, and offshore production within three nautical miles of the coast has a state based royalty applied. The royalty rate applied in each state is 10% of wellhead value (with some allowable deductions), with a slightly lower rate for Queensland domestic gas production using the state's applicable sliding rate royalty scheme[18].

While it is not possible to precisely calculate the impact of a price cap given the detailed and project specific deductions that make up the calculation, and the unknown details of the gas contracts, an indicative estimate based on some assumptions can be made (Table 3).

[17] Australian Government, '2020-21 Report of Entity Tax Information', 2 November 2022; https://www.data.gov.au/data/dataset/corporate-transparency/resource/80a01133-4281-43ce-b5ef-5535d61e1c1f?inner_span=True

[18] Queensland Government, Business Queensland, 'Petroleum royalty rates from 1 October 2020'; Accessed 30 November 2022; https://www.business.qld.gov.au/industries/mining-energy-water/resources/minerals-coal/authorities-permits/payments/royalties/petroleum-royalty/royalty-rates

Table 3 Indicative government revenue impact of a price cap at $10/GJ

Domestic supply	Units	2022/21	2021/20		
Onshore QLD	PJ	92	128		
Onshore non-QLD	PJ	105	118		
Onshore	PJ	197	246		
Offshore	PJ	385	352		
Total	PJ	582	598		
Spot sales at 16%	PJ	93	96		
Spot gas prices		**Actual**	**Actual**	**Capped Price**	**Capped less 22/21 actual**
Victoria	A$/GJ	14.58	5.70	10.00	-4.58
WGSH	A$/GJ	14.55	6.10	10.00	-4.55
Onshore Royalties					
Queensland	A$/GJ	1.11	0.27	0.66	n/a
Non-Queensland	A$/GJ	1.46	0.57	1.00	n/a
Tax revenue					
PRRT on spot sales	$m	246	96	169	-73
State royalty	$m	41	16	27	-14
Total	$m	287	113	195	-87

Notes: Assumptions 16% of total supply is spot traded and gas price capped. No price impact on other gas supply. Capped Price uses 2022/21 volumes. Prorated PRRT to 2021/22 from 2021/20 actuals.

Source: Australian and state government web sites, EnergyQuest analysis

Assuming that the price cap would only apply to wholesale spot sales (16% of total supply), then indicatively a price cap of $10/GJ would lower government revenue in the order of $87 million per year compared to actuals seen in 2021/22.

OECD analysis

The OECD Economic Outlook[19] 2022 examined energy price caps, and noted that:

'Energy support measures need to be well-targeted, preserve incentives for energy savings and not outlast the period of exceptional price pressures. Price caps and reduced energy taxes on energy, though simpler and faster to implement and thus often an understandable first line of defence, entail high budget costs and a number of other drawbacks, especially in the likely scenario of energy remaining expensive for an extended period. Careful design is needed to ensure price support does not weaken incentives to reduce energy consumption or hamper reallocation by preserving energy-intensive activities that are not sustainable in the medium term'.

4. Conclusions

As a result of the longer term upward trend in gas prices (following the global trend in oil pricing), recent extreme demand volatility for the winter of 2022, and the Australian Government Budget 2022-23 forecasting gas price increases of more than 40% over two financial years, there have been calls for a gas price cap to limit the exposure of high gas prices to gas users.

At the wholesale level, price caps have the effect of actually decreasing long term supply as capital investment is deferred or redeployed to higher priced markets or better economic opportunities.

[19] OECD iLibrary, 'Economic Outlook, Volume 2022 Issue 2: Preliminary version', accessed 23 November 2022; https://www.oecd-ilibrary.org/sites/f6da2159-en/1/3/1/index.html?itemId=/content/publication/f6da2159-en&_csp_=761d023775ff288a22ebcaaa183fbd6c&itemIGO=oecd&itemContentType=book

The European Commission has worked at capping energy prices, but its most recent approach only addresses price volatility and clear market inefficiencies, with trigger prices well above east coast gas pricing.

At the retail level, the cost of subsidising gas prices can be enormous – EnergyQuest estimates in the order of $1 billion per year for gas. The risk of getting caught in an energy price cap cycle can be staggering - The UK decreased its Energy Price Guarantee (applicable to gas and electricity) just six weeks after announcing it, and estimates it will now cost $55 billion over six months.

Gas price caps do not address the fundamental drivers of higher gas prices which are a lack of supply, and demand volatility caused by electricity generation transition issues.

A gas price cap has substantial long term economic implications, impacting the entire gas value chain:

- **Exploration:** It is already at record low levels, and a gas price cap can only decrease the economics of exploring and adding gas resources
- **Development:** There are discovered Contingent Resources of 38,986 PJ (equivalent to 19 years of gas supply), which are currently uncommercial on the east coast and NT. Higher gas prices improve the ability to commercialise Contingent Resources, whereas lower gas price caps can only damage these prospects.
- **Storage:** Storage economics are driven by peak gas prices, which are reduced or eliminated with gas price caps.
- **LNG imports:** LNG imports are simply not viable with a domestic price cap at or below the suggested $10/GJ, when the average oil-indexed LNG price at Gladstone for 2022 to October is A$18.35/GJ.

