Wholesale Markets Quarterly

Q3 2022

July – September

November 2022

AUSTRALIAN ENERGY REGULATOR

Australian Government

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Contents

Summary

June and July 2022 were the most tumultuous months in the history of Australia's energy markets. This quarterly report examines what happened to wholesale gas and electricity prices in the months that followed.

In June and July, high winter demand at a time of acute tightening of gas and electricity supply drove soaring energy prices. International coal and gas prices climbed sharply. At the same time, the Iona southern gas storage dropped to record low levels for July and that scarcity of gas influenced higher domestic gas and electricity prices. A number of coal plant experienced outages and fuel supply issues. The need to cover high fuel costs or to ration fuel or water levels caused participants to offer their capacity into the NEM at progressively higher prices, and very expensive gas and hydro generation was needed to meet demand.

As we came out of winter into spring, and demand for heating fell, domestic gas prices eased substantially, falling from record levels in July ($40/GJ) to half that in August ($20/GJ). However, this was still twice as high as August 2021. Average quarterly gas prices across Q3 2022 were around $26/GJ. Wholesale electricity prices also fell to less than half the prices observed in July, as many of the drivers of high prices eased. However, average electricity prices in Q3 2022 were the second highest on record, ranging from $210/MWh in Tasmania to $257/MWh in South Australia.

Combined with lower demand, additional domestic gas supply also eased pressure on prices, delinking them from soaring international prices. Increased renewable generation, fewer baseload outages and an easing of fuel supply constraints also helped lower electricity prices in August and September.

International energy prices (gas, thermal coal and oil) continued to rise over the quarter and are expected to remain high in 2023 and 2024. They will continue to put pressure on domestic prices. Forward markets indicate relatively high domestic gas and electricity wholesale prices will continue into 2023 and 2024.

Spring generally brings favourable conditions for wind and solar generation. This, and the contribution of new wind capacity installed over the past year saw wind output reach record levels in August. While private investment in new electricity generation capacity has slowed over 2022, there are many large-scale batteries in the development pipeline, which will support the integration of renewable generation.

Electricity markets at a glance

Q3 2022

Spot prices

Average quarterly prices double previous Q3 records but down from Q2

Demand

Winter demand eased. Record Q3 high demand in Qld followed by record Q3 low demand in SA and Victoria

Outlook

2023 prices expected to remain high, especially in NSW and QLD

Generation

Supply side pressures remain – high international fuel prices, aging coal plant, imminent Liddell closure and wet weather

Fuel Costs

Coal prices still high, gas prices halved from record highs

New capacity

Less new entry in 2022 compared to previous years

Gas markets at a glance

Q3 2022

Spot prices

Local prices in August & September reduced significantly from record July levels, but remain historically high

High price expectations

ASX futures pricing indicates ~$30/GJ gas in Q2 and Q3 2023

Spot Trade

Downstream trade quantities exceeded last quarter's record, complimented by record Gas Supply Hub deliveries upstream

Day Ahead Auction

Q3 2022 auction quantity won exceeded last quarter's record reaching 21.6 PJ

Gas storage

Gas storage at record low levels, while southern storage at Iona increased over August

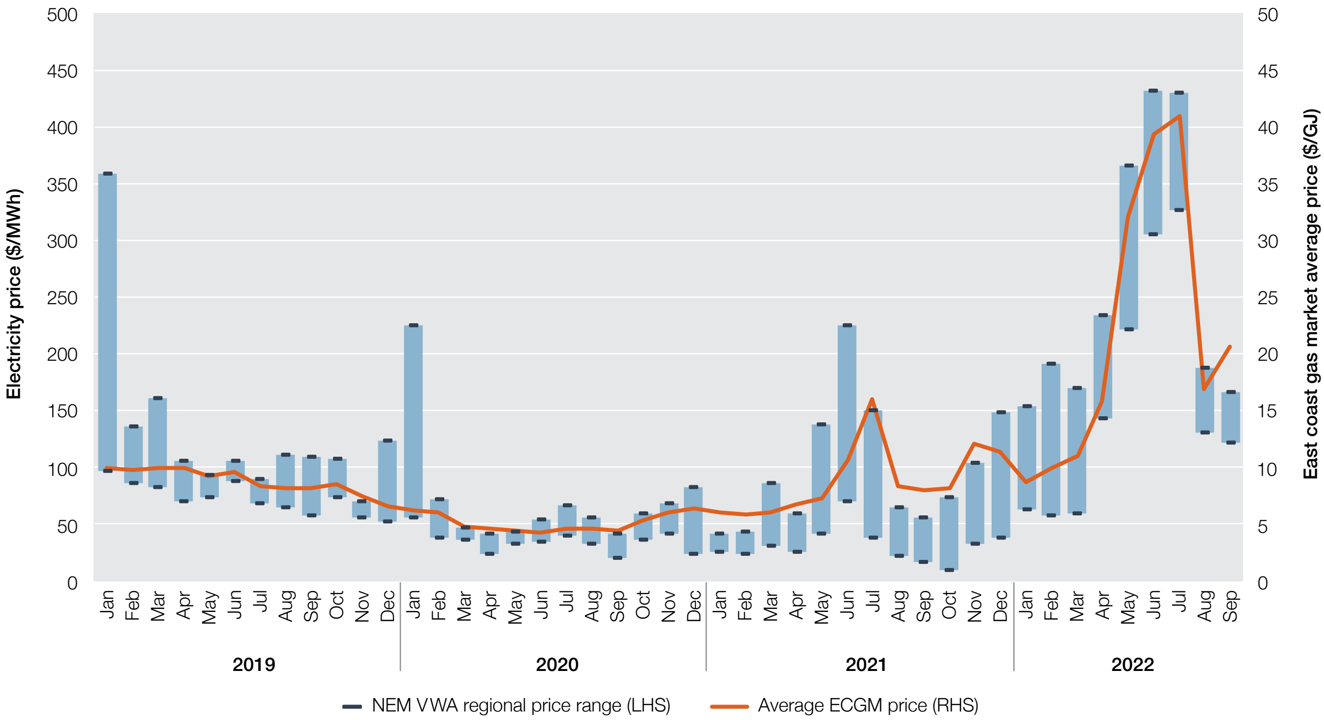
New capacity Certificates Regime

Capacity certificates will replace the AMDQ regime from 1 January 2023 in Victoria

1. Prices halved from July levels but remain high

Over winter, average domestic spot prices for electricity and gas across the east coast increased to unprecedented highs (Figure 1.1). Electricity prices soared in all regions and domestic gas prices rose above international price parity levels. In August and September, both electricity and gas prices reduced significantly but remained historically high.

Figure 1.1 Spot prices peak in July then ease in August and September in electricity and gas markets



Source: AER analysis using NEM data and gas data.

Note: The blue columns show the range of average monthly volume weighted wholesale electricity prices across the NEM regions. A large column illustrates a large variation between regions, while a short column shows prices are relatively similar across regions. NEM prices reflect the Administered Price Caps on prices (limiting prices to $300/MWh) from 15 to 24 June. The orange line shows the average monthly east coast gas market (ECGM) prices. The prices in May onwards include periods of price setting and administered price caps.

1.1 Q3 2022 electricity prices were the second highest on record

Average (VWA) quarterly electricity prices fell in Q3 2022 in all regions from the record levels experienced in Q2 2022 but remained the second highest on record (Figure 1.2). Q3 2022 prices ranged from $210/MWh in Tasmania and Victoria, to around $250/MWh in South Australia, Queensland and NSW. These prices were double previous Q3 records and 4 to 8 times higher than the same quarter last year. The high average price was largely driven by high winter prices continuing into July.

Figure 1.2 Average quarterly electricity prices ease slightly but remain very high

Source: AER analysis using NEM data.

Note: Volume weighted average quarterly price is weighted against native demand in each region. The AER defines native demand as the sum of initial supply and total intermittent generation in a region.

1.2 Record July prices in gas and electricity wholesale markets

Both international and domestic pressures pushed domestic gas and electricity prices to record levels in July 2022.

The average east coast gas price almost quadrupled from around $10/GJ in March to $40/GJ in July. July experienced high winter demand for gas and for gas-powered generation, especially in the southern regions (section 2.1).[1] Normally winter demand is met by a combination of stored gas and flows from Queensland to the south. While gas did flow south, the flows were 12% lower in July 2022 than in July 2021, and the gas was expensive, reflecting high international gas prices. Iona gas storage levels in Victoria, which were already low at the start of the quarter, were drawn down to their lowest point for the last 5 years. Gas offers from the Iona gas storage were priced to reflect this scarcity. The Victorian price was capped at $40/GJ for the whole month following consistently high prices in June, and the uncapped Adelaide and Sydney short term trading markets (STTM) hit record high prices of $59.49 and $59.23/GJ respectively on 18 July.

Electricity prices also hit record levels in July in Victoria, South Australia and Tasmania, and near records in Queensland and NSW, with average monthly prices ranging from $327/MWh in Tasmania to $430/MWh in Queensland.

High electricity prices in July were driven by high winter demand, high fuel prices and energy constraints. Coal generator outages, local fuel supply problems, very high spot prices for coal and seasonally low wind and solar output over winter, combined to remove a significant share of low-cost generation from the market. As a result, the market was reliant on expensive gas and hydro generation to fill the gap at the same time as gas spot prices were soaring. Market participants shifted capacity to higher prices to cover costs or to conserve fuel or water supplies.

We report more fully on these drivers in our Q2 2022 quarterly published in September.

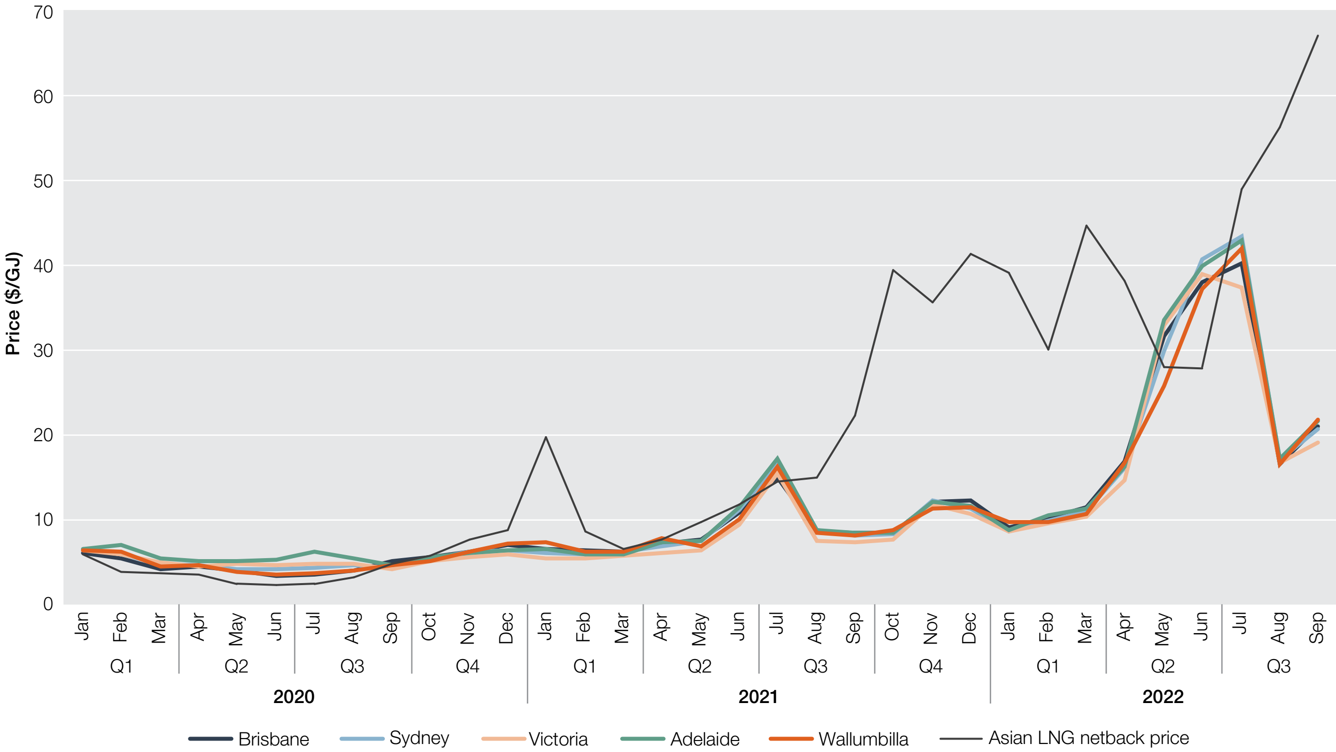
1 With the exception of August, monthly demand in Victoria and Sydney over Q2 and Q3 were at their highest levels since 2015, totalling 43.7 PJ in July.

1.3 Gas and electricity prices eased in August and September

Gas and electricity prices fell significantly in August and September as winter pressures eased (Figure 1.1).

Average gas prices on the east coast fell from around $40/GJ in July to around $17/GJ in August, well below international prices, before rebounding to around $20/GJ in September (Figure 1.3). Numerous factors contributed to these lower prices. Market demand for gas heating and demand for gas-powered generation in the NEM fell as the weather warmed. In addition, Iona gas storage levels improved as gas continued to flow south.

Figure 1.3 Domestic and international gas prices diverge



Source: AER analysis using DWGM, STTM and WGSH data, and ACCC netback price series.

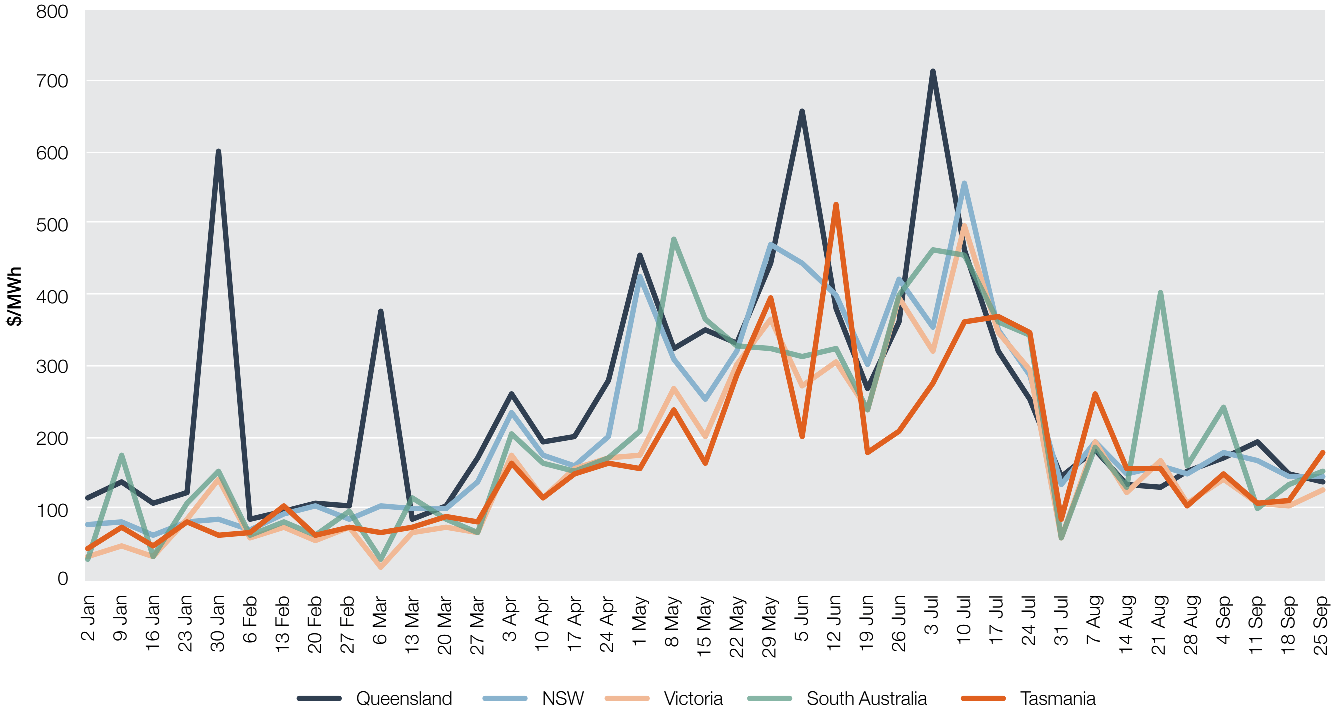
Note: The Wallumbilla price is the day-ahead price. The LNG netback price for gas delivery into October averaged $57.39/GJ for the quarter, exceeding the previous quarter's record high for the price series, with forward projections showing expected prices of around $60/GJ into 2023. The LNG netback price series for August ($48.91/GJ), September ($56.26/GJ) and October ($66.99/GJ) represent gas prices traded in the months prior (over the July to September period).

In the electricity market, weekly prices, which had been sitting between $200 to $400/MWh in July, fell to below $200/MWh in all regions, except for 2 price spikes in South Australia and one in Tasmania (Figure 1.4). Despite the significant fall in prices in August and September, prices were still high compared to a year earlier in every region. In Victoria, which was the cheapest region, prices averaged around $120/MWh in September 2022, compared to $33/MWh in September 2021.

Most of the drivers of the high June and July prices improved in August. Warmer weather saw a drop in demand and increased rooftop solar output (section 2.2), while at the same time, domestic gas prices fell (section 1.3), coal outages and fuel supply issues improved (section 5.4) and output from low cost wind and solar increased (section 5.1).

Prices in South Australia remained volatile over August and September due to outages for work on the Heywood interconnector from mid- August to mid-September. These outages limited imports from Victoria to 50 MW and impacted prices on days of low wind generation. South Australia became the most expensive region in the NEM in Q3 2022, slightly ahead of Queensland (Figure 1.2).

Figure 1.4 Average weekly electricity prices drop in August and September after peaking in July



Source: AER analysis using NEM data.

Note: Volume weighted average weekly wholesale electricity prices. Volume weighted average price is weighted against native demand in each region. The AER defines native demand as the sum of initial supply and total intermittent generation in a region. Weeks start on Sunday.

While high electricity prices were sustained across nearly every 30-minute interval of every day in June and July, in August, prices above $500/MWh all but disappeared in every region, except South Australia.

