Significant price variation report

July price variations in the Adelaide and Sydney Short Term Trading Markets

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AUSTRALIAN
ENERGY
REGULATOR

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1 Obligation

The Australian Energy Regulator (AER) regulates energy markets and networks under national legislation and rules in eastern and southern Australia (known as the National Energy Market), as well as networks in the Northern Territory. Its functions include:

- monitoring wholesale electricity and gas markets to ensure energy businesses comply with the legislation and rules, and taking enforcement action where necessary;
- setting the amount of revenue that network businesses can recover from customers for using networks (electricity poles and wires and gas pipelines) that transport energy;
- regulating retail energy markets in Queensland, New South Wales, South Australia, Tasmania (electricity only), and the ACT;
- operating the Energy Made Easy website, which provides a retail price comparator and other information for energy consumers;
- publishing information on the performance of energy markets, including the annual State of the Energy Market report and biennial effective competition report, to assist stakeholders and the wider community.

In accordance with the National Gas Rules (the Rules), the AER is required to publish a report whenever there is a significant price variation (SPV) in the Victorian Declared Wholesale Gas Market (DWGM) or Short Term Trading Markets (STTM).[1]

The AER has published guidelines setting out what constitutes a SPV event.[2] Outcomes that constitute a SPV in the STTM – the focus of this report – include when there is a variation of greater than $7/GJ between the price 2 days prior (D-2) and the price the day before (ex ante or D-1).

Over the month of July 2021, there were 9 occasions where deviations between the provisional (D-2) and ex ante (D-1) prices exceeded $7/GJ. This impacted the Adelaide STTM on one occasion, with the remaining 8 threshold breaches occurring in the Sydney STTM. The majority of these threshold breaches saw reduced ex ante prices resulting from participants responding to provisional market pricing signals, with 2 instances of ex ante prices increasing above provisional forecasts. The individual gas days of each significant price variation are shown in the following table (Table 1).

1 The obligation is set out in the National Gas Rules. Rule 498(3)(b) relates to SPVs in the Short Term Trading Markets, and rule 355(1)(b) relates to SPVs in the Victorian market.

2 The AER has established thresholds that, when breached, trigger an SPV report. These thresholds are available on the AER website https://www.aer.gov.au/wholesale-markets/guidelines-reviews/significant-price-variations-inthe-sttm-reporting-triggers

Table 1 Significant price variations in July

STTM hub	Date (gas day)	Price ($/GJ) Provisional (D-2)	Ex ante (D-1) higher/lower
Sydney	1 July	20.99	12.59
Sydney	7 July	19.00	27.56
Adelaide	9 July	20.00	28.00
Sydney	14 July	26.00	17.74
Sydney	15 July	22.45	13.75
Sydney	17 July	22.45	14.30
Sydney	19 July	23.78	16.24
Sydney	26 July	25.00	15.00
Sydney	27 July	21.70	13.05

In preparing this report the AER held meetings with AEMO and 6 representative participants active in the Adelaide and Sydney STTMs. These meetings assisted with considering compliance of trading activities with the national gas rules and the market circumstances on the relevant gas days.

2 Summary

Gas market prices increased over winter 2021, rising above $10/GJ from early June, the first instance of sustained market prices above this level since April 2019. In July, price volatility increased as a number of factors contributed to tight supply-demand conditions, with the largest price impacts observed in southern gas markets. In Adelaide, Sydney and Victoria, prices were above $20/GJ 16 times on 7 days. High prices were particularly prevalent across the first half of July.

There were a number of factors driving higher prices:

- As gas production remained strong in the north, so too did LNG export levels. Exports remained at higher levels than previously observed for this time of year, reducing the amount of excess supply that would ordinarily be provided to meet domestic demand.
- Typical increases to market demand in southern regions for winter combined with moderate to high gas powered electricity generation (GPG) requirements across multiple regions on particular days.
- Increasing demand coincided with reduced storage levels at Iona, having provided unprecedented levels of daily gas supply across June.
- While Iona storage was reduced, there was also a partial outage impacting Longford production capacity. These two facilities are the largest sources of gas in Victoria.
- Upstream pipeline demand limited gas moving south from Queensland making its way into southern markets via the Moomba to Adelaide and Moomba to Sydney pipelines.

In particular, there was significant price volatility between the D-2 and ex ante schedules:

- Tight supply-demand conditions drove volatility in forecast pricing, with small changes in demand able to drive significant price swings in the southern markets.
- High coincident demand across southern regions, and relatively high GPG requirements influenced bidding behaviour across participants' market portfolios.
- Significant changes in gas supply offer quantities and prices were a driver of deviations between D-2 and D-1 prices in the STTMs.
- The majority of deviations supressed ex ante prices below forecast levels, there was one instance in Sydney (7 July) and one in Adelaide (9 July) where the ex ante price increased by more than $7/GJ.