The long term net effect of a price cap is to increase demand and decrease supply – the opposite of what is required.

Abbreviations

1P	proved reserves
2P	proved and probable reserves
2C	best estimate contingent resources
ACCC	Australian Competition and Consumer Commission
ACT	Australian Capital Territory
APC	Administered Price Cap
AEMO	Australian Energy Market Operator
APPEA	Australian Petroleum Production & Exploration Association
AER	Australian Energy Regulator
bbl	barrel (159 litres or 35 imperial gallons)
bbl/d	barrels per day
CCGT	combined cycle gas turbine
CO_2	carbon dioxide
CO2e	carbon dioxide equivalent
CPG	coal-fired power generation
CPT	Cumulative Price Threshold
CSG	coal seam gas
DTS	Declared Transmission System
DWGM	Declared wholesale gas market (Victoria)
EIA	Energy Information Administration
EPG	Energy Price Guarantee
EU	European Union
FID	final investment decision
FSRU	floating storage and regasification unit
FY	financial year
GPG	gas-fired power generation
GJ	gigajoule (1 billion joules or 10^9)
GPG	Gas-fired power generation
GSA	Gas supply agreement
GSOO	Gas Statement of Opportunities
GW	gigawatt
GWh	gigawatt hour
IEA	International Energy Agency
JCC	Japanese customs-cleared crude (Japanese crude cocktail)
JKM	Platt's Japan Korea Marker
JV	joint venture
km	kilometre
kt	thousand tonnes
LNG	liquefied natural gas
kbbl	thousand barrels
kbbl/d	thousand barrels per day
MJ	million (10^6) joules
MMbbl	million barrels
MMbbl/d	million barrels per day
MMboe	million barrels of oil-equivalent
MMboe/d	million barrels of oil-equivalent per day
MMBtu	million British thermal units
MMBtu/d	million British thermal units per day
MMscf	million cubic feet

MMscf/d	million cubic feet per day
MMcm	million cubic metres (35.31 million cubic feet)
MMscf/d	million standard cubic feet per day
MOU	memorandum of understanding
Mt	million tonnes
Mtpa	million tonnes a year
MW	megawatt
MWh	megawatt hour
NEM	National Electricity Market
NSW	New South Wales
NT	Northern Territory
OCGT	open cycle gas turbine
OECD	Organisation for Economic Co-operation and Development
PJ	petajoule (one thousand terajoules)
PJ/a	petajoules a year
PKET	Port Kembla Energy Terminal
PL	Production licence
PRMS	Petroleum resources management system (Society of Petroleum Engineers)
PRRT	Petroleum Resources Rent Tax
STTM	Short Term Trading Market
SUG	System Use Gas
T	metric tonne
Tcf	trillion cubic feet (10^{12} or one thousand billion)
TJ	terajoule (one thousand gigajoules)
TJ/d	terajoules per day
TTF	Dutch Title Transfer Facility
TWh	tera watt hours (1,000,000 megawatt hours)
VRE	variable renewable energy
WA	Western Australia
WGSH	Wallumbilla gas supply hub

Conversion factors

EnergyQuest converts the measures used by different companies to a consistent basis. In line with Australian industry conventions, we use joules for domestic gas, barrels for oil and condensate and tonnes for LPG and LNG. Where available we use individual company conversion ratios. Otherwise we use:

crude oil 1 barrel (bbl) = 1 barrel oil-equivalent (boe)
sales gas 1 petajoule (PJ) = 171,937 boe
sales gas 1 billion cubic feet (Bcf) = 1.06 PJ
LPG 1 tonne (t) = 8.458 boe
LNG 1 million tonnes (Mt) = 55.43 PJ
LNG 1 million tonnes (Mt) = 9531 Kboe
LNG 1 cubic meter = 0.4157 tonnes
condensate 1 barrel = 0.935 boe
ethane 1000 tonnes = 0.05181 PJ
ethane 1 PJ = 15.1 MMcm
oil/condensate 1000 barrels = 158.97 kilolitres
LPG 1000 tonnes = 1.88 ML
sales gas 1 petajoule (PJ) = 26.71 MMcm
British thermal units 1 million (MMBtu) = 1.055 GJ = 1Mcf = 10 therms
British thermal units 1 billion Btu = 1.055 TJ = 1 MMcf
British thermal units 1 trillion Btu = 1.055 PJ = 1 Bcf
Electricity 1 PJ = 277.8 GWh