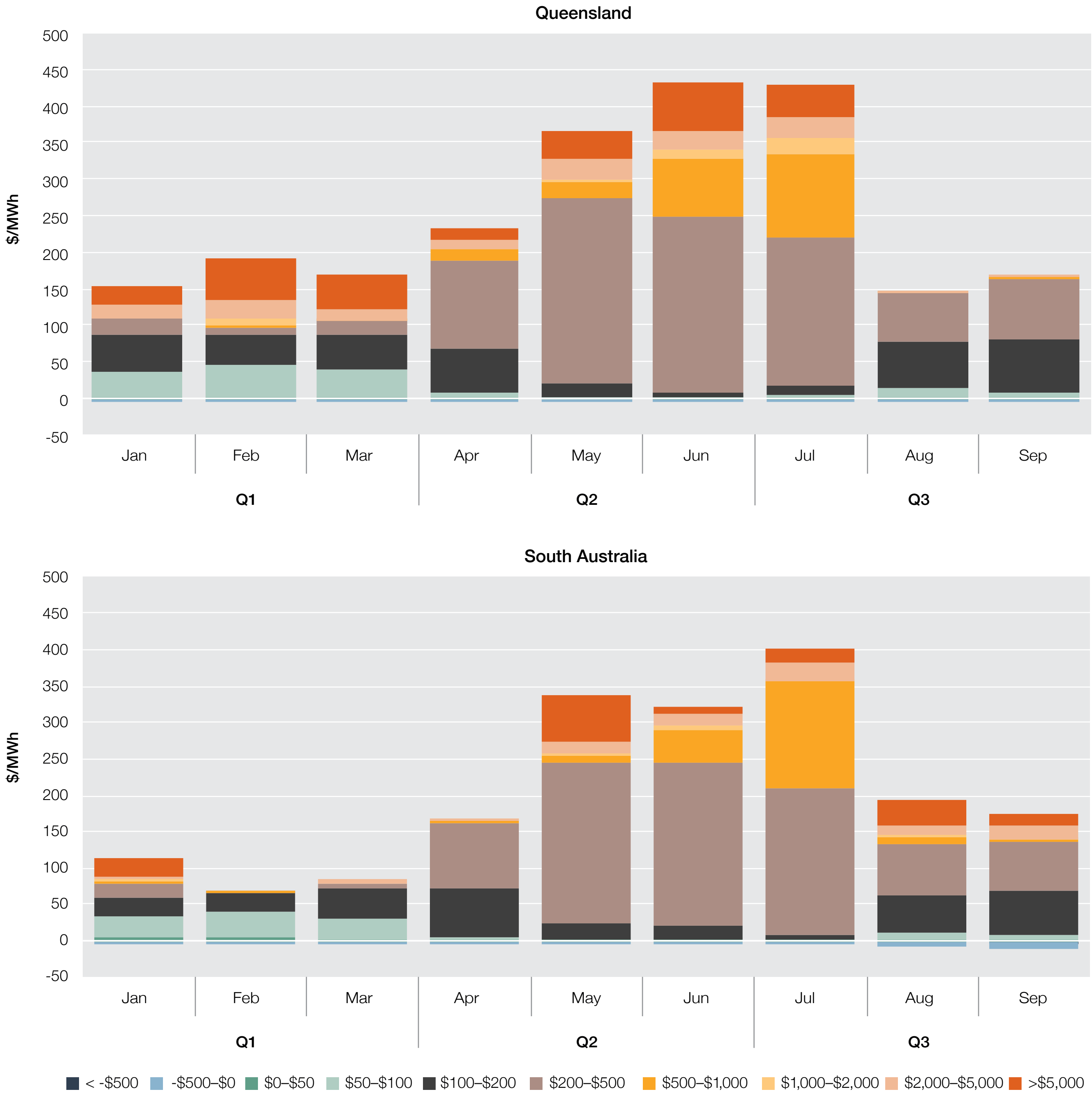
In Queensland for example, prices in the $200 to $500/MWh price band contributed $200/MWh or around half of the average monthly price of $430/MWh in July, and prices above $500/MWh contributed the other half (Figure 1.5). In contrast, prices below $200/MWh contributed very little to the average price. Queensland prices climbed above $5,000/MWh on 10 occasions in July. In August and September, however, there were very few prices above $500/MWh in any region except South Australia.

South Australia continued to experience prices spikes above $5,000/MWh in August and September (Figure 1.4). These occurred when combined events restricted access to low priced generation–including maintenance on the Heywood and Murraylink interconnectors limiting imports from Victoria, low wind generation and a planned outage at Pelican Point, the region's largest generator. These drivers were examined in more detail in an AER high price report.[2]

Most regions experienced increasing hours of negative prices as the quarter unfolded, due to lower demand and increased renewable output, but less than in Q3 2021. While South Australia recorded the most hours of negative prices in September (155 hours) than any other region, this only reduced the average monthly price by $10/MWh (Figure 1.5). Victoria had the second highest number of hours of negative prices in August and September, followed by Queensland then NSW.

2 AER, Prices above $5,000/MWh – 26 August and 8 September 2022 (South Australia), October 2022.

Figure 1.5 Contribution to average price by price band, monthly



Source: AER analysis using NEM data.

Note: Shows extent to which different spot prices within defined bands contributed to the volume weighted average wholesale prices in the region.

2. Demand a key driver of price outcomes

High demand was the key driver of high electricity and gas prices in July, and falling demand was the key driver of falling prices in August and September.

Average demand in the NEM was slightly higher in Q3 2022 than in both Q2 2022 and Q3 2021. Demand in each month of Q3 was higher in 2022 than the same month a year earlier, particularly in August (on average up 800 MW) and September (also up 800 MW). AEMO attributed this increase to the absence of COVID restrictions that were in place in 2021 and modest growth in rooftop solar output.[3]

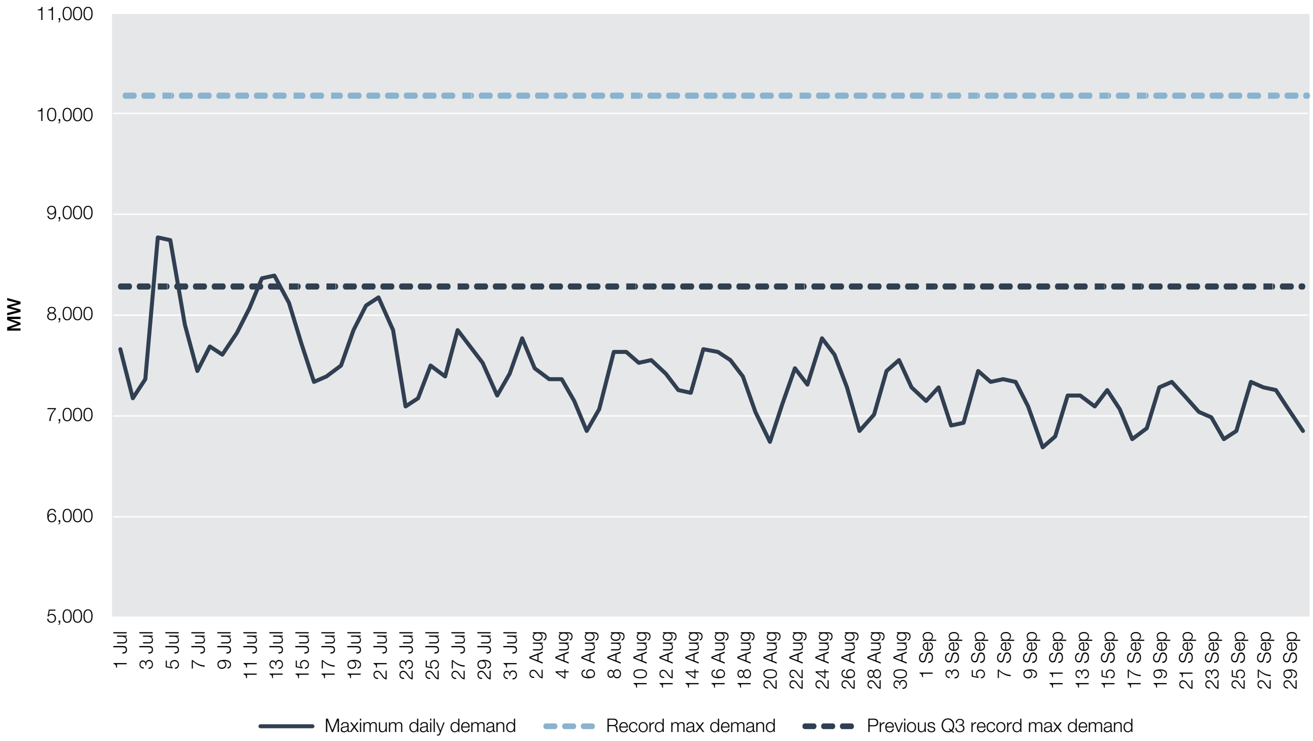
2.1 High demand for electricity, gas and gas-powered generation in July

Energy demand was high across all regions in early July because it was particularly cold.

In Queensland, many locations reported their coldest winter day on record.[4] Cold weather drove demand for electricity above the previous Q3 regional record on 2 different occasions (Figure 2.1). On both these days, Queensland was one of the coldest regions in the NEM, with temperatures in southern parts of the state dropping to zero or below. On 4 July Queensland beat its previous Q3 maximum demand record by 510 MW.

It was also cold across large parts of south-eastern Australia. Victoria saw the coldest start to winter since the 1940s and experienced cold nights and below average minimum temperatures. In Sydney, maximum temperatures in July were around 1 to 2 degrees below their seasonal average.[5] And South Australia had its coldest July since 2012.[6]

Figure 2.1 Queensland reached a new Q3 maximum daily demand record



Source: AER analysis using NEM data.

Note: Uses daily maximum native demand.

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3 AEMO, Quarterly energy dynamics Q3 2022, October 2022, pp. 3, 7.

4 Bureau of Meteorology, Seasonal climate summary for Queensland, 5 September 2022.

5 Bureau of Meteorology, Monthly climate summary for New South Wales, 3 August 2022.

6 Bureau of Meteorology, Monthly climate summary for South Australia, 2 August 2022.

In recent quarters, less gas-powered generation has been required to meet electricity demand due to an increase in lower cost renewable generation. However, that trend was reversed this winter. High demand for electricity, outages at several coal-fired power stations, and hydro constraints boosted the demand for gas to generate electricity.

Increased gas-powered generation was particularly prominent in NSW and Victoria with gas-powered generation use increasing significantly (up 49% in NSW and 122% in Victoria) in July 2022 compared to July 2021 (Figure 2.3). Gas generators were responsible for a significant increase in spot gas purchases, driven by the need to run their gas units at higher output.

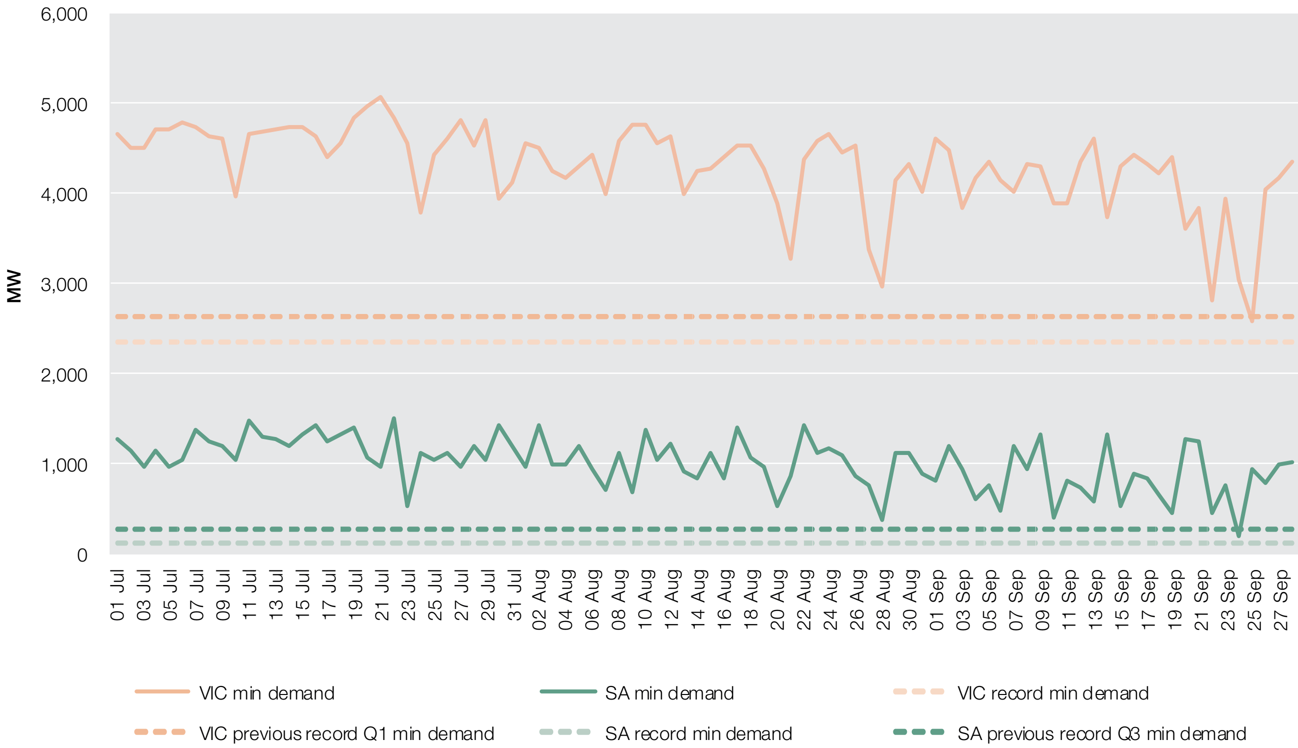
2.2 Demand fell in August and September

Reduced market demand in August and September eased pressure on domestic gas and electricity prices.

Demand for electricity fell through the quarter, as expected, with warmer weather and longer days. This was especially true in the middle of the day when rooftop solar output peaks. New installations of rooftop solar continue to reduce demand in times of high solar output and despite higher average demand in Q3 2022, demand in the middle of the day was lower than in Q2 2022 and Q3 2021. This led to new minimum daily demand records in the southern regions in the last week of the quarter.

Native demand in South Australia fell to just 197 MW on 24 September, below the previous minimum record of 265 MW set in September 2022. Minimum demand in Victoria fell to a new record low on 25 September. On the same day, AEMO reported a NEM-wide minimum operational demand record, almost 3% below the previous record set in October 2021, and that rooftop solar contributed 42% of total energy demand.[7]

Figure 2.2 South Australia and Victoria broke Q3 minimum demand records



Source: AER analysis using NEM data.

Note: Uses daily minimum native demand.

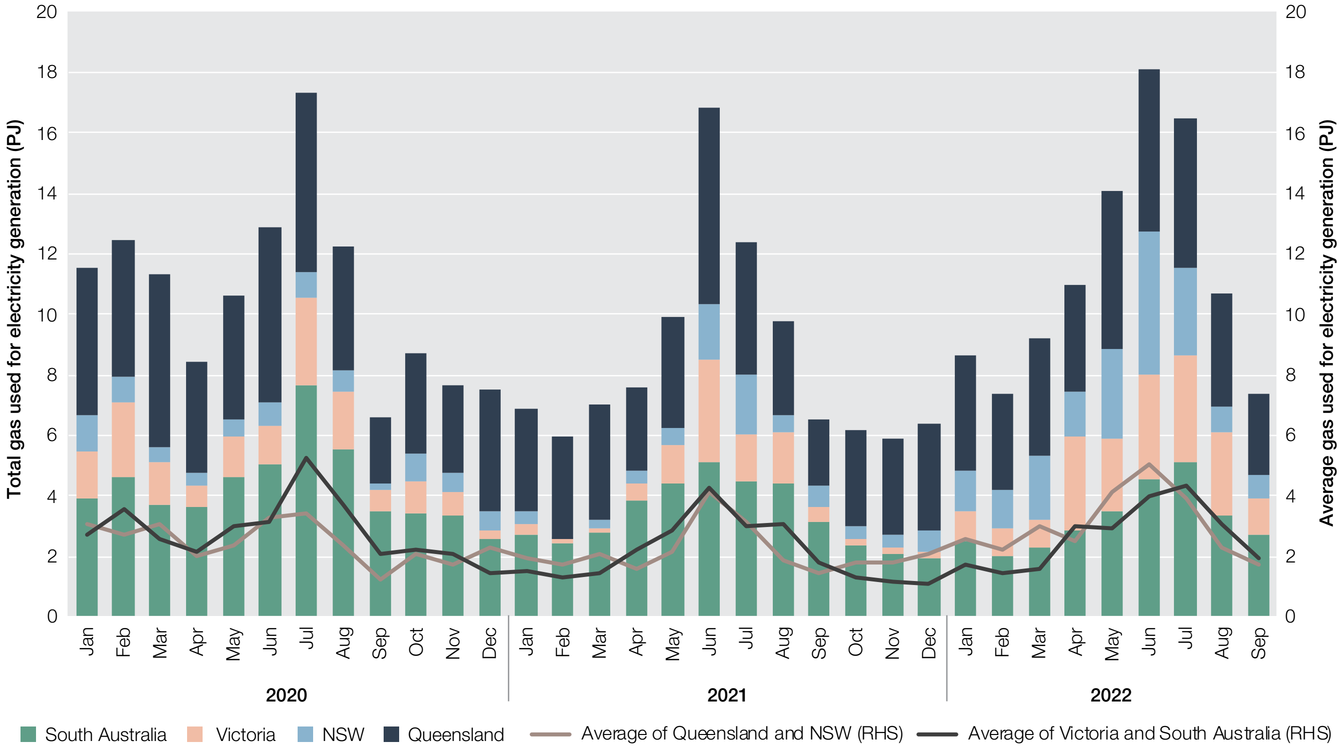
East coast gas market demand collectively fell by 5.3 PJ in August, largely driven by the Victorian market. Of the 4.5 PJ reduction in Victorian market demand compared to the previous quarter, 2.4 PJ was due to reduced gas-powered generation demand.[8] Demand for gas-powered generation was also down from the previous quarter in Queensland and NSW, falling significantly in August and again in September, reflecting lower demand for electricity (Figure 2.3).

7 AEMO, 26 September 2022.

8 The total reduction in gas powered generation demand in Victoria was 1.5 PJ including generation outside the Declared Transmission System (DTS). However, excluding the Bairnsdale and Mortlake power stations located outside the market, DTS GPG demand reduced from 6.6 PJ to 4.2 PJ.

While average gas-powered generation was lower in Q3 than in Q2 2022, in all regions except South Australia, the high demand in July meant that there was more gas used for electricity generation in Q3 2022 than in Q3 2021. This is despite the decreasing trend in gas-powered generation in recent years as gas-powered generation is being gradually displaced by renewables.

Figure 2.3 Less gas used for electricity generation in August and September



Source: AER analysis using NEM data.

Note: Gas use estimates are conversion of electricity generation output using average heat rates (GJ/MWh).

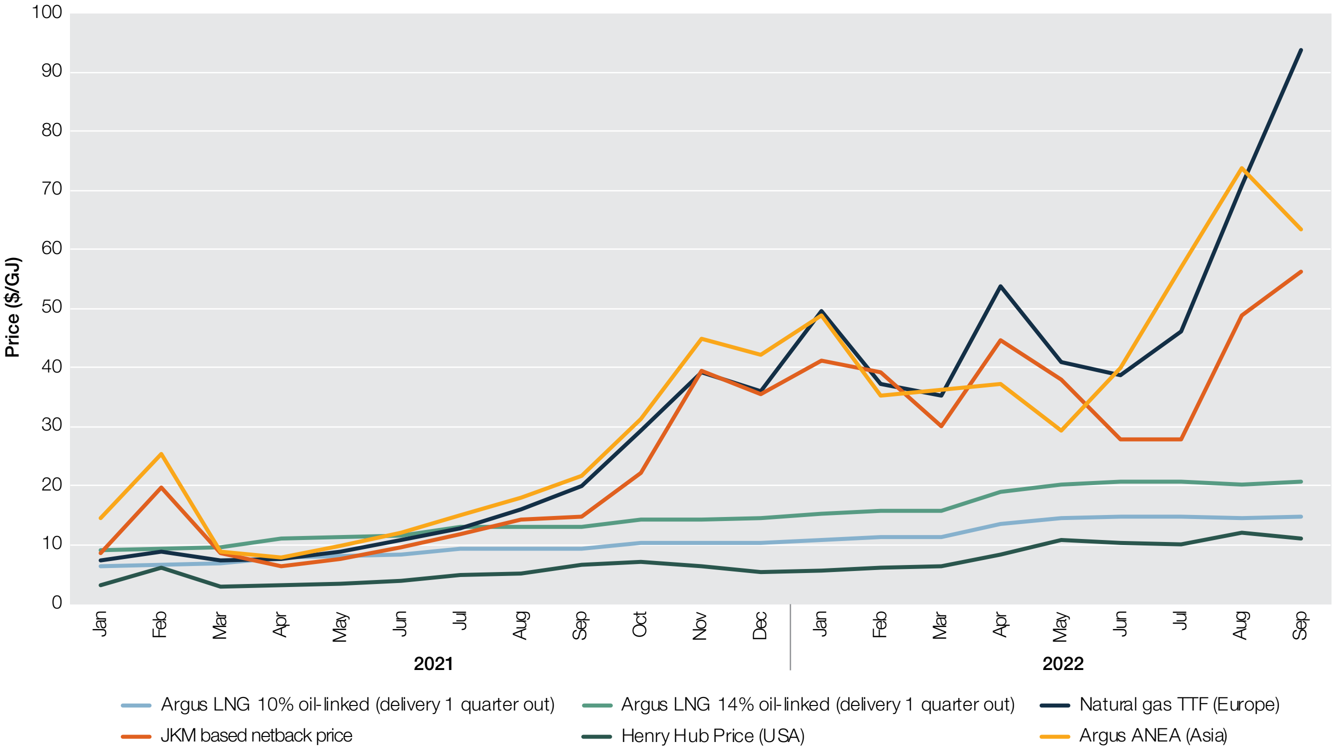
3. International fuel prices remain very high

International prices for gas, oil and thermal coal remained high in July, August and September. With sanctions placed on Russian gas, coal and oil, energy prices continued to climb as Europe and Asia sought alternative sources to build stockpiles ahead of the northern hemisphere winter.[9] While American international prices were lower than other markets, the Henry Hub price reached a record high for the month of August, averaging $12/GJ.

The Newcastle thermal coal price continued to rise, driven by high demand and tight international supply to an average of almost $700/tonne in September. (Figure 5.7). Very high gas prices and the fear of gas shortages have prompted some European countries to announce plans to reactivate coal power plants to support electricity generation.[10] While the Newcastle coal price dropped in October, the prices of energy commodities are expected to remain relatively high into the future.[11]

High international prices put upwards pressure on domestic fuel prices as exporters face stronger incentives to sell into international markets rather than supply domestically. While LNG exports levels for the July to September quarter were down compared to the high level of export trade in recent years, higher international prices for these commodities are expected to influence future gas prices, as these are often refenced in longer-term gas contract pricing. Coal-fired generators appear to have been less exposed to high coal spot prices in August and September than in July (section 5.3.2). Nevertheless, high international coal prices are likely to continue to put pressure on local coal supplies and prices.

Figure 3.1 International gas and Brent oil prices



Source: AER analysis using Argus Media data and Bloomberg data.

Note: The Argus LNG 14% and 10% oil linked contract prices are indicative of a 14% and 10% 3-month average Ice Brent crude futures slope.

The Argus Natural gas Tile Transfer Facility (TTF) price is a month-ahead-delivered-spot price calculated at the TTF in the Netherlands.

The Henry Hub price is the average of end of day natural gas spot prices traded on the Henry Hub – sourced from Bloomberg.

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9 While gas inventories in Europe were built up over the quarter (above 90%) as more supply was sourced from LNG imports, Russian gas supply via the Nordstream pipeline was cut off in September.

10 Germany reactivates coal-fired power plant to save gas, DW, 22 August 2022. Germany, Austria, France and the Netherlands announced plans to reactivate coal-fired power plants.

11 The Department of Industry, Science and Resources, Resources and Energy Quarterly, September 2022.

4. Drivers of lower domestic gas prices in August and September

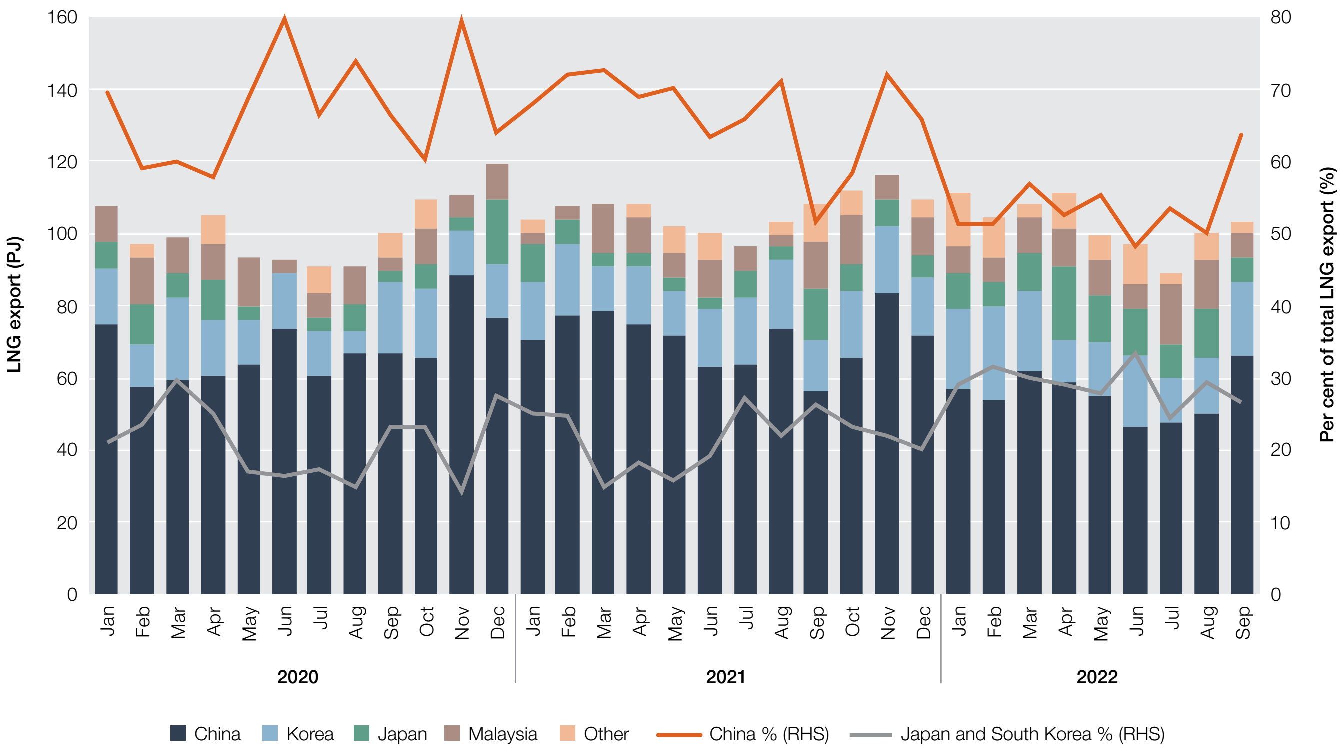
In addition to falling demand, other factors contributed to lower domestic gas prices in August and September 2022.

4.1 Lower LNG exports

Despite high international prices, LNG exports were down this quarter. LNG exports this quarter (293 PJ) were 16 PJ lower than last year's Q3 record (309 PJ) and just under 2019 which had the 2nd highest level of Q3 exports from Gladstone.

Gas exports were lower in July, with Queensland Curtis LNG impacted by an export train outage from mid-June until 18 July. On 19 July, AEMO convened a Gas Supply Guarantee conference for the domestic market in response to low gas storage supply in the south. Following this conference, LNG exporters significantly increased domestic sales.[12] Exports increased in August and September, however an Australia Pacific LNG (APLNG) full train outage from late July across August contributed to export flows being below flows for the same period last year (Figure 4.1).

Figure 4.1 LNG shipped from Gladstone Port by destination



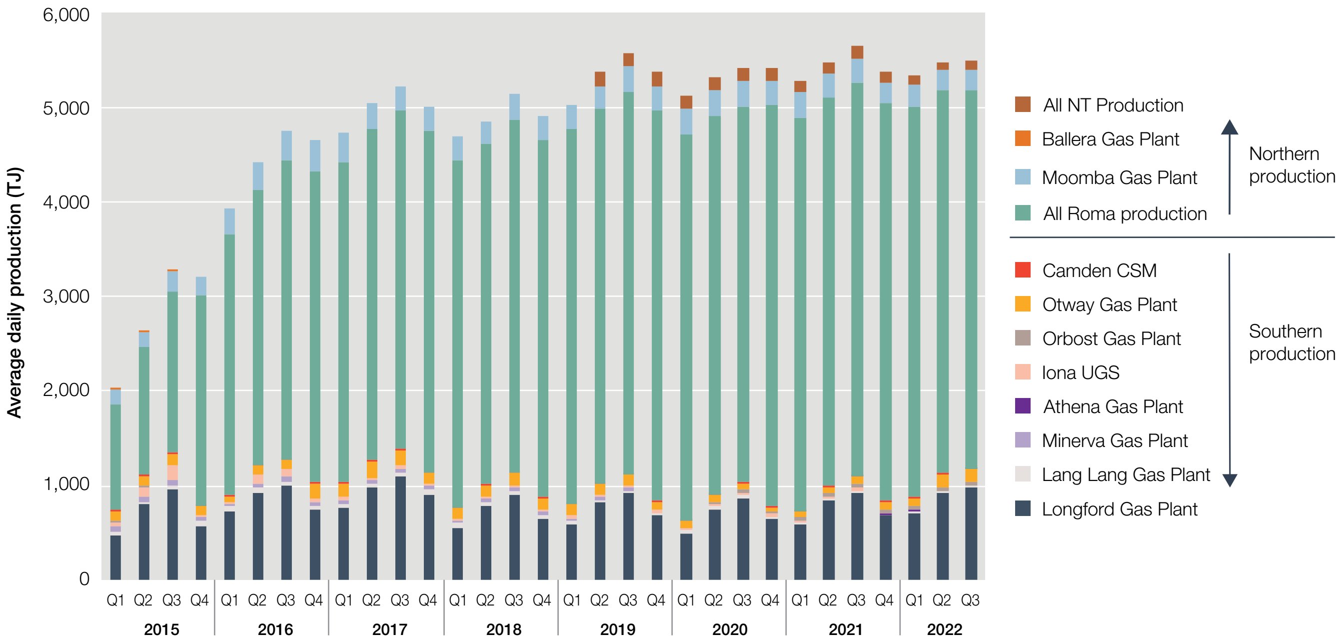
Source: AER analysis using Gladstone Port Corporation data.

4.2 Northern output increased as southern production fell

East coast gas production across in Q3 2022 remained at similar levels to Q2 as falling output from Longford in the south was offset by increased output from Roma in the north. Daily production from Longford, which was higher in July (1.26 PJ), fell in August (1.12 PJ) and September (1.14 PJ per day), whereas production at Roma, which was lower in July (3.98 PJ), increased in August (4.11 PJ) and September (4.09 PJ per day).

12 These trades are noted in the AER Gas Weekly covering the period.

Figure 4.2 East coast production (including Northern Territory)

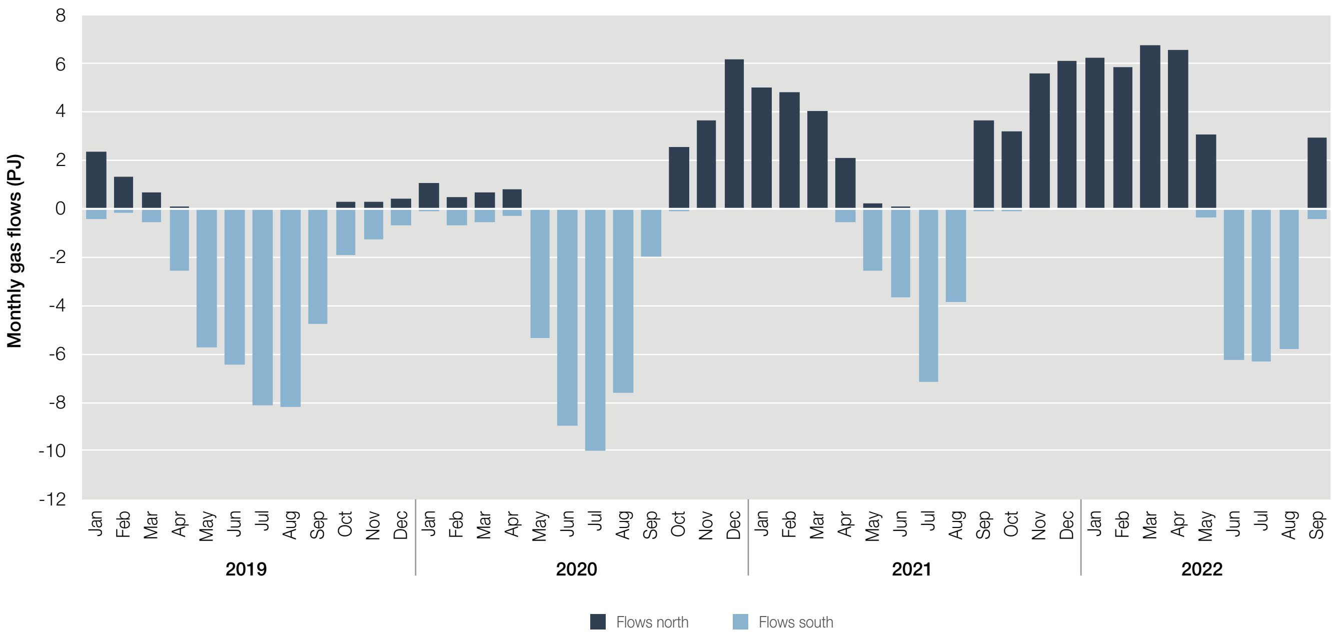


Source: AER analysis using Gas Bulletin Board data.

4.3 Gas flowed south

Queensland production remained strong during an APLNG full train outage over August, and gas flows towards southern markets only dropped slightly despite reduced market demand, continuing at levels comparable to those observed over June and July (Figure 4.3).

Figure 4.3 North-south gas flows



Source: AER analysis using the Gas Bulletin Board data.

Note: North–south flows depict net physical flows around Moomba – north or south.

5. Drivers of lower electricity prices in August and September

5.1 More capacity offered below $50/MWh in Q3 2022

Q3 2022 saw an improvement in supply-side constraints. Generators offered 1,100 MW more capacity priced below $50/MWh than in Q2. Black coal, hydro and renewable generators increased their low-priced offers. Wind offers increased by around 17% and black coal offers improved as units returned to service. Gas generators, however, offered less total capacity and less low-priced capacity despite falling gas prices.

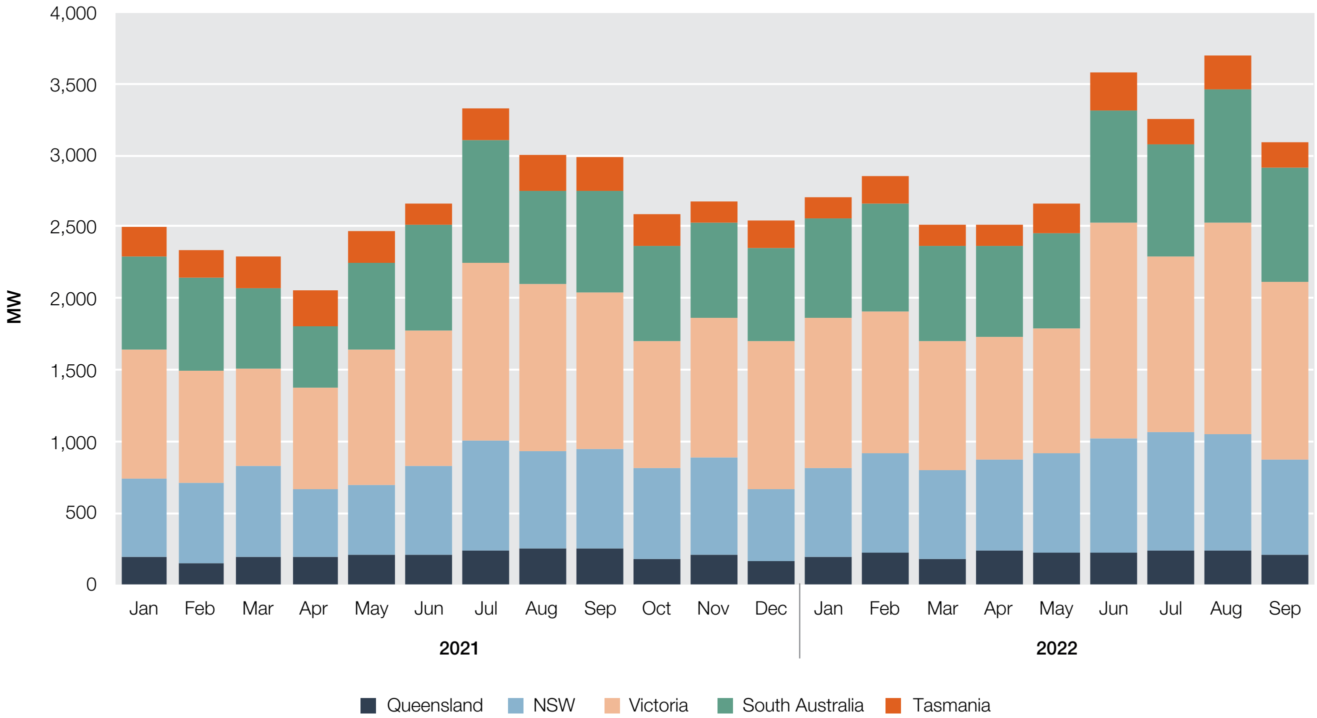
5.2 Solar and record wind displaced thermal generation

Low-cost wind and grid-scale solar generation increased in August and September and displaced expensive thermal generation.

Average monthly wind output ranged from 3 GW to 3.7 GW over the quarter. It was 15% higher in Q3 2022 than in Q2 due to windier conditions, and 8% higher than in Q3 2021, largely due to additional capacity installed over the year, particularly in Victoria (Stockyard Hill). Wind output set a NEM record on 4 August (typically the windiest month of the year) reaching over 7,300 MW. Higher year on year output in Victoria, South Australia and NSW was partly offset by falls in Queensland and Tasmania. At times over August, wind generation was able to supply more than 100% of South Australian demand and almost 70% of Victorian output.

Average monthly grid-scale solar output ranged from 1 GW to 1.3 GW over the quarter. It was 19% higher in Q3 2022 than in Q2 due to longer daylight hours, and 27% higher than in Q3 2021 due to additional capacity installed over the year in every mainland region but particularly in NSW.

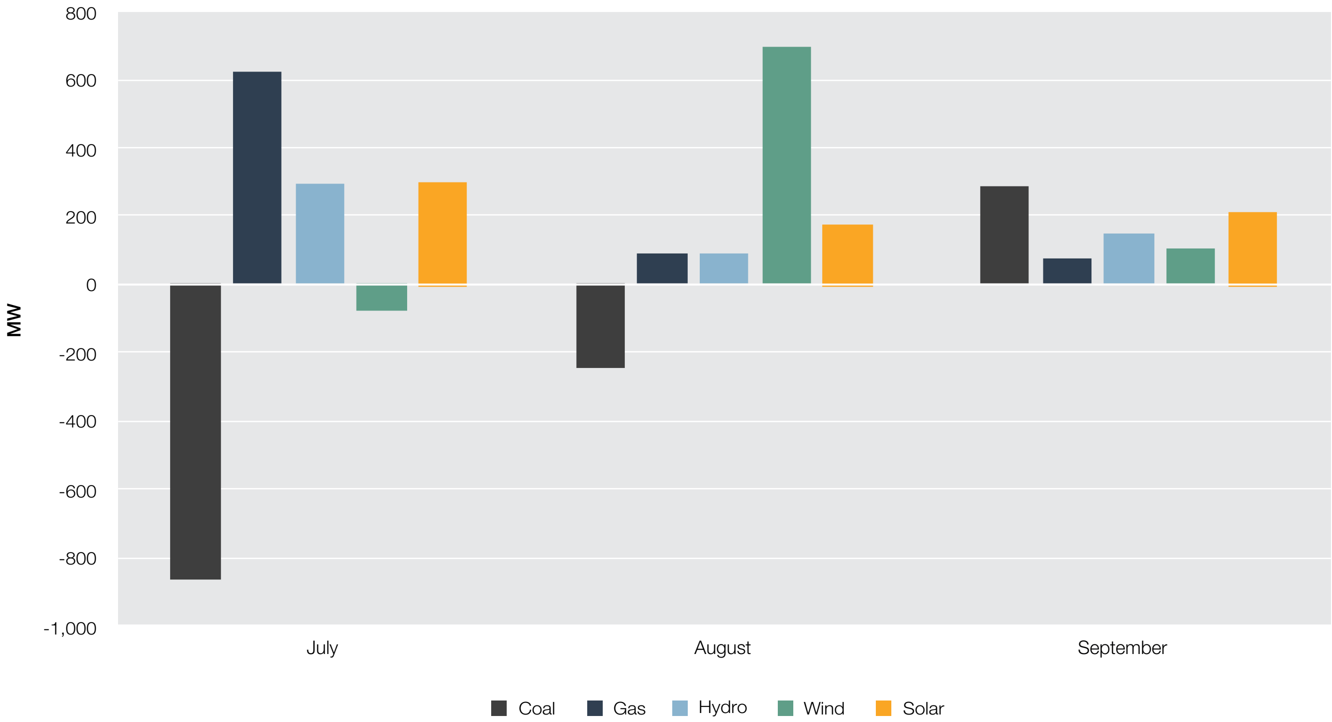
Figure 5.1 Record wind output in August



Source: AER analysis using NEM data.
Note: Average monthly wind output.