EnergyQuest's Terms and Conditions of Supply

EnergyQuest Pty Ltd 139 665 295 as trustee for the EnergyQuest Trust ABN 18 503 484 404 (**EQ**)
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About these terms

1. The Client acknowledges having had fair opportunity to read, understand and negotiate with EQ regarding these terms.
2. Subject to any special written offer by EQ or as EQ may agree in writing, these terms form part of each contract for EQ to supply to the Client either:
   2.1. a publication of EQ not commissioned by a particular Client (such as EnergyQuarterly, Australian LNG Monthly report, East Coast Gas Outlook), a Multi-client Report (MCR); or
   2.2. a report or recommendation of EQ commissioned by a particular Client (a **Consultancy**).
3. The Client accepts these terms if after receipt of a copy of these terms or being able to access these terms on EQ's website, the Client places an order for an MCR or Consultancy. The Client's failure to acknowledge these terms is not evidence these terms do not apply. These terms negate any terms the Client may issue.
4. At any time EQ may change these terms by so notifying the Client or by an alert on EQ's website. Any such change applies to any contract for an MCR or Consultancy that forms 2 days after the change was so notified or alerted.

Multi-client Reports

5. If the Client subscribes to an MCR as Single User, the Client must nominate a single team (maximum 3 people) in its enterprise to be afforded access to the MCR; if subscribing as a Corporate User the Client may allow any people in its enterprise to access the MCR.
6. The Client must not allow any other person/s (individuals, consultants, investors, joint venture partners, corporations or government bodies) access to the MCR or any extract from it. Nor may the Client cite or reference the MCR (or extract from it) in any material published in any form by or for the Client, without the written permission of EQ.
7. An MCR is necessarily of a general nature, does not constitute advice based on the particular circumstances of the Client and must not be relied on in making decisions in the Client's enterprise.
8. Unless otherwise stated, material in an MCR (includes text, images, tables and graphics) is copyright of EQ.
9. EQ reserves the right to suspend or terminate a subscription without giving reasons, subject to refund of any subscription fee paid to EQ in advance.

Consultancy

10. Any promotional materials EQ publishes only give a general idea of its services on offer and cannot be relied on for any purpose.
11. EQ is not competent or licensed to provide financial services advice (such as whether to acquire, hold, vary or dispose of an investment), taxation advice, legal advice, valuation advice, engineering or technical advice, and if the Client has need of that advice they should always seek it from a qualified person.

12. Unless otherwise stated, an EQ quotation for a Consultancy expires 30 days after sent. A quotation for a stated scope of work is only valid for that particular scope. EQ may vary / withdraw its quotation before EQ in fact receives the Client's acceptance of the quotation.

13. If the Client wishes to engage EQ as a consultant, a contract for the Consultancy (**Consultancy Contract**) only forms when EQ either agrees in writing (including by email exchange) or commences work for that Consultancy.

14. A Consultancy Contract is comprised of these terms as read with and subject to the 'brief' (scope of work, timetable and other particulars) as last issued by the Client before the Consultancy Contract formed. The brief may not change thereafter except with EQ's consent. Consent may be conditional, such as a revision of the fee to be paid to EQ. If the brief changes, these terms also apply to the brief as changed. A Consultancy Contract may only be modified or cancelled as the parties agree in writing (includes by email exchange).

15. If for a Consultancy EQ reasonably requires from the Client any direction, information or access to the Client's staff or records or premises, the Client must provide that input promptly and without charge.

16. If in a Consultancy EQ acts on a direction given by the Client that action is wholly at the Client's risk.

17. If in a Consultancy EQ uses information sourced from the Client or from a third party believed by EQ to be reputable, EQ may rely on that information without enquiry and the use of that information is wholly at the Client's risk. If the Client is the source of such information the Client warrants it has right to disclose that information to EQ and that the information does not infringe any third party's rights or applicable law.

18. If for a Consultancy the Client provides any proprietary information (such as infrastructure information or survey data) to EQ, EQ does not obtain any ownership or security interest in that information, and in addition to term 27 (confidentiality) EQ may use that information only for the purposes of the Consultancy. The Client may require EQ to destroy or erase permanently that information in EQ's possession or control when the Consultancy terminates.

19. The Client acknowledges that EQ almost exclusively conducts this work in a Consultancy through the use of subcontractors. EQ acknowledges that it remains liable for the due performance of the Consultancy notwithstanding EQ’s use of subcontractors in the course of the Consultancy.

20. EQ must immediately notify the Client if EQ becomes aware of EQ having a conflict of interest or a significant risk of a conflict in performance of the Consultancy Contract. If EQ has a conflict of interest that cannot be managed to the Client's satisfaction, the Client may terminate the Consultancy Contract without penalty.