In July 2022 reduced black coal output meant more expensive gas and hydro generation was needed to meet demand at a time of soaring gas prices (Figure 5.2). In August, however, a notable increase in average wind output reduced that reliance. In September, an increase in average demand compared to a year earlier, was largely met by an increase in lower cost coal, solar and wind generation, as well as some additional hydro.

Figure 5.2 Increased lower cost generation displaces gas as the quarter proceeds, difference in monthly NEM output, 2022 vs 2021



Source: AER analysis using NEM data.

Note: Change in average monthly metered generation output by fuel type from July 2021 to July 2022 and so on. Solar generation includes large-scale generation only. Rooftop solar is not included as it affects demand not grid-supplied generation output.

5.3 Improved coal generating conditions

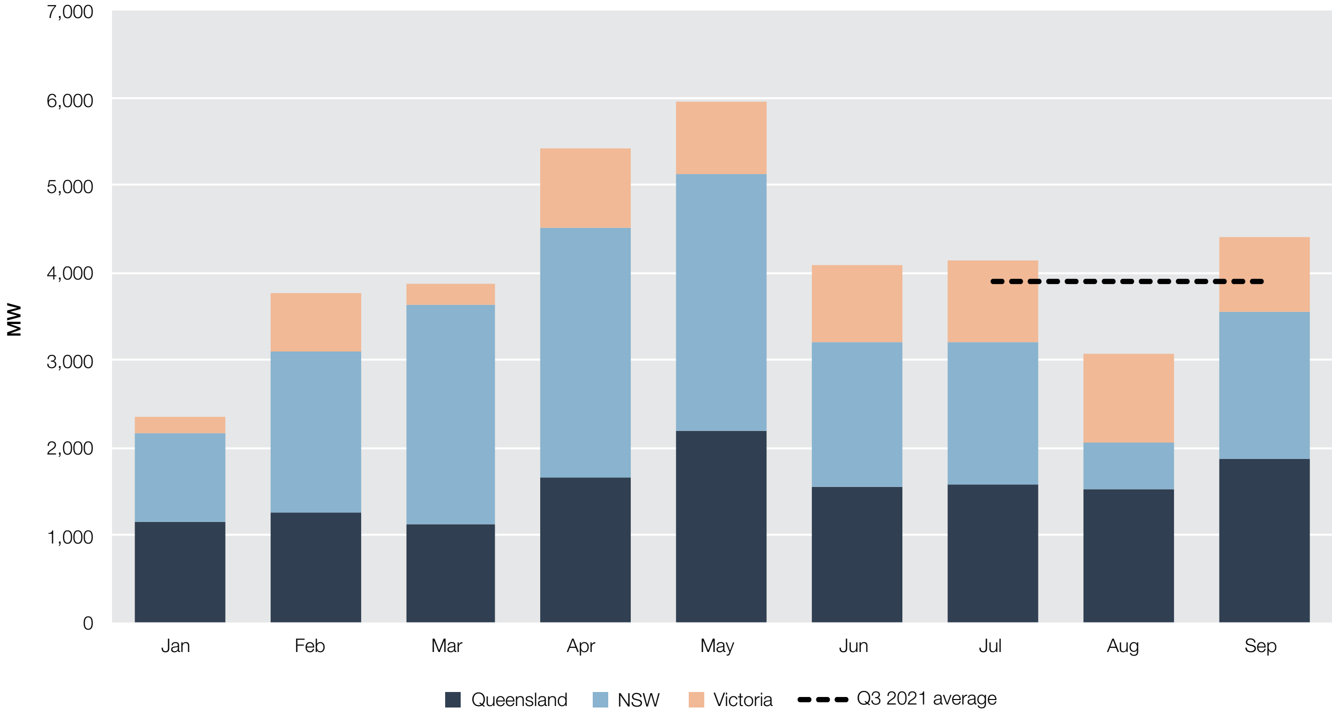
Average coal-fired output in Q3 2022 was lower than in Q3 2021, particularly in July, but was higher than in Q2.

In July 2022 coal output was 800 MW less than in July 2021, reflective of outages as well as fuel quality and availability concerns. As this reduction in output was made up by more expensive gas and hydro generation it increased prices. In August, coal output was down by only 200 MW compared to 2021, but this smaller reduction was more than offset by a large increase in wind output. In September, average coal output was 200 MW higher than the same month a year earlier.

5.3.1 Coal outages improved in August

While baseload outages were lower in Q3 2022 than in Q2, outages were higher in July 2022 than in any other July for at least the past 6 years. These outages which reduced baseload capacity by 4,000 MW had a significant impact on prices because demand was high (Figure 5.3). Outages reduced in August, especially in NSW where the only units off for a prolonged period were an Eraring and Liddell unit. Outages increased again in September, but these were mostly planned.

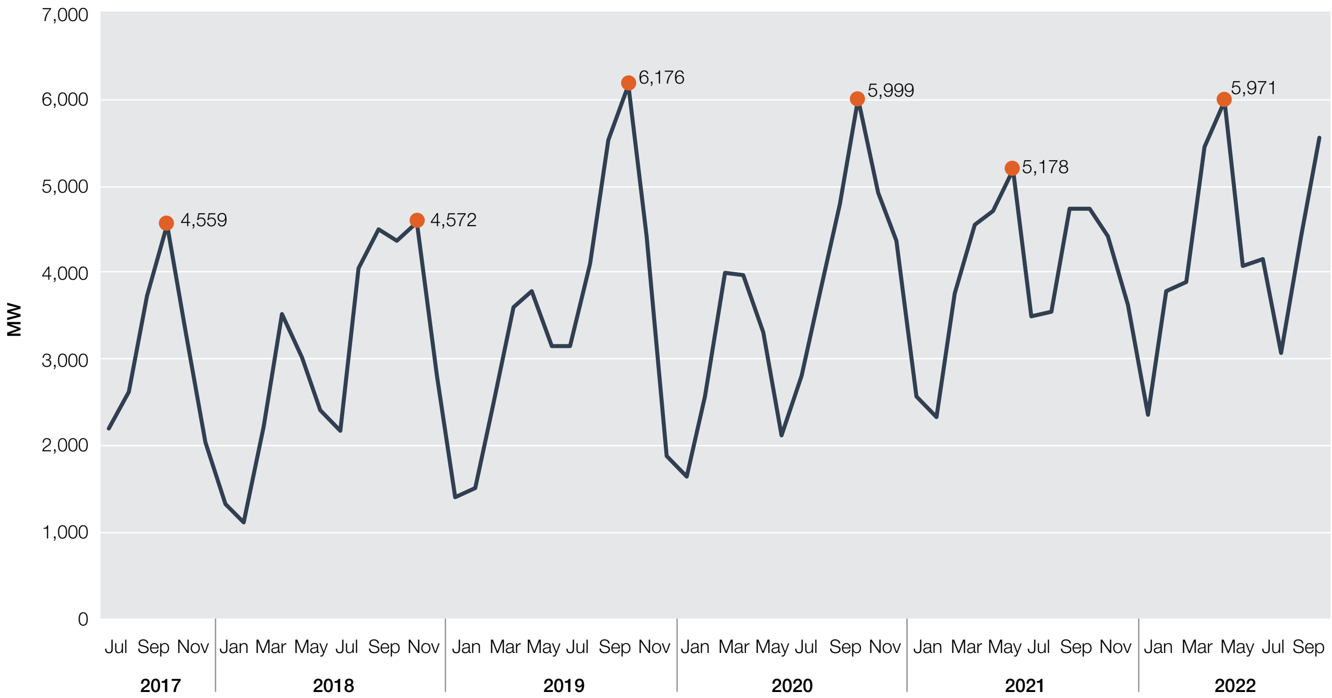
Figure 5.3 Monthly baseload outages by region



Source: AER analysis using NEM data.

Planned outages are generally scheduled for September and October when demand is low, in preparation for summer, or in April and May, in preparation for winter (Figure 5.4). For example, on 11 September around 3,600 MW (80%) of the 4,500 MW of black coal outages was planned. Unplanned outages in summer or winter when demand is high, such as those in July 2022, have a much larger impact on prices.

Figure 5.4 Baseload outages higher than usual in July then improve in August



Source: AER analysis using NEM data.

5.3.2 Black coal fuel constraints appear to have eased

In July, participants shifted black coal offers into higher price bands to:

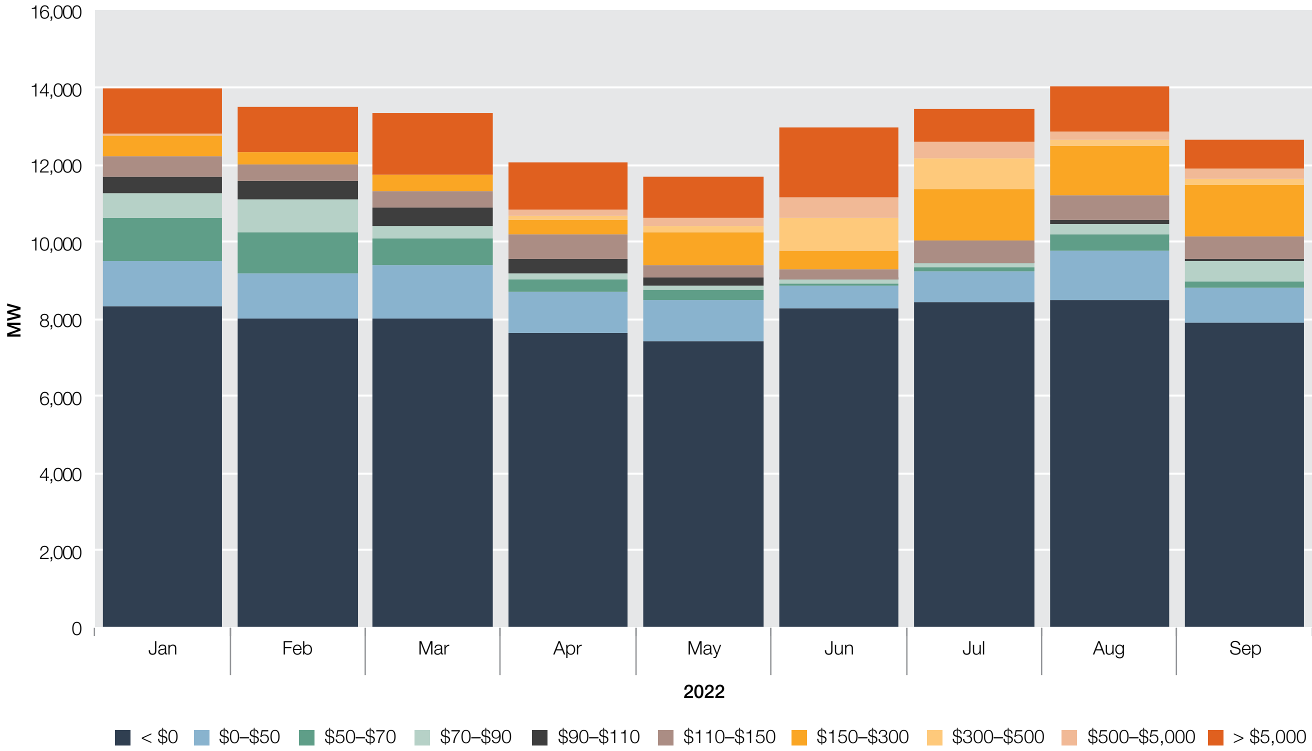
- cover rising fuel costs (if exposed to the coal spot price)
- manage diminishing stockpiles
- manage fuel constraints and fuel quality (issues with under-delivery of contracted coal, mine performance, rail access, and wet coal stockpiles).

Origin Energy, for example, faced problems obtaining coal for its Eraring power station from its supplier Centennial Coal and had to replace coal supply at higher prices while also cutting output.[13] Queensland coal fired power stations also suffered from floods, which caused coal delivery constraints by rail.

Improved offers indicate supply side conditions and concerns around fuel availability improved in August. Between July and August, black coal generators offered more capacity in total, more capacity priced below $50/MWh and shifted offers from above $5,000/MWh to below $300/MWh and below $150/MWh. Origin Energy, for example, reported it locked in new coal supply contracts to meet most of its needs for 2022–23 (while also warning the risk of coal under-delivery remains).

Black coal set the price more often in every region in August than in July and set much lower average prices (more than 50% lower). When black coal set the price in NSW and Queensland, for example, it set an average price of $137 to $138/MWh in August compared to $325 to $449/MWh in July (Figure 5.6). Black coal set the price less often in September at slightly elevated prices compared to August, but prices didn't increase because hydro set lower prices.

Figure 5.5 Black coal offers improve in August

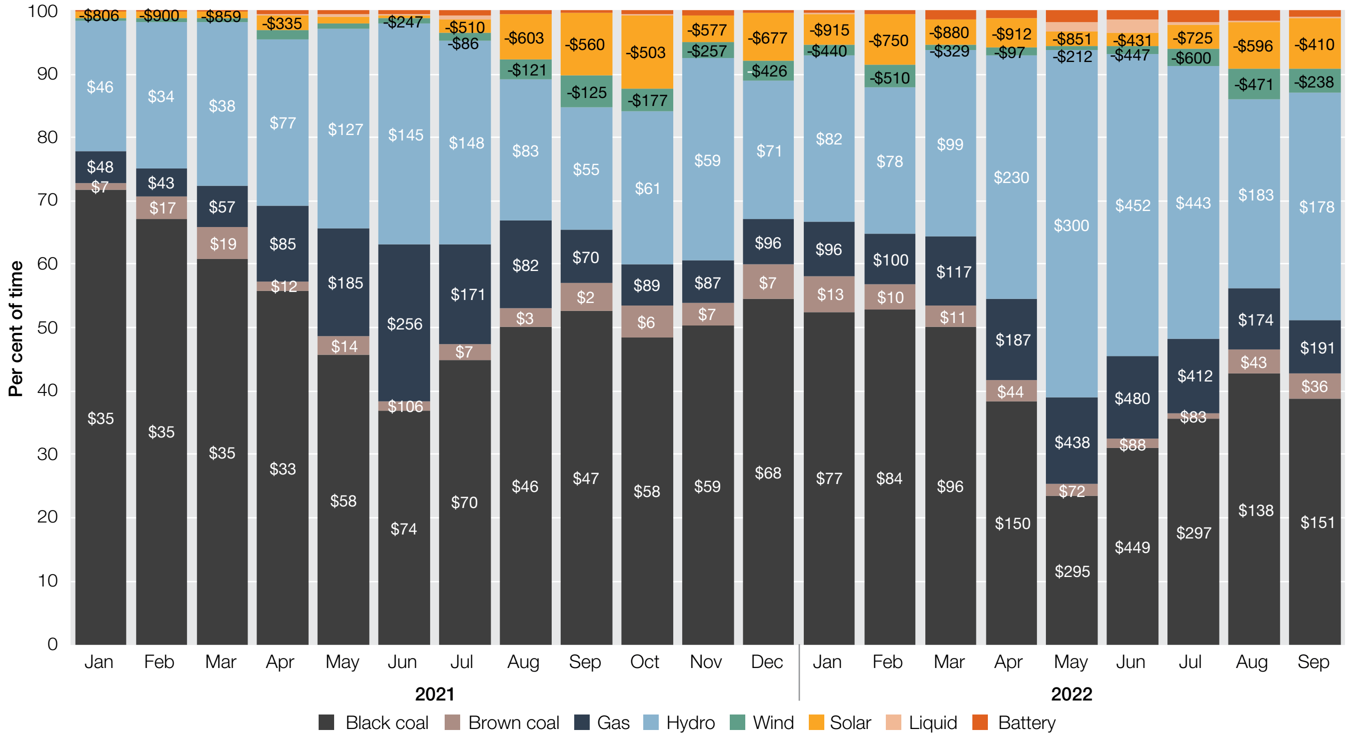


Source: AER analysis using NEM data.

Note: Average monthly offered capacity by NSW black coal generators within price bands.

13 Origin Energy, Earnings guidance, Quarterly update, June 2022.

Figure 5.6 NSW black coal sets the price more often in Q3 2023 and sets lower prices



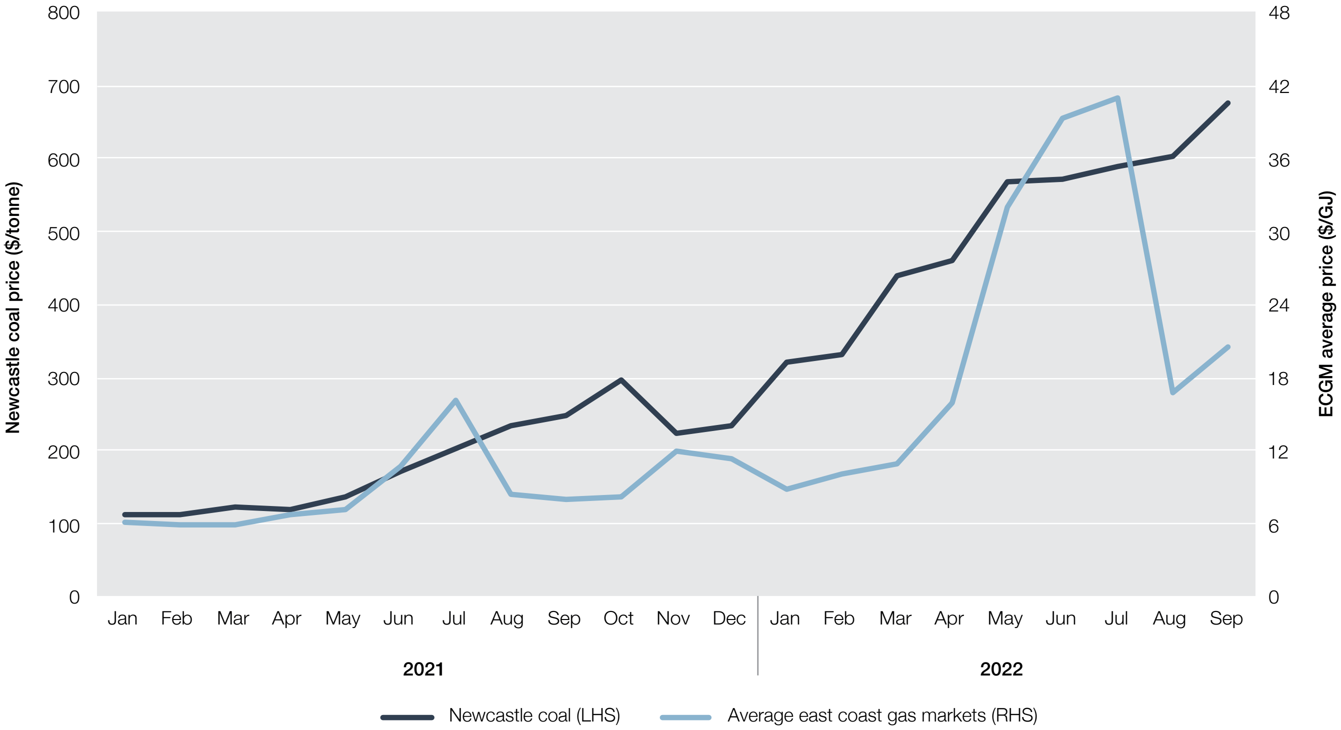
Source: AER analysis using NEM data.

Note: The height of each bar is the percent of time each fuel type sets the price. And the number within each bar is the average price set by that fuel type when it is marginal (i.e. setting the price). Data for Q2 2022 impacted by the 2-week market suspension in June.

5.4 Lower fuel costs for gas-powered generation and less gas generation needed

Average gas spot prices on the east coast fell from around $40/GJ in July to around $17/GJ in August (highlighted in section 1.3), before rebounding slightly in September (Figure 5.7).

Figure 5.7 Gas spot prices fell but Newcastle coal price continues to rise

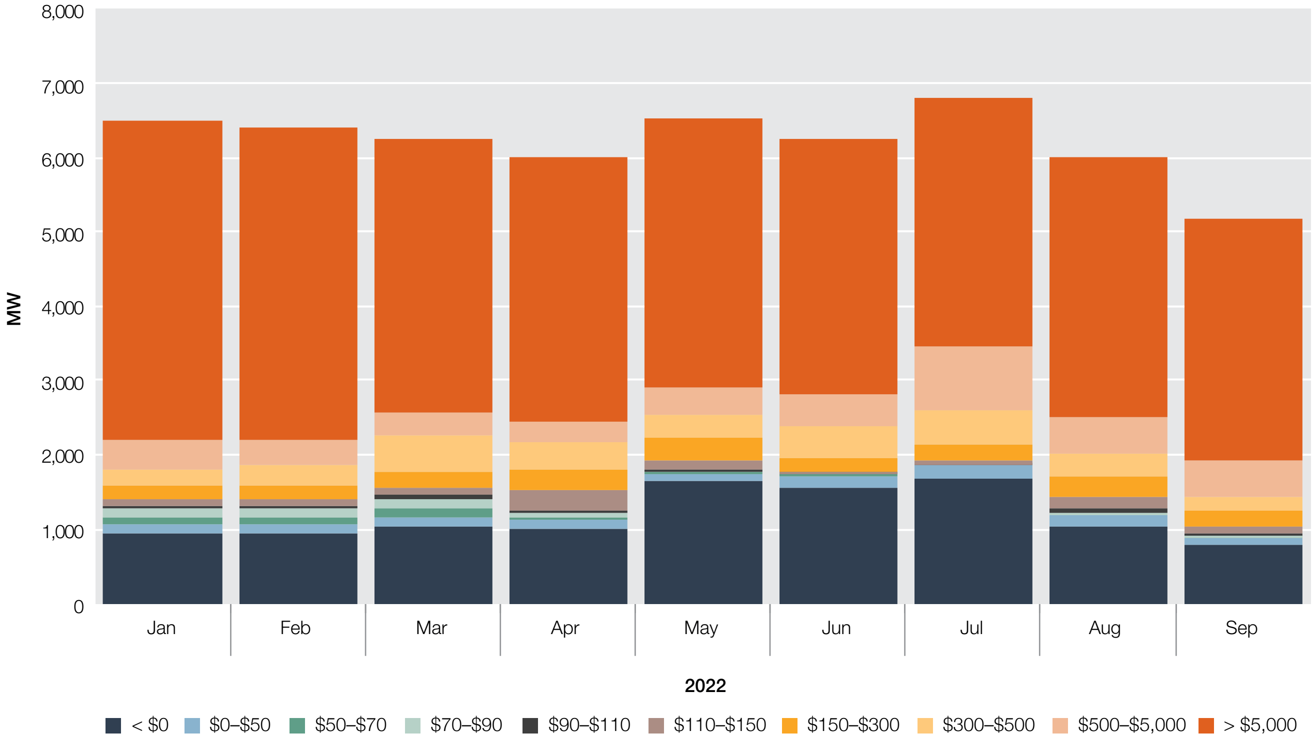


Source: GlobalCOAL and downstream gas market data (ECGM price averages DWGM and STTM daily prices).
Note: Data converted from $US to $AUD using the monthly average exchange rate for that month.

Despite lower gas prices, gas-powered generators offered less low-priced capacity in Q3 2022 than in Q2 in Queensland and NSW. Snowy Hydro rearranged its offers so more hydro was dispatched in place of gas (replacing Colongra gas output with lower priced Tumut 3 output). During Q2 2022, generation from Tumut 3 was constrained to avoid the risk of downstream flooding. In Queensland, less capacity was offered by Darling Downs, Yabulu and Braemar gas power stations.

Gas-powered generators set much lower prices in August than in July (around 60% lower) as the price of gas fell and less peaking gas was needed to meet falling demand (Figure 5.6). Queensland, NSW and Victorian gas plant, for example set an average price of $174 to $192/MWh in August compared to $412 to $508/MWh in July. South Australia was the exception where gas set an average price of $350/MWh in August. Gas also set the price less often in every region in August than in July as demand fell, black coal outages improved, and wind and solar output increased. Both these factors (setting the price less often and setting lower prices) contributed to lower electricity prices. Gas set the price less often again in September in every region, however it set the price at slightly elevated prices in Queensland, NSW and Victoria, following the same trend as black coal.

Figure 5.8 Gas-powered generators offer less low-priced capacity



Source: AER analysis using NEM data.

Note: Average monthly offered capacity by gas-powered generators in the NEM within price bands.

6. East coast gas storage levels improved after falling to record lows

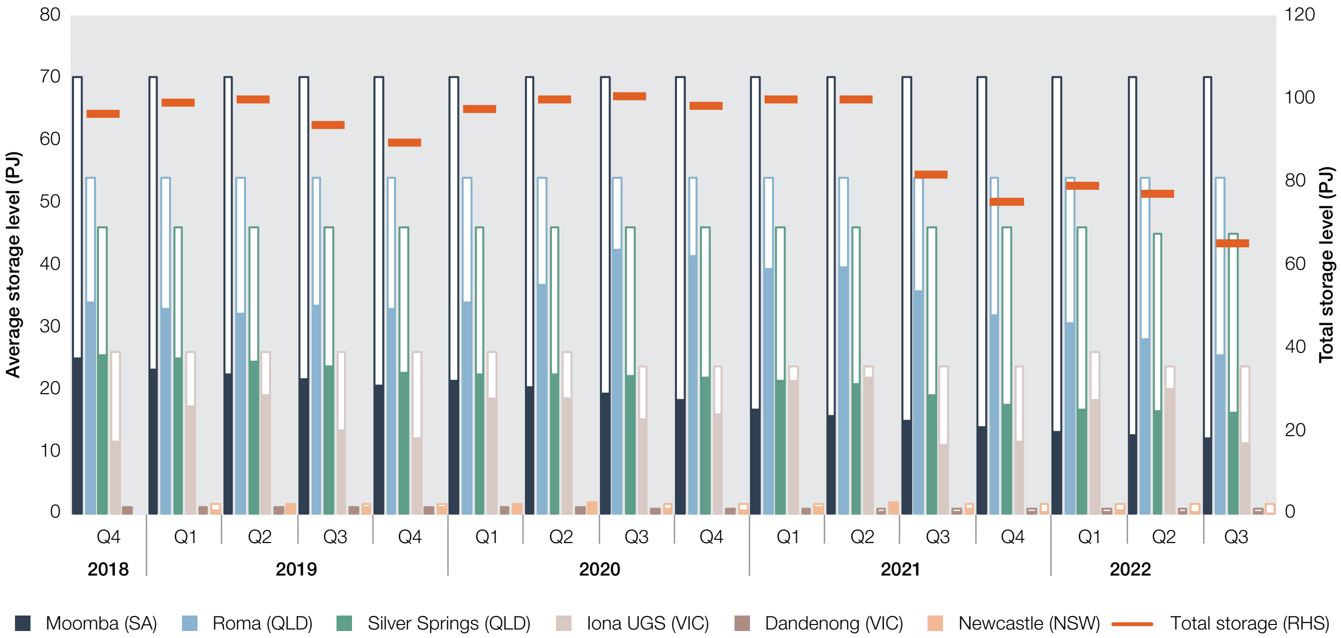
East coast storage levels dropped to their lowest point since reporting commenced on the Gas Bulletin Board (Figure 6.1). Due to the drop in pressure levels resulting from low storage inventories, east coast storage facilities have limited capacity to inject gas supply at times of higher demand, with most having gradually reduced nameplate capacity and projected daily supply capacity rates.

While Victoria's Iona gas storage facility has expanded to increase its storage and supply capabilities, the facility was heavily relied upon over the high demand winter periods in 2021 and 2022. As a result, storage levels in July reduced to critically low levels like the previous year, increasing the potential for storage inventories to fall below that required to physically supply the market over the quarter.

As such, AEMO's declared threat to system security following accelerated depletion rates over July remained in place alongside the activated gas supply guarantee until the end of September. AEMO will be actively monitoring refill rates at the facility against participant forecast ahead of winter next year.[14]

Storage levels at Iona increased from just over 10 PJ at the end of July to 12.5 PJ by the start of September, reducing the risk to system security before inventories decreased again in September.

Figure 6.1 East coast gas storage levels



Source: AER analysis using Gas Bulletin Board data.

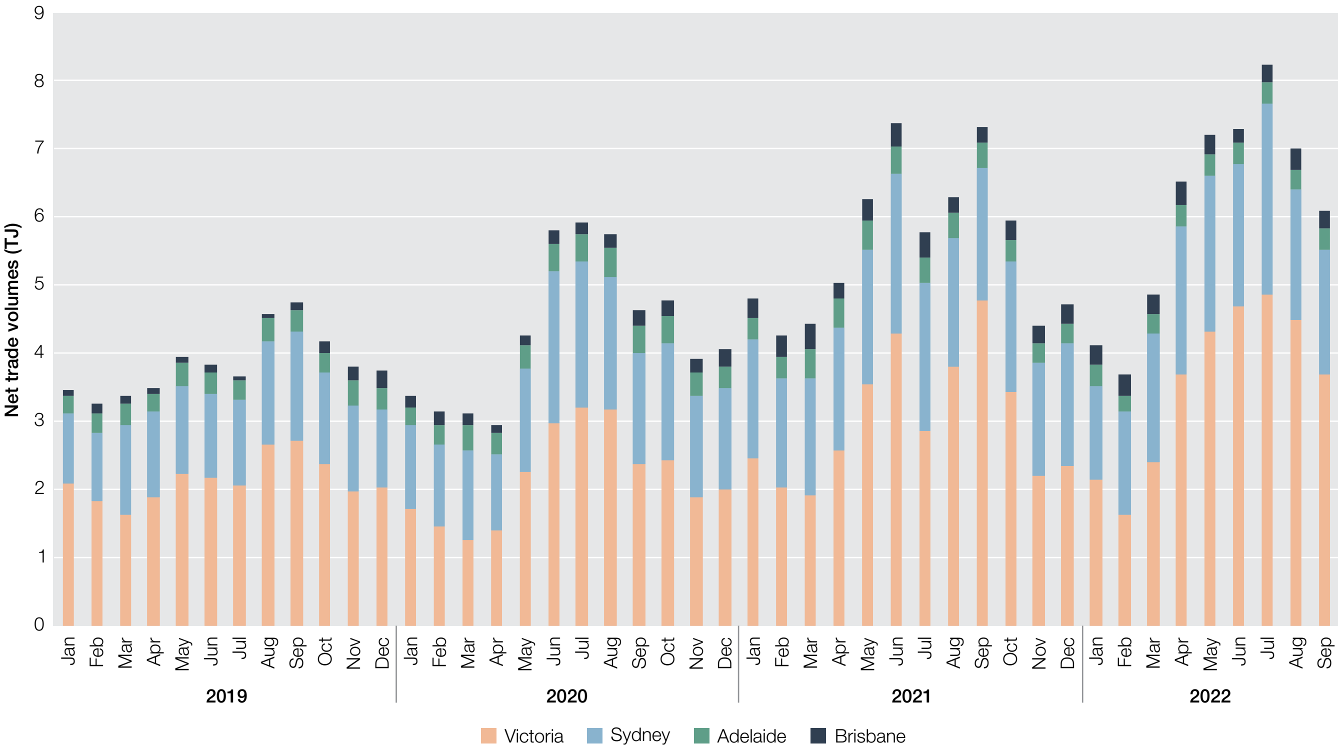
14 Iona has a planned 3 week outage during November and there is a 6 week period from mid-January to late-February when Longford production is forecast to be at low rates.

7. Gas market participation reached record levels despite high prices

Participation reached record levels in upstream and downstream gas markets in July and in Q3 2022, despite high prices.

Net trade in the downstream gas markets continued to increase following record volumes traded last quarter, reaching 21.3 PJ. This was primarily driven by the increased trade in Victoria rising by more than 330 TJ.[15] 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.[16] However, these monthly buy positions decreased below the previous quarter in August and September.[17]

Figure 7.1 Spot trade liquidity – net trade in east coast downstream markets



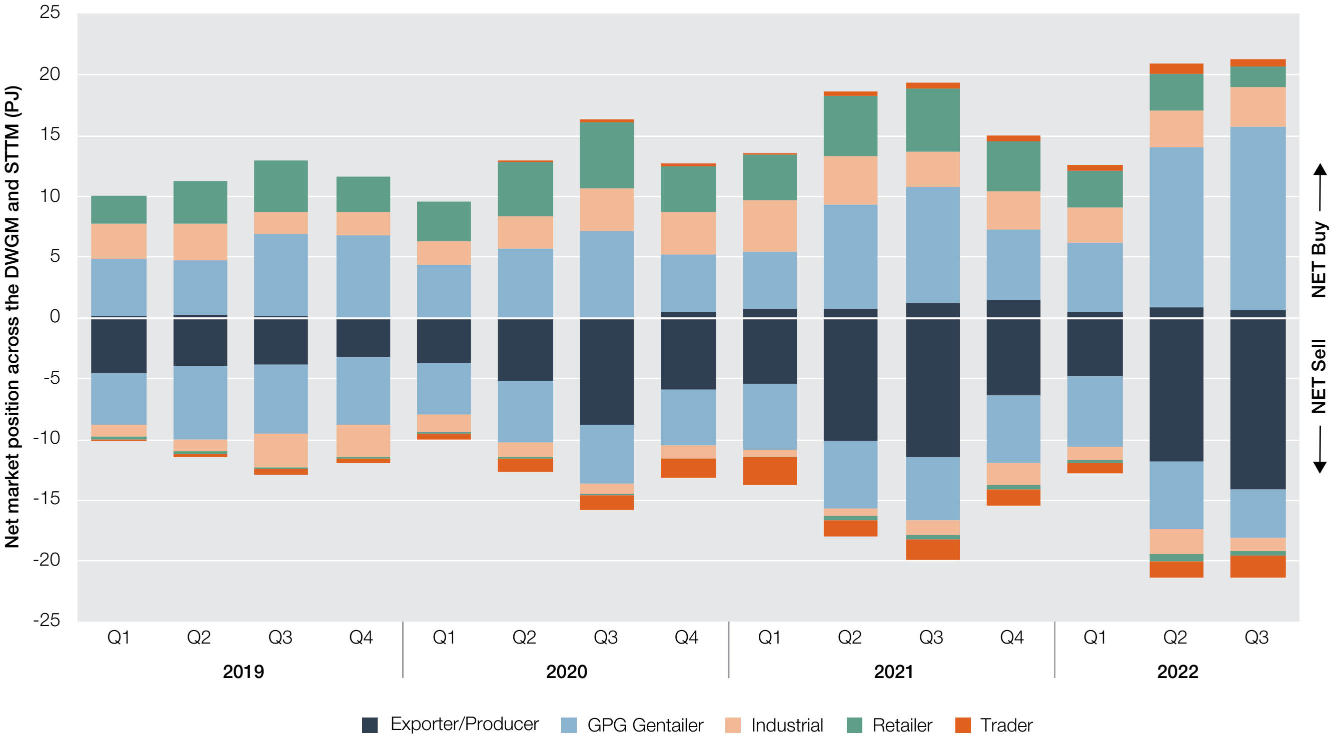
Source: AER analysis using DWGM and STTM data.

15 Trading levels in Adelaide were down from last quarter while Brisbane and Sydney saw small increases.

16 The monthly volume purchased across the downstream markets by GPG gentailers in July increased by almost 30% compared to average monthly purchases over the previous quarter.

17 GPG gentailer net purchases decreased from 6.2 PJ in July to around 4 PJ per month in August and September (just below the average quantities purchased across the previous quarter).

Figure 7.2 Net trade by participant

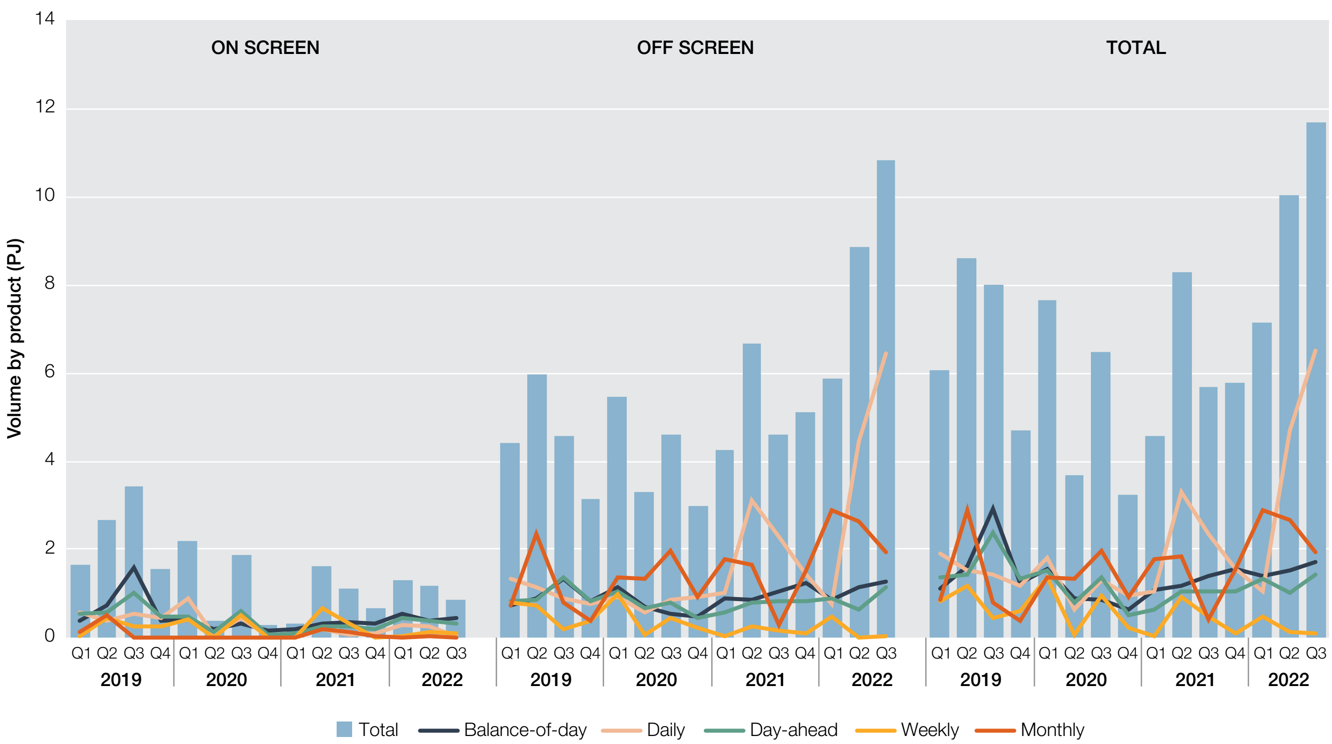


Source: AER analysis using DWGM and STTM data.