21. Where in a Consultancy EQ issues an oral or written report or opinion (a **deliverable**):

    21.1. any historical information therein is not necessarily an indicator of future performance;

    21.2. any estimate, projection or forecast therein would be based on various assumptions (which might not be stated) and on subjective beliefs, opinions and estimates of EQ as of the date the deliverable issues;

    21.3. EQ is not obliged to update any forward-looking information as above if those beliefs, opinions or estimates should change or to reflect other future developments;

    21.4. the deliverable is confidential to EQ and the Client must not, without EQ’s written approval, allow any person (individuals, consultants, investors, joint venture partners, corporations or government body) outside the Client's enterprise to access the deliverable (or extract from it). In addition the deliverable must not be cited or referenced in any material published externally by the Client without EQ’s written approval;

21.5. unless otherwise stated, the deliverable (includes text, images, tables, calculations, models, graphics and Intellectual Property) is and remains the property of EnergyQuest. The Client has a non-exclusive, non-assignable, irrevocable licence to use and reproduce the deliverable for, and only for, the purpose for which originally intended and known to EQ, conditional upon the Client having paid EQ for that deliverable.

22. Unless otherwise agreed in writing (includes by email exchange), EQ would charge a fee for a Consultancy in Australian dollars (AUD) (exclusive of GST), for payment by the Client in AUD within 30 days after completion of the Consultancy and by electronic transfer in clear funds to a bank account nominated by EQ in exchange for an invoice from EQ. However, if the Consultancy is expected to run for an extended period EQ may issue interim invoices monthly with a final invoice to follow after completion of the Consultancy.

23. In addition to such fee, EQ may recover from the Client an amount equal to the GST for which EQ becomes liable by the Consultancy being a taxable supply to the Client, conditional upon EQ issuing a tax invoice for that payment.

24. EQ may not claim against the Client for any cost or expense (other than GST) EQ incurs in a Consultancy as an addition to its fee except to the extent provided for in the Consultancy Contract or approved in writing by the Client.

25. The Client must not deduct from EQ's invoice/s any set off, counterclaim or rebates asserted by the Client or other sum (such as taxes, charges).

26. If payment of EQ's invoice is late, then in addition to its other rights and remedies EQ may recover from the Client daily interest at 10% per annum on the unpaid amount calculated from the date the payment was due. Interest not paid for 30 days adds to the debt (is capitalised), and thereafter attracts interest.

27. A party to a Consultancy Contract must not at any time make improper use or disclosure of any information about the affairs of the other party or any information the use or disclosure of which information is regulated by the *Privacy Act 1988*, or the *Australian Privacy Principles* obtained in negotiations for, or in performance of, the Consultancy Contract. The fact and terms of the Consultancy Contract are information to which the above applies to the benefit of all parties jointly. To obtain a copy of EQ's *Privacy Policy*, contact EQ.

28. Subject to term 20 (conflict of interest) and term 27 (confidentiality), a Consultancy does not prevent EQ from consulting to any third party, such as a competitor of the original Client.

29. EQ must use reasonable care in carrying out a Consultancy. Otherwise, EQ does not give any other warranty, condition or guarantee in connection with the conduct of the Consultancy unless required by law (for example, *Australian Consumer Law*).

30. As a continuing obligation (including after the Consultancy Contract terminates) the Client indemnifies and holds harmless EQ against any claim for any loss, damage, personal injury or death to the extent caused by the Client's improper distribution, sharing or use of a deliverable.

31. EQ accepts no liability to anyone other than the Client. The Client may not assign or declare a trust of a Consultancy Contract or the benefit of a service in the Consultancy without EQ's prior written consent.

32. The Client agrees that EQ’S total liability in respect of any claim pertaining to the Consultancy Contract shall not exceed, in monetary terms, three times the quantum of EQ’s fee (excluding GST) for its performance of the Consultancy Contract.

33. If in a Consultancy Contract, the Client is more than 1 person, that contract binds each such person jointly and severally, and each of them is taken to have authority to bind the other/s in connection with the contract, including that a notice to / from any such person is notice to / from

all of them. If the Client nominates a third party as the recipient of service in a Consultancy or as the addressee of an invoice for the Consultancy, the initial Client remains liable.

34. A party is not liable for a failure to perform a Consultancy Contract to the extent its performance is prevented by a circumstance not within that party's reasonable control and without its negligence.

35. Any provision of a Consultancy Contract that is unenforceable at law must be read down to the extent necessary to avoid that result, or if it cannot be read down it must be severed without affecting the validity and enforceability of the remainder of the contract.

36. A Consultancy Contract constitutes the parties as independent contractors and not as partners, joint venturers, principal and agent, or trustee and beneficiary for any purpose.

37. The laws in South Australia govern a Consultancy Contract, and EQ has exclusive right to nominate the court in which any legal action is to be commenced and conducted. The parties submit irrevocably to the jurisdiction of those courts, and any courts that have jurisdiction to hear appeals from those courts.

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