Note: Trade in the Victorian DWGM and Sydney, Adelaide and Brisbane STTMs has been estimated netting scheduled buy and sell quantities for each trading participant.

Traded quantities on the Gas Supply Hub (GSH) also exceeded last quarter's record level, driven by off-market participation and a significant quantity of strip products being traded. Strip products were introduced for the first time in September 2020, offering participants the ability to nominate multiple delivery days in a single trade. Strip products made up most daily product trades (off market) across Q2 and Q3 this year.

Figure 7.3 Gas supply hub – on-screen, off-screen and total trade by product

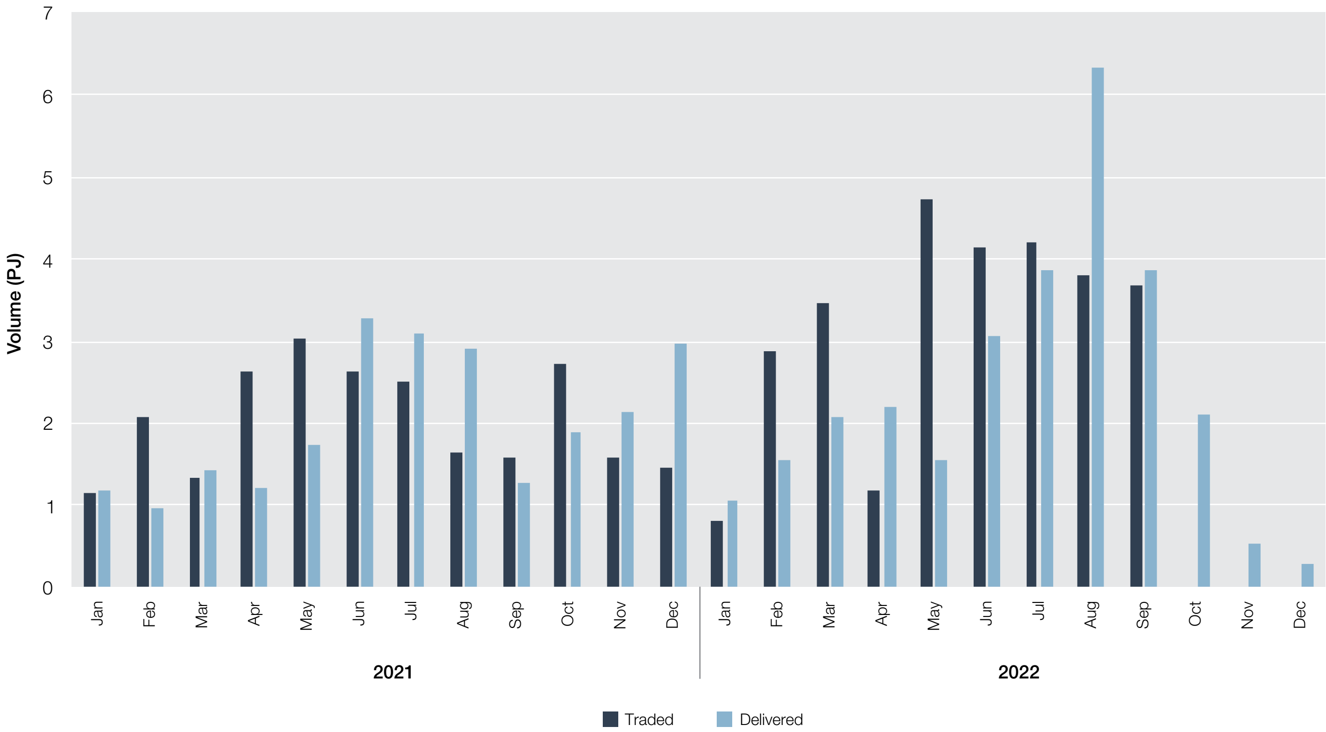


Source: AER analysis using Gas Supply Hub trades data.

Note: Volumes displayed are traded quantities.

Record deliveries also occurred across each month during the quarter, with deliveries over August of just over 6 PJ, surpassing the previous monthly record by 2.3 PJ.

Figure 7.4 Gas supply hub – traded and delivered quantities



Source: AER analysis using Gas Supply Hub trades data.

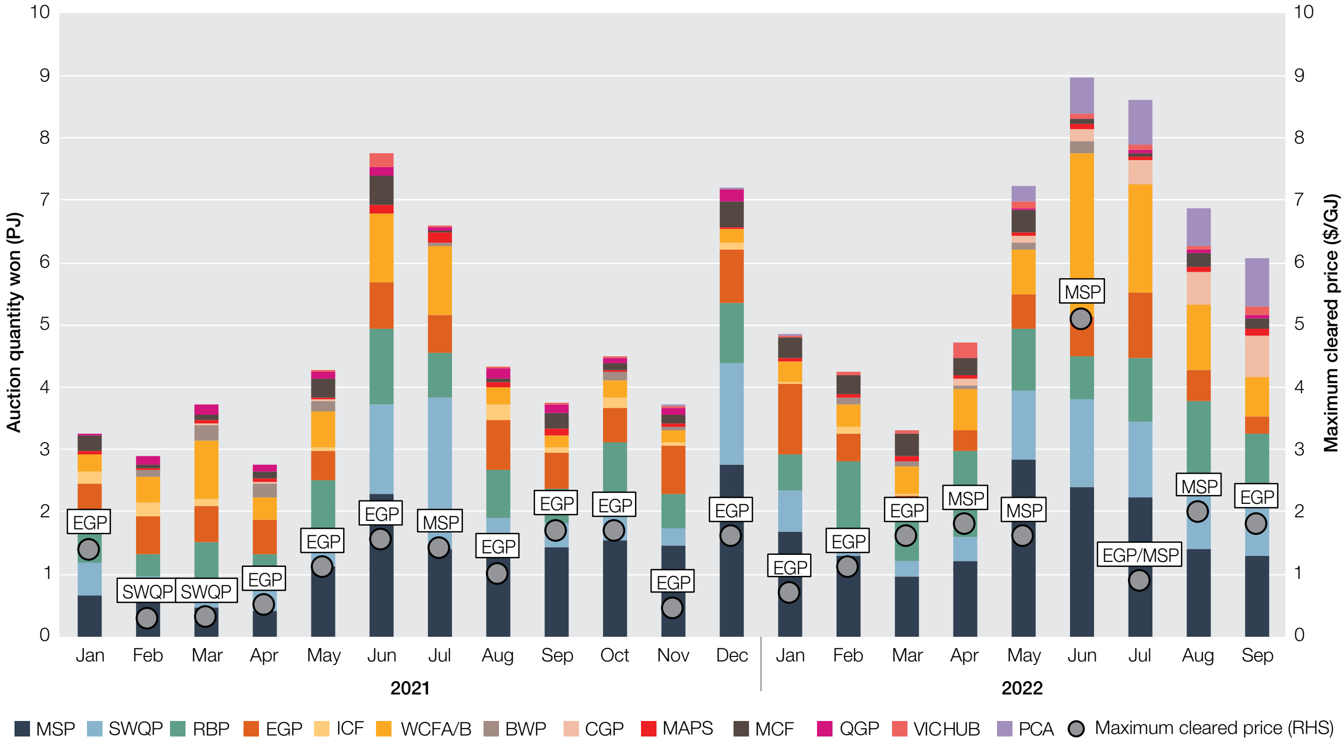
Note: Delivered quantities shown for trades that occurred up to 30 September 2022.

To assist in meeting their short-term transportation requirements, market participants continued sourcing significant quantities of secondary capacity through the Day Ahead Auction this quarter. Figure 7.5 shows auction quantities traded surpassed last quarter's record high, exceeding 20 PJ of capacity won. Following significant increases last quarter, trades on the popular Moomba to Sydney Pipeline (MSP) route and Wallumbilla compression facilities (WCFA/B) reduced, while trade on the South West Queensland Pipeline (SWQP) increased further.[18] Trade on the Roma to Brisbane Pipeline (RBP) also increase slightly from the previous quarter, reaching a record 3.4 PJ over Q3. There were also significant increases this quarter in capacity procured on the Eastern Gas Pipeline (EGP), Carpentaria Gas Pipeline (CGP), and the Port Campbell to Adelaide Pipeline (PCA).[19]

18 These facilities and pipelines are commonly used to bring gas south using secondary capacity as they have been close to fully contracted.

19 Capacity procured on the Carpentaria Gas Pipeline (CGP, 1.6 PJ) and Port Campbell to Adelaide Pipeline (PCA, 2.1 PJ) were the highest quarterly quantities won on the auction for those facilities to-date.

Figure 7.5 Pipeline capacity won on the Day Ahead Auction



Source: AER analysis using Day Ahead Auction data.

The maximum clearing price reduced markedly from last quarter's record high of $5.10/GJ set on the MSP in June, falling to $0.89/GJ in July (EGP/MSP) and not exceeding $2/GJ over August and September. However, average clearing prices remained at or close to zero across most facilities with the EGP and MSP being the main exceptions.[20]

Over the past two quarters, record auction capacity was won primarily by retailers, traders and industrial participants, with the majority of that capacity (just over 70%) obtained on the CGP, SWQP and MSP. While overall auction demand reduced from Q2 into Q3, more auction capacity became available across Q3 coming out of the winter period.[21] This capacity was concentrated around auction routes bringing gas south. On the MSP, 70% of capacity was won on routes south from Moomba for delivery into Culcairn. On the SWQP, the predominant direction of capacity won also remained on southern routes at close to 90% over Q3. In contrast to this, record quantities won on the CGP saw 83% of the 1567 TJ of capacity cleared to move gas north to Mt Isa over the quarter to offset supply disruptions from the Northern Territory.[22]

20 Average clearing prices were highest on the Eastern Gas Pipeline (EGP, $0.22/GJ) and Moomba to Sydney Pipeline (MSP, $0.14/GJ), while average prices on the Roma to Brisbane Pipeline (RBP) and South West Queensland Pipeline (SWQP) were under $0.04/GJ.

21 The total cleared and surplus demand levels reached 30 PJ in Q2, of which 20.9 PJ was cleared. This eased somewhat in Q3 with 26.9 PJ of capacity available, of which 21.6 PJ was cleared.

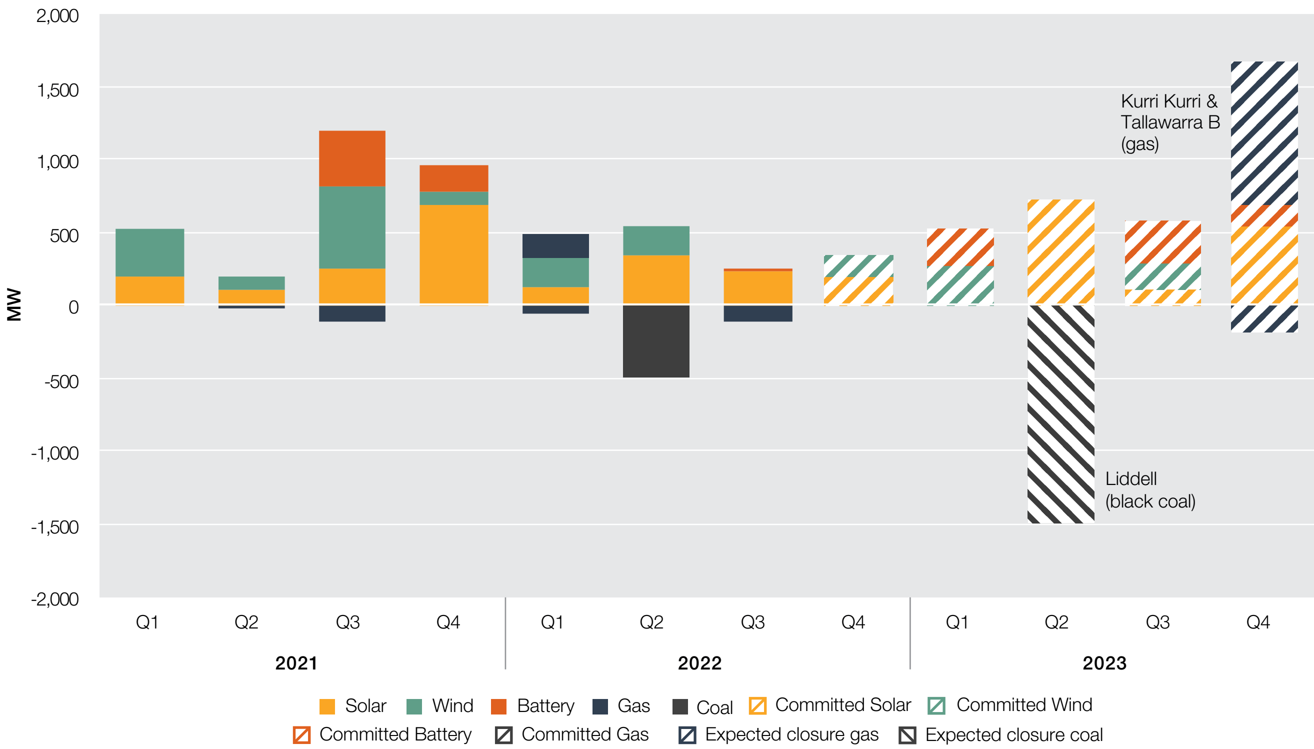
22 To ensure this capacity was secured, bids priced above $1/GJ were placed on the CGP for the first time over September.

8. New entry slows in the NEM

New generating and storage capacity in Q3 2022 was limited to 2 solar farms and a small grid-scale battery totalling around 250 MW. In September 2022, the last unit of Torrens Island (120 MW), a gas power station in South Australia, closed.

New capacity has slowed in 2022 and is expected to have the lowest volume of new entry in 5 years. 1,600 MW of new capacity is expected to enter by the end of the year while 670 MW exited. Looking forward, anticipated new entry in 2023 is not very high, especially if the planned completion of Kurri Kurri and Tallawarra B gas power stations are delayed. While at least 6 new batteries (totalling 700 MW) are anticipated next year, bringing system strength, solar-soaking and firming capacity, the last 3 units (1,500 MW) of the Liddell black coal power station will close in April, and Osborne gas power station (180MW) is expected to close in December 2023. It is important to bear in mind that the capacity factor of Liddell is many times that of new wind and solar and as such, its closure has impacted forward prices in NSW (section 9.1).

Figure 8.1 New entry slow in 2022 as some thermal generation exits



Source: AER analysis using NEM data.

Note: New entry is recorded using registered capacity of scheduled and semi-scheduled generators, except for solar. Solar new entry is recorded using maximum capacity (from this quarter onwards) because it is often lower than registered capacity. Hashed areas reflect committed new entry and planned generator retirements according to the classification in AEMO Generator Information. The new entry date is taken as the first day the station produces energy. Closures are denoted below the line. Solar is large scale solar and does not include rooftop solar. Start dates for Tallawarra B in October 2023 and Kurri Kurri in December 2023 based on information in AEMO's 2022 Electricity statement of opportunities.

9. Forward prices expected to remain high

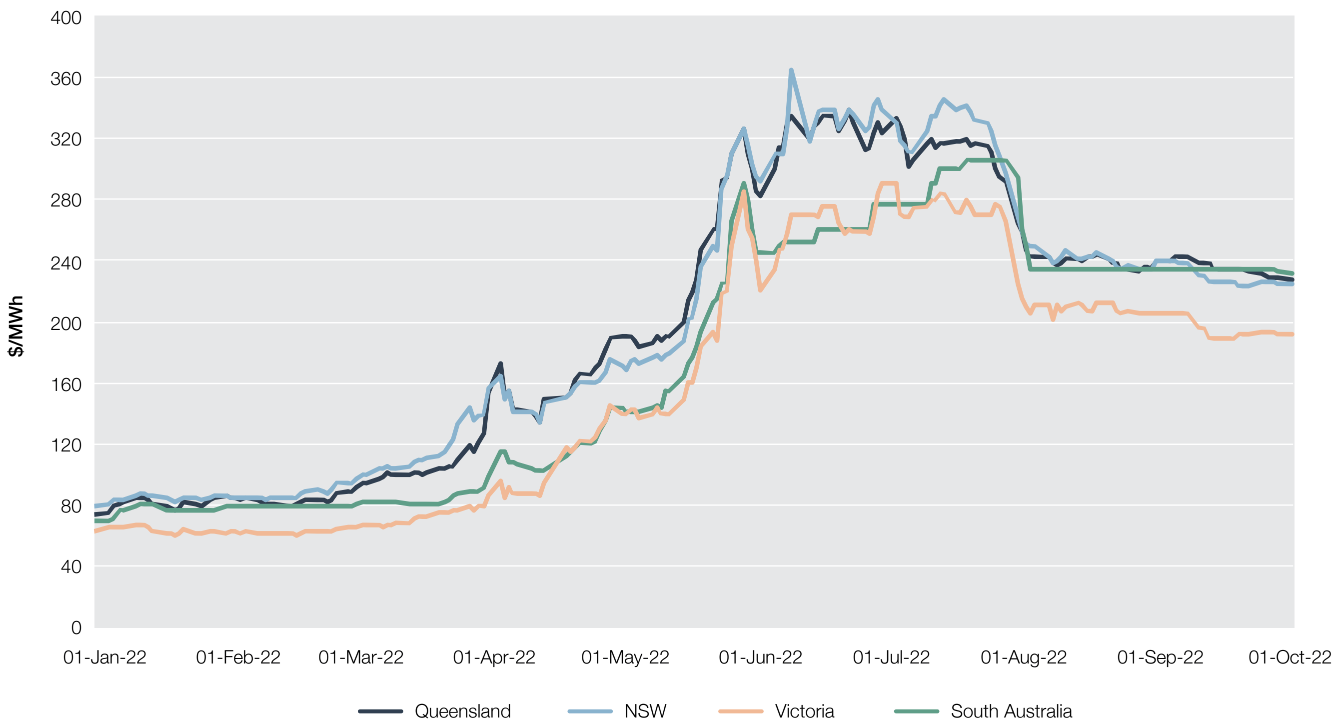
9.1 Electricity ASX futures set price records in all regions

9.1.1 Q3 2022 contract price records set in all regions

Contract prices remained high in Q3 2022 despite falling in comparison to the record high Q2 (Figure 9.1). The final base future prices settled at between $192/MWh in Victoria and $232/MWh in South Australia, setting new records for the highest base future prices ever observed in a Q3. Previous records were shattered, up 90% to 180% in each of the 4 regions.

Final prices were lower than initially anticipated at the start of the quarter. Early in the quarter market participants expected NSW to be the highest priced region, with contracts settling at $345/MWh. Price expectations fell as spot prices fell off in the second half of the quarter. South Australia ended up the highest price region, within $5/MWh of both Queensland and NSW. Victoria was the lowest priced region, more than $30/MWh less than the other 3 regions.

Figure 9.1 Q3 2022 base future final prices ease after Q2 surge

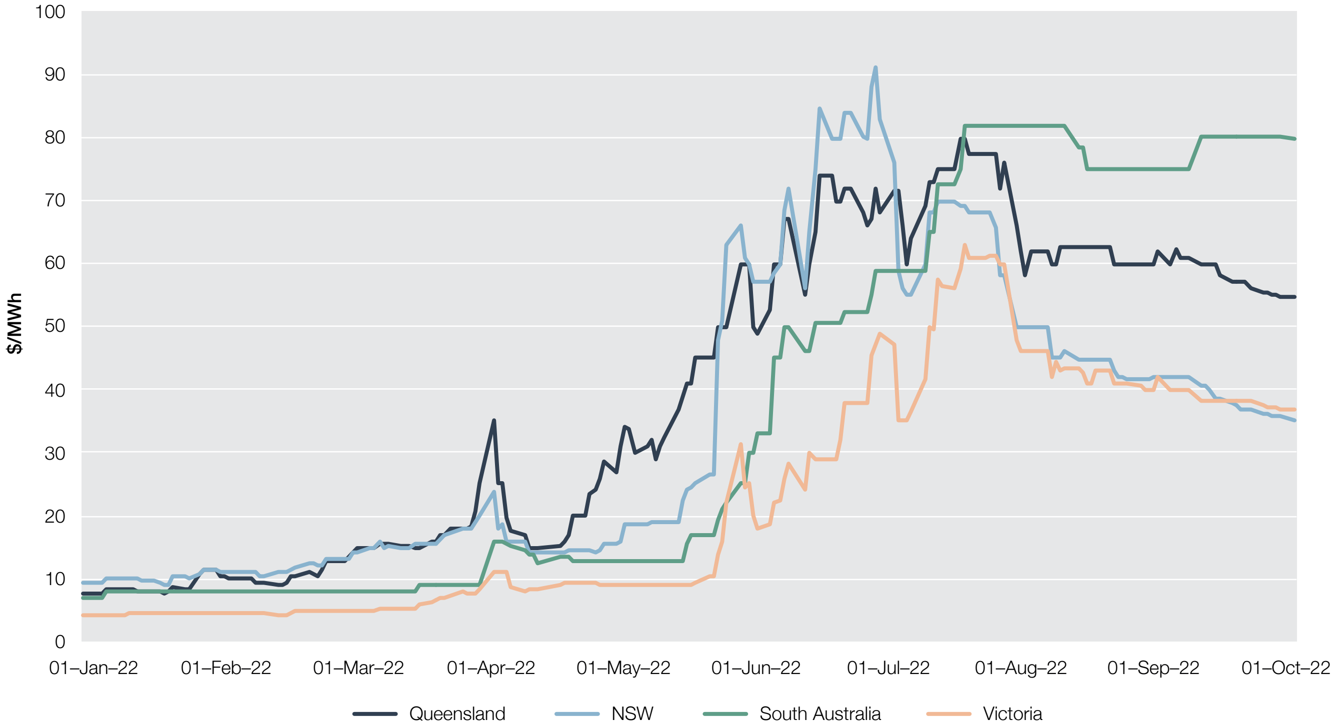


Source: AER analysis using ASX data.

Note: Daily settled price for Q3 2022 quarterly base futures. Final base future numbers are the contract value at settlement, the quarterly average spot price.

Final Q3 2022 cap prices ranged from $34/MWh in NSW to $80/MWh in South Australia (Figure 9.2). Final cap prices more than doubled the previous Q3 records in all regions. South Australia was the highest priced region at $80/MWh, beating the previous record of $34/MWh set in Q3 2016 following the Northern power station closure. Such high cap payouts are unprecedented in most regions during Q3. In Victoria, for example, every Q3 cap payout since the NEM commenced was less than $3/MWh. This year the final Q3 cap payout in Victoria was $36/MWh, beating the previous Q3 record 12-fold.

Figure 9.2 Q3 2022 cap final prices double previous Q3 records

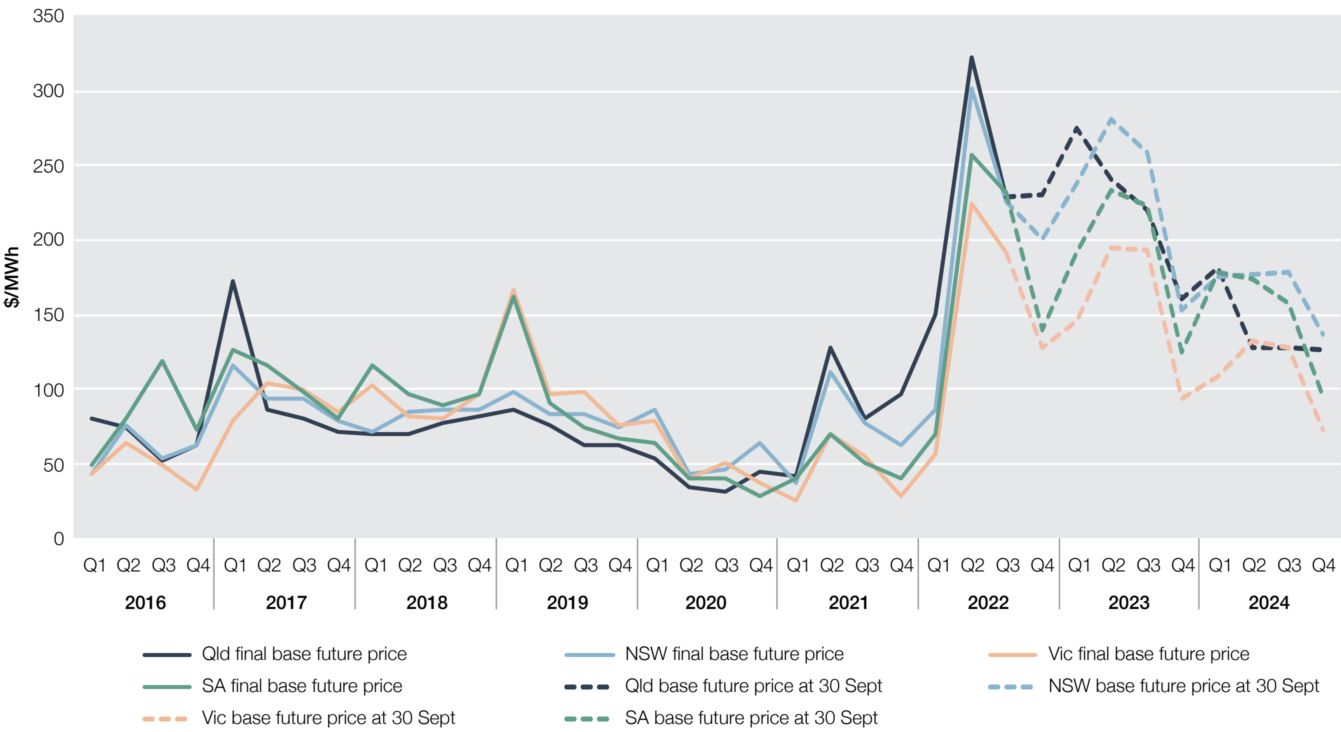


Source: AER analysis using ASX data.

9.1.2 Future electricity price expectations

Forward base future price expectations remain elevated into 2023 and 2024 (Figure 9.3). Prices are expected to fall in Q4 2022 before rising again in 2023. Forward price expectations are highest in winter 2023. Current price expectations for winter 2023 range from $190/MWh in Victoria to $280/MWh in NSW. The key drivers for continued high price expectations are varied but include expected high international gas and coal prices, uncertainty around reliability of base load coal generation, local coal supply issues, forecast La Niña weather conditions and the closure of the final 3 units at Liddell Power Station on 1 April 2023, tightening supply.

Figure 9.3 Forward base future price expectations remain elevated into 2023



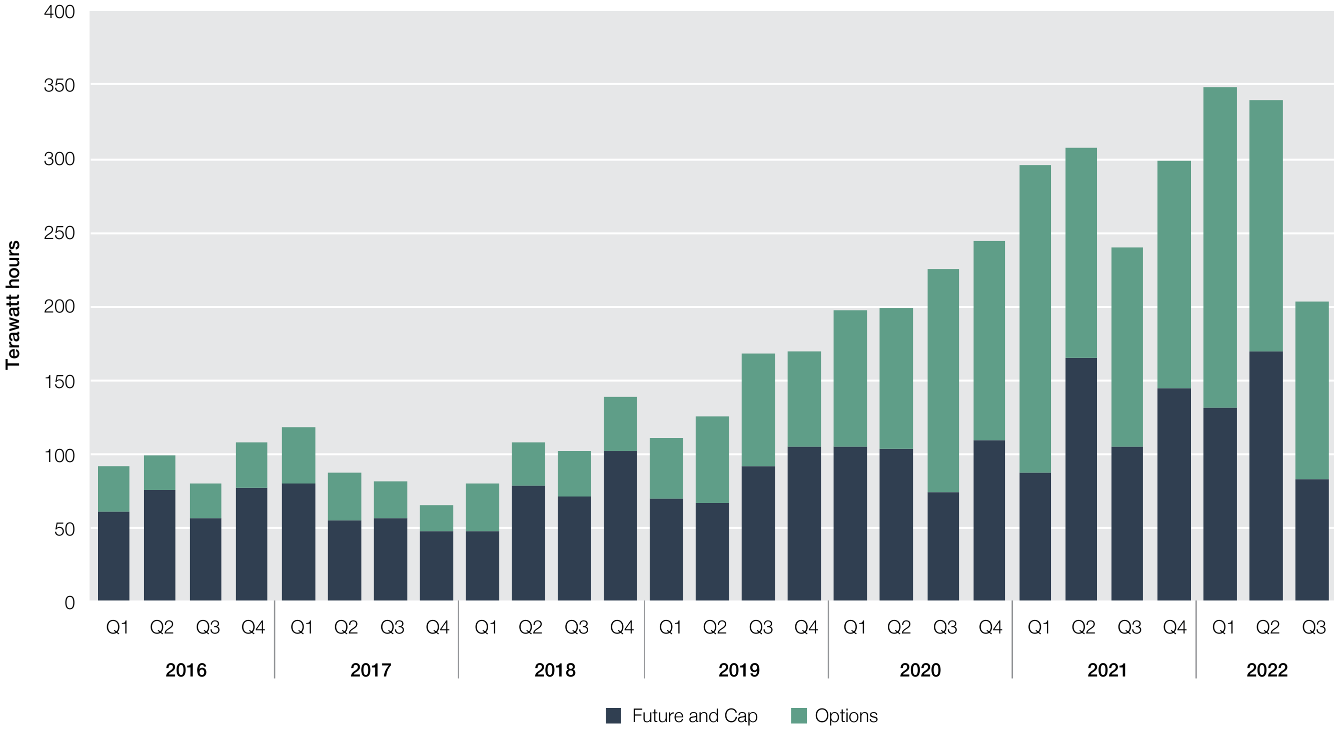
Source: AER analysis using ASX data.

Note: Prices for Q1 2019 to Q3 2022 base futures are final base future prices. Prices for Q4 2022 base futures and beyond are at 1 October 2022.

9.1.3 Trade volumes

Traded contract volumes decreased in Q3 compared to recent quarters (Figure 9.4). The volume traded during the quarter was 203TWh, the lowest quarterly traded volume since mid-2020. Traded volumes were lowest in July, falling to 46TWh before increasing in August (78TWh) and September (80TWh).

Figure 9.4 Traded contract volumes decreased in Q3 2022



Source: AER analysis using ASX data.

Traded volumes have grown significantly since 2017. A large amount of this growth has been due to increased trading of options. Option volumes have increased 5-fold in the past 5 years. Until 2018, options accounted for around 30% of traded volume. This has increased to 55% in 2020 and 2021. In 2022 to date, options account for 57% of traded volume.

There are 2 types of options available on the ASX, the base strip option and the average rate option. The base strip option is the most popular, accounting for more than 90% of traded volumes of options in 2021. The base strip option allows the buyer to lock in a price for a strip of base futures for either a calendar year or financial year. The buyer has until 6 weeks before the start of that year to decide whether they want to exercise the option and convert the option into base futures. Options are a way for parties to hedge against an uncertain and volatile market, so it is not surprising the volume of these has increased given current market conditions.

9.1.4 Coal futures

Newcastle coal forward prices at 30 September were expected to remain above $550/tonne in 2023 and above $480/tonne in 2024.[23] These high coal prices will tend to continue to put pressure on local fuel costs. Supply is expected to remain tight on projected stronger European coal demand as the region shifts its energy sources away from Russian coal and gas.

9.2 Gas ASX futures and Wallumbilla forward trades

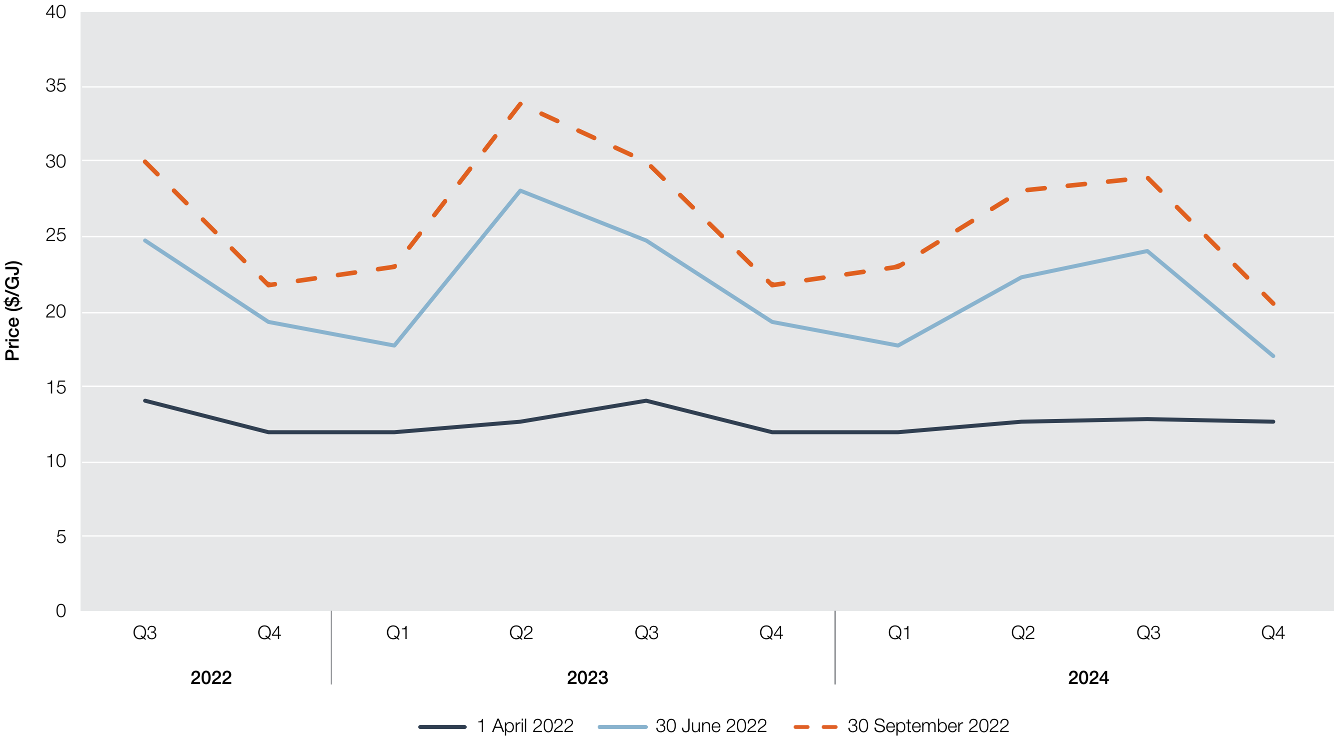
Gas futures prices have been rising since April 2022. Victorian gas futures traded in Q3 2022 indicated traders expect gas prices to remain high. Futures prices as at 30 September 2022 for Q3 2022 settled at $30/GJ, with expected prices for Q2 and Q3 2023 rising above $30/GJ (Figure 9.5).[24]

23 $AUD.

24 ASX, Energy Derivatives, Australian Electricity, accessed 3 October 2022.

These increases reflect increased spot prices and expectations that higher prices are likely to be sustained in the short to medium term.[25] Peak Victorian winter demand typically occurs in Q3, and it is likely traders are taking possible tight supply/demand conditions over that period into account.

Figure 9.5 Comparison of Victoria futures prices, April, June and September 2022



Source: ASX Energy.

A small number of trades on the gas supply hub for delivery at Wallumbilla into 2023 have also taken place at prices around $30/GJ.[26] While trading volumes for Victorian futures and forward volumes for gas supply hub trades are relatively low compared to downstream market volumes, these higher trade prices are indicative of continued higher market price environment into 2023.

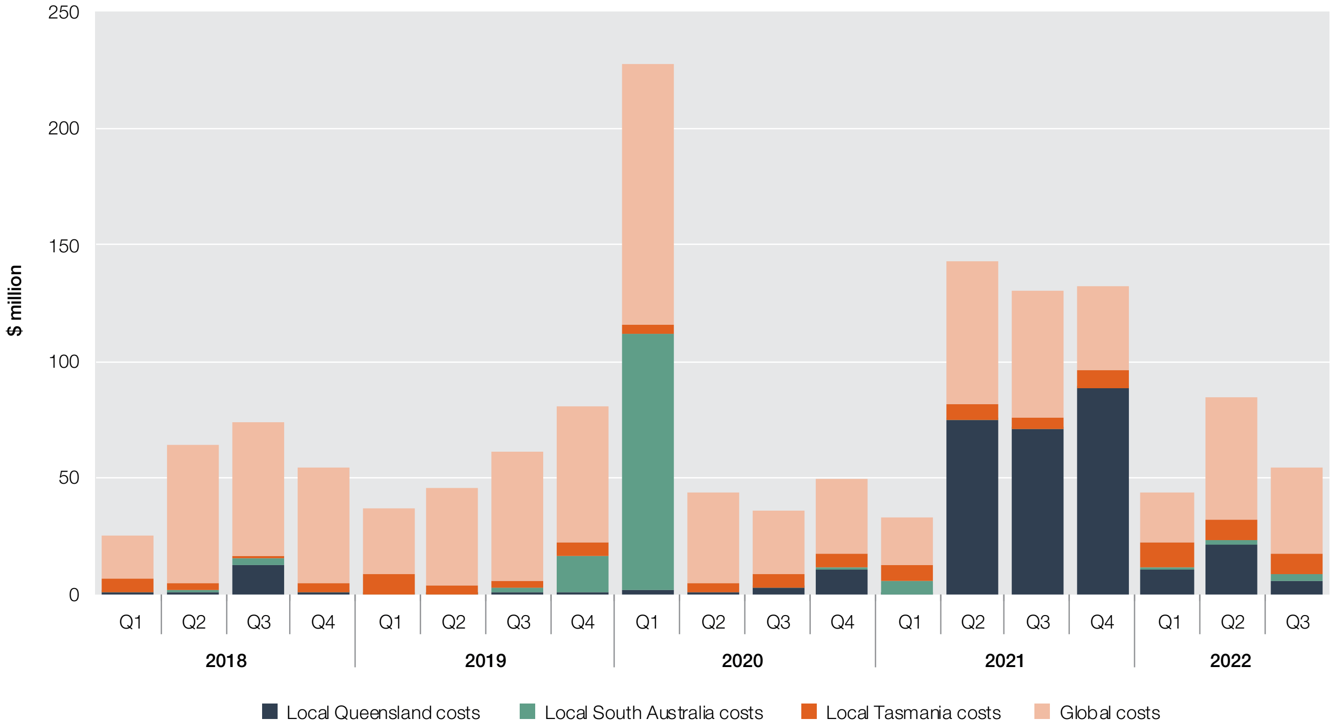
25 It should be noted that gas futures on the ASX are thinly traded and there is usually a large difference between bids and offers for these products on the exchange. Settlement prices for ASX gas futures usually reflect the lower part of this range but actual market expectations may be somewhat higher. For example, the offer price for a Victorian gas futures contract for Q3 delivery was $25/GJ in early May.

26 Volumes of 1 to 4 TJ per day have been traded over monthly delivery periods out to August 2023 at prices between $28–$31.50/GJ.

10. FCAS costs fell in Q3 2022

Local Frequency Control Ancillary Services (FCAS) costs in Queensland declined significantly in Q3 2022 compared to Q3 2021. With fewer planned outages on the Queensland-NSW interconnector (QNI) Queensland didn't need to provide its own FCAS as often. QNI upgrade work was completed in June 2022, and testing and commissioning occurred in September.

Figure 10.1 FCAS quarterly costs fall



Source: AER analysis using NEM data.

Note: Global and local FCAS costs, by quarter.

11. Electricity focus – Bidding behaviour on the Basslink interconnector

11.1 The Basslink interconnector is unique

The AER regulates pricing for all major networks in the NEM, other than the Basslink interconnector linking Victoria and Tasmania. Basslink is a Market Network Service Provider (MNSP) with its capacity to transfer energy bid into the spot market similar to a generator. Revenue under this structure is market-based, that is, determined by price differences and energy flows between Victoria and Tasmania. Directlink and Murraylink interconnectors (connecting NSW and Queensland, and Victoria and South Australia) were formerly MNSP's, but are now regulated assets.

Basslink operated according to a long-term agreement (the Basslink Services Agreement) between its owners and Hydro Tasmania between 2006 and 2022. Hydro Tasmania is the predominant electricity generator in Tasmania, owned by the state government. The service agreement allowed the owners of Basslink to swap its market-based revenue for an agreed fixed facility fee plus performance-related payments, as well as giving Hydro Tasmania rights to control the way Basslink capacity is bid.[27] That is, the agreement gave Basslink revenue certainty and gave Hydro Tasmania a large amount of certainty about the capacity available to move energy to and from Victoria.

11.2 Basslink has faced problems in recent years, and entered into administration

Between December 2015 and June 2016, the Basslink interconnector was forced offline for 6 months due to a fault in the undersea cable. This occurred during a time when Tasmania's hydroelectricity storage was depleted by drought, and gas generation was offline. Following investigation into the incident, in late 2017 expert reports recommended an export limit of 500 MW on Basslink.[28] At this time, all capacity on Basslink was generally bid into the market at 1 cent. In late 2019, Hydro Tasmania exercised its rights under the service agreement to instruct Basslink Pty Ltd to bid Basslink's capacity above certain levels at the market cap price, to reduce the risk of the cable operating above design limits.[29]

Due to the outage, Basslink Pty Ltd owed Hydro Tasmania a significant amount in damages. Further, Basslink faced issues because of an unsuccessful sale process, and ongoing disputes with Hydro Tasmania. This led Basslink's owners to put the business into voluntary administration in November 2021, with EY as administrators and KPMG initially appointed as receiver and manager.[30,31]

In February of 2022 the services agreement was terminated by Hydro Tasmania after ongoing breaches of the agreement (both technical and financial) were unable to be resolved between the receivers and the state and Hydro Tasmania.[32] Basslink operators then reverted to trading under commercial terms.[33]

11.3 Administration arrangements affected bidding behaviour

Basslink's bidding behaviour did not change with the appointment of KPMG as receivers. However, in June 2022, FTI Consulting were appointed as the Basslink Pty Ltd receiver and manager. From July to September 2022 bidding behaviour changed. Rather than bidding its capacity across just 2 price bands, Basslink bid over a range of price bands and more capacity was offered at higher prices, both for northward and southward flows across the interconnector.

27 Electricity Supply Industry Expert Panel, 'Basslink: Decision making, expectations and outcomes', December 2011.

28 Hydro Tasmania, 'Basslink cable failure investigation', 20 December 2017.

29 Hydro Tasmania, 'Market update regarding Basslink bidding instructions', 18 October 2019.

30 Basslink, 'Basslink Enters Voluntary Administration', 12 November 2021.

31 Basslink, 'Basslink placed into receivership', 12 November 2021.

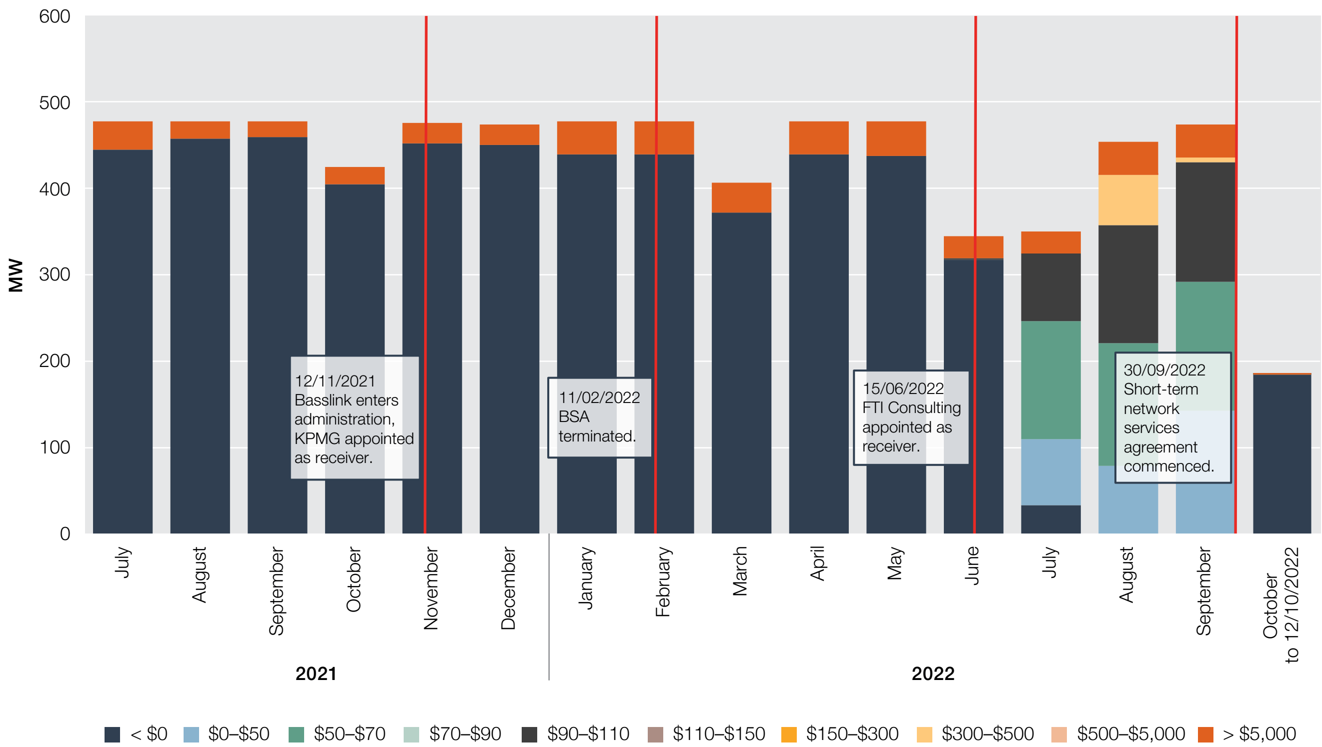
32 Parliament of Tasmania – Hansard, Parliamentary Standing Committee on Public Works, 17 June 2022.

33 Hydro Tasmania, 'Further update on Basslink arrangements', 16 February 2022.

For example, Basslink reduced bids at $0.01 for northward flows significantly in Q3 2022, and instead, split the majority of offers between the higher price bands of $1.01–$50/MWh, $50–$70/MWh and $90–$110/MWh (Figure 11.1). Basslink also decreased its average availability over a 5-minute trading interval in June and July 2022, after it was relatively stable (with a small number of exceptions) at the maximum availability of 478 MW, though this increased again in September 2022.

As of 30 September 2022, Hydro Tasmania and FTI Consulting established an agreement requiring the receivers to use reasonable endeavours, having regard to its resources, to make Basslink available to the market at its safe continuous capacity at zero price.[34] This agreement is subject to conditions around the acquisition of Basslink Pty Ltd. In October, the receivers consistently bid Basslink availability into the market at low prices.

Figure 11.1 Basslink average offers, monthly, Tasmania to Victoria flow



Source: AER analysis using NEM data.

Note: Data shows the bid for northward flows on the interconnector. Data was collected up until 12 October.

Unlike other interconnectors, as Basslink is an MNSP and not a regulated asset, operators of Basslink can stop transmission of energy across the interconnector by bidding zero availability into the market. Prior to June 2022, availability was reduced to zero only around 10% of the time, primarily due to physical reasons such as maintenance or planned outages. Instances of zero availability increased to around 13% of the time from July to September 2022. The increase came primarily from southward bids from Victoria to Tasmania, with zero availability bid into the market around 16% of the time, often to manage counter-price flows.

Counter-price flows were not a factor for Basslink under the original service agreement because its operators received a fixed facility fee plus performance-related payments. Without the service agreement, the operators were more exposed to losses when there were instances of counter-price flows (where electricity is exported from a high price region into a lower priced region). During these counter-price events, while FTI consulting was managing operations, Basslink bid zero availability into the market more often. This behaviour also occurred during June during the market suspension, and while the administered price cap was in place, again, likely to minimise losses.

Overall, the changes to bidding behaviour appear to have had no apparent effect on prices in either Tasmania or Victoria, with prices falling in both regions in August and September (section 1.3).

Notably, after the short-term network services agreement between Hydro Tasmania and FTI Consulting commenced, there were no instances of zero availability being bid into the market for flows in either direction. The agreement required the receivers to make Basslink available at its safe continuous capacity at zero price and was subject to conditions around the acquisition of Basslink Pty Ltd and establishment of a further network services agreement.

34 Hydro Tasmania, 'Update regarding Basslink contract arrangements', 30 September 2022.

11.4 Likely end of Australia's last unregulated interconnector

On 24 October 2022 Hydro Tasmania confirmed that energy infrastructure business APA Group completed the purchase of Basslink Pty Ltd for $773 million. As part of the sale transaction, Hydro Tasmania and Basslink Pty Ltd entered into a network services agreement that commenced on 21 October 2022 and will conclude on the earlier of:

- regulation of Basslink by the AER
- 30 June 2025, unless extended by the parties.[35]

There have been no further changes to bidding behaviour, with availability still being bid into the interconnector at a consistent, low, price band. APA Group have previously stated their intention to work to convert Basslink to a regulated asset with regulated revenues.[36]

35 Hydro Tasmania, 'Updated Basslink agreement', 16 February 2022.

36 APA Group, 'APA to acquire Basslink', 18 October 2022.

12. Gas focus – New capacity certificate regime

On 1 January 2023, a new capacity certificate regime will replace the current authorised maximum daily quantity (AMDQ) regime which allocates transportation rights in the Victorian Declared Transmission System. These rights have real effects on the conduct of market participants and associated market outcomes. Under the old regime, established participants could rely on capacity rights to reduce curtailment (where gas cannot be transported during periods of congestion) and avoid congestion charges. This left the burden of congestion to fall on participants without capacity rights.

The implementation of the new regime follows an AEMC rule change in March 2020 but was delayed to allow existing AMDQ rights under long-term contracts to expire.[37] As part of the transition to the new regime, AEMO conducted 2 auctions of capacity certificates (for January 2023 to December 2025), which finished on 4 November 2022. The next auction commences on 16 November and will sell further auction capacity for 2023 to 2025.

The two gas transportation capacity allocation regimes are similar in nature, providing injection and withdrawal rights in the transmission system, but the new regime aims to be more equitable and less complex. It creates a level playing field for all market participants to obtain capacity certificates through regular auctions which allow certificates to be allocated to those that value them most and promote the efficient use of pipeline capacity. These certificates can also be traded with other participants and to facilitate this, AEMO is required to provide a secondary capacity trading listing service and report on secondary capacity trades.[38]

Under the old regime, when participants' gas was equally priced, priority pipeline access was given to participants with AMDQ rights (referred to as tie breaking). AMDQ was also used to determine whose gas was transported during emergency events while other gas was curtailed. In addition to these benefits, participants with AMDQ rights were insulated from paying uplift charges when there is not enough capacity to transport the cheapest gas and more expensive gas is sourced via an alternate route.

The new regime continues to provide tie-breaking rights but changes the way uplift charges are allocated to market participants and removes curtailment protections. Collectively these changes allocate costs and risks across the market more equitably and reduces the unfair burden on participants without existing capacity rights.

Table 12.1 Key differences and similarities between the old and new regimes

PREVIOUS AMDQ REGIME	CAPACITY CERTIFICATES REGIME
› Protection from congestion uplift (burden of paying for managing congestion falls on participants without capacity rights). › Curtailment protection (flow gas when other participants cannot). › Credit certificates impart long term rights. › Tie-breaking rights.	› Congestion uplift removed for all participants. › No protection from curtailment. › Rights can be acquired for a shorter time period allowing more flexibility. Auctions held at least twice a year. › Tie breaking rights remain.

12.1 AER is monitoring the new capacity certificates which may have significant value at times

Capacity certificate auctions give insights into which participants are able to exercise market power with initial auction results indicating the market is highly concentrated. For example, the 2 transitional auctions which closed on 4 November allocated around 60% of Gippsland entry credit certificates to a small number of participants, along with other entry and exit certificates at different DWGM points. Most interest was in entry certificates for next July and August.

Capacity certificates for the Gippsland entry point may be particularly valuable at times if they determine whose gas enters the market from the Longford production facility. Longford is the main supplier of gas to the Victorian market but is an ageing facility and prone to outages. Following an outage, participants with capacity certificates will be

37 AEMC, DWGM improvement to AMDQ regime rule change.

38 AEMC, Rule determination, National gas amendment (DWGM improvement to AMDQ regime) Rule, 12 March 2020, Table 6.1, p. 90.

given priority because of their tie-breaking rights. As AEMO is required to report when tie-breaking has occurred and when certificate holders have been given preference, over time this will inform the market of the value of capacity certificates. Industry is likely to consider the risk of outages (and high prices) and assess when capacity certificates might have their highest value.

The first regular capacity certificate auction which opens on 16 November will auction a further 150–250 TJ per day of monthly Gippsland entry credit certificates for the years 2023, 2024 and 2025 along with other entry and exit credit certificates at different DWGM points. The AER will be monitoring the outcomes of the auctions and reporting on the level of competition and trade for these certificates, including any secondary trades which occur.

Appendix A – Market participants

PARTICIPANT LIST IN EASTERN GAS MARKET							
	Market participant	Victoria	Sydney	Adelaide	Brisbane	GSHs	DAA
GPG Gentailer	AGL	●	●	●	●	●	●
	Alinta Energy	●	●	●	●	●	●
	CleanCo				●	●	●
	EnergyAustralia	●	●	●		●	●
	Engie	●					●
	Hydro Tasmania	●	●				
	Origin	●	●	●	●	●	●
	Shell Retail	●	●	●	●	●	●
	Snowy Hydro	●	●	●	●		
Exporter/Producer	Arrow		●		●	●	●
	APLNG					●	●
	Beach Energy	●					
	BHP Billiton	●	●				
	Cooper Energy	●					
	Esso	●	●				●
	GLNG					●	
	Lochard Energy	●					
	Santos	●	●	●	●	●	●
	Senex	●	●		●	●	●
	Shell	●	●	●	●	●	●
	Walloons Coal Seam Gas (QGC)					●	●
	Westside Corporation					●	●
Retailer	1st Energy	●					
	Agora	●					●
	Covau	●	●	●	●		
	CPE Mascot		●				
	Delta Electricity		●				
	Discover Energy	●	●	●	●		
	Dodo	●	●				
	GloBird Energy	●	●	●	●		
	OVO Energy	●					
	ReAmped Energy		●				
	Powershop*	● ●	● ●				
	Simply Energy		●	●			
	Sumo Gas	●	●				
	TasGas	●					
	Tango	●					
	Weston Energy*	● ●	● ●	● ●	● ●		● ●

Industrial	Adelaide Brighton Cement			Entered before 2017			
	Ampol				Entered before 2017		Entered in 2022
	BlueScope	Entered in 2021	Entered before 2017		Entered in 2018		
	Boortmalt	Entered in 2019	Entered in 2018	Entered in 2018			
	Brickworks	Entered in 2020	Entered in 2020	Entered in 2020	Entered in 2020	Entered in 2022	Entered in 2022
	Commonwealth Steel		Entered in 2017				
	Coopers			Entered in 2017			
	CSR Building Products	Entered in 2018	Entered in 2021	Entered in 2019	Entered in 2018		
	Group Energy		Entered in 2022				
	Incitec Pivot				Entered before 2017	Entered before 2017	Entered in 2019
	Infrabuild	Entered before 2017	Entered before 2017	Entered before 2017		Entered in 2022	Entered in 2022
	Master Butchers			Entered in 2020			
	Michell Wool			Entered in 2019			
	Mobil Oil	Entered in 2018					
	Oceania Glass	Entered in 2020					
	Orica		Entered in 2017			Entered in 2022	
	Paper Australia	Entered in 2018	Entered in 2020				
	Qenos	Entered in 2017	Entered before 2017			Entered in 2017; Exit or inactive	Entered in 2019
	SA Water			Entered before 2017			
	Tarac Technologies		Entered in 2017	Entered before 2017			Entered in 2019
	Visy	Entered before 2017	Entered before 2017	Entered before 2017	Entered before 2017		Entered in 2020
	Viva Energy	Entered in 2018					
	Weston Aluminium		Entered before 2017				
Trader	Eastern Energy Supply	Entered in 2020	Entered in 2020	Entered in 2020	Entered in 2020	Entered in 2020	Entered in 2020
	Macquarie Bank	Entered in 2019	Entered in 2019			Entered in 2018	Entered in 2019
	Petro China	Entered in 2020	Entered in 2020		Entered in 2021	Entered in 2019	Entered in 2020
	Strategic Gas Market Trading	Entered in 2019	Entered in 2019	Entered in 2021	Entered in 2020	Entered before 2017	Entered in 2019
	63	41	39	25	22	22	27

● Entered before 2017 ● Entered in 2017 ● Entered in 2018 ● Entered in 2019 ● Entered in 2020 ● Entered in 2021 ● Entered in 2022
● Exit or inactive

Note: For Victoria, Adelaide, Sydney, Brisbane and the GSH the year represents when participants commenced trading. For the DAA the year represents when participants registered.

* Weston Energy's authorisation to trade in the gas markets was revoked on 24 May 2022.
* Click Energy was acquired by AGL, ERM and Powershop were acquired by Shell (Shell Retail), O-I International was acquired by Visy.
* Arrow also operates the Braemar 2 power station.
* Simple Energy is the retail arm of Engie, who own and operate gas generation assets in South Australia.
* ICAP Brokers is also active in the GSH, but does not trade gas commodities (trade facilitior).

Common measurements and abbreviations

ELECTRICITY		GAS	
MW	Megawatt	GJ	Gigajoule
MWh	Megawatt hour	PJ	Petajoule
TW	Terawatt	TJ	Terajoule
FCAS	Frequency control ancillary services	STTM	Short Term Trading Market
NEM	National Electricity Market	DWGM	Declared Wholesale Gas Market
VWA	Volume weighted average	WGSH	Wallumbilla Gas Supply Hub
AEMO	Australian Energy Market Operator	DAA	Day Ahead Auction
		BWP	Berwyndale to Wallumbilla Pipeline
		CGP	Carpentaria Gas Pipeline
		EGP	Eastern Gas Pipeline
		ICF	Iona Compression Facility
		MAPS	Moomba to Adelaide Pipeline System
		MCF	Moomba Compression Facility
		MSP	Moomba to Sydney Pipeline
		NGP	Northern Gas Pipeline
		PCA	Port Campbell to Adelaide Pipeline
		PCI	Port Campbell to Iona Pipeline
		QGP	Queensland Gas Pipeline
		RBP	Roma to Brisbane Pipeline
		SWQP	South West Queensland Pipeline
		TGP	Tasmanian Gas Pipeline
		VicHub	Eastern Victorian supply/demand point
		WCFA	Wallumbilla Compression Facility A
		WCFB	Wallumbilla Compression Facility B

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