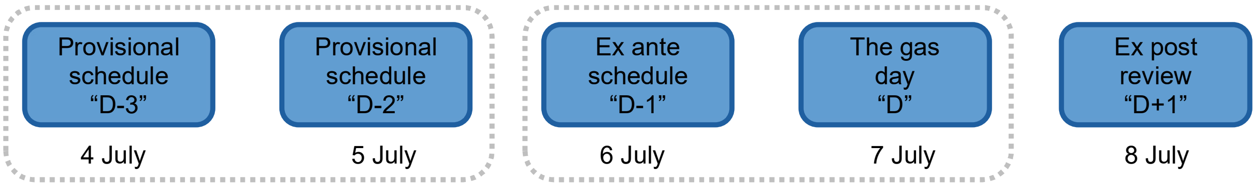
Some producers only offer quantities of gas into the D-1 schedule most of the time, and have indicated to the AER this is due to uncertainty as to the quantity of gas they can supply to the market. In particular, 2 producers consistently have the most significant impact on changes in gas supply offer quantities between the D-1 schedule and the D-2 schedule while usually not offering gas into the D-2 schedule. In general market outcomes are optimised when market participants have access to information as early as possible. The AER will continue to monitor the effect on the market of this practice and may issue further public guidance with respect to when gas supply offer quantities should be included in the provisional schedules.

3 Background

3.1 Short Term Trading Market scheduling

Pricing in the gas short term trading markets occurs through a published, 3 day, price discovery process. Figure 1 below shows schematically how this process operates using the 7 July gas day as an example. Participants make offers and bids first for the schedule three days prior (D-3), which produces a forecast price, then the D-2 schedule, and lastly final submissions including updated/new forecast quantities for the D-1 schedule.[3]

Figure 1 Short Term Trading Market schedule example timeline – 7 July



Rule 410(2) of the Rules sets out the timing for bids and offers into the STTMs:

Rule 410 – Timing of submissions of ex ante offers, ex ante bids and price taker bids

(1) *If a Trading Participant expects to supply quantities of natural gas to, or withdraw quantities of natural gas from, a hub on a gas day, the Trading Participant must submit to AEMO in good faith:*

- *(a) ex ante offers, ex ante bids or price taker bids for that gas day that reflect; or*
- *(b) revisions to an earlier ex ante offer, ex ante bid or price taker bid for that gas day so as to reflect,*

the Trading Participant’s best estimate of the quantities of natural gas it expects to supply or withdraw on that gas day, as at each of the times specified in subrule (2).

(2) *Any submissions required in accordance with subrule (1) must be made no later than:*

- *(a) 7.5 hours after the start of the gas day that is 3 gas days before the relevant gas day; and*
- *(b) if revised or not previously submitted, 7.5 hours after the start of the gas day that is 2 gas days before that gas day; and*
- *(c) if revised or not previously submitted, 5.5 hours after the start of the gas day before that gas day.*

In accordance with rule 410(2), 23 of 34 participants were active in the Sydney market making ex ante offers to supply gas on the 7 July gas day (others being on the demand side only):

- 21 participants submitted D-3 supply offers by the 2 pm deadline on 4 July
- 22 participants submitted D-2 supply offers by the 2 pm deadline on 5 July
- 23 participants submitted D-1 supply offers by the 12 pm deadline on 6 July

[3] Gas quantities include price taker (uncontrollable participant demand forecast) bids, priced bids (for controllable demand), supply offer quantities (for each pipeline facility supplying the STTM hub), and other information such as pipeline capacity limitations.

After the gas day, a further ex post pricing schedule accounts for changes between what was scheduled to be delivered and what was delivered. The focus of this SPV report is not on the ex-post schedule (as reporting thresholds were not reached for differences between ex ante prices and ex post prices).

A couple of participants only submitted ex ante offers most of the time and not D-3 or D-2 offers, and these are noted as being particularly influential on pricing variations in section 5. In general market outcomes are optimised when market participants have access to information as early as possible. The AER has previously noted bidding behaviour in the context of the day ahead auction which may delay the flow of information to downstream markets getting out.[4] The AER is considering further guidelines to outline our expectations on best practice bidding behaviour.

Ultimately, the ex ante price sets the price paid (or sold) for the majority of gas supply traded each gas day in the market. A $7/GJ price change between the D-2 and D-1 schedule for a gas day means overall participants paid or were paid about $490,000 less or more on the basis of 70 TJ being traded each day.[5]

3.2 East coast market supply and demand

East coast gas markets include the STTMs, with hubs located in Adelaide, Brisbane and Sydney, and the DWGM, located in Victoria (Figure 2). Voluntary markets facilitating the trade of upstream gas commodities and transportation services include the Gas Supply Hub (GSH), with locations at Wallumbilla and Moomba, and the Day Ahead Auction (DAA) covering pipeline and compression facilities across the east coast transmission system.

The east coast gas markets are largely supplied from production sources in Queensland (Roma), via onshore conventional and coal seam supply sources, and Victoria from offshore basins (primarily using the Longford production facility). There are also smaller supply sources on the east coast, with the largest located in South Australia at Moomba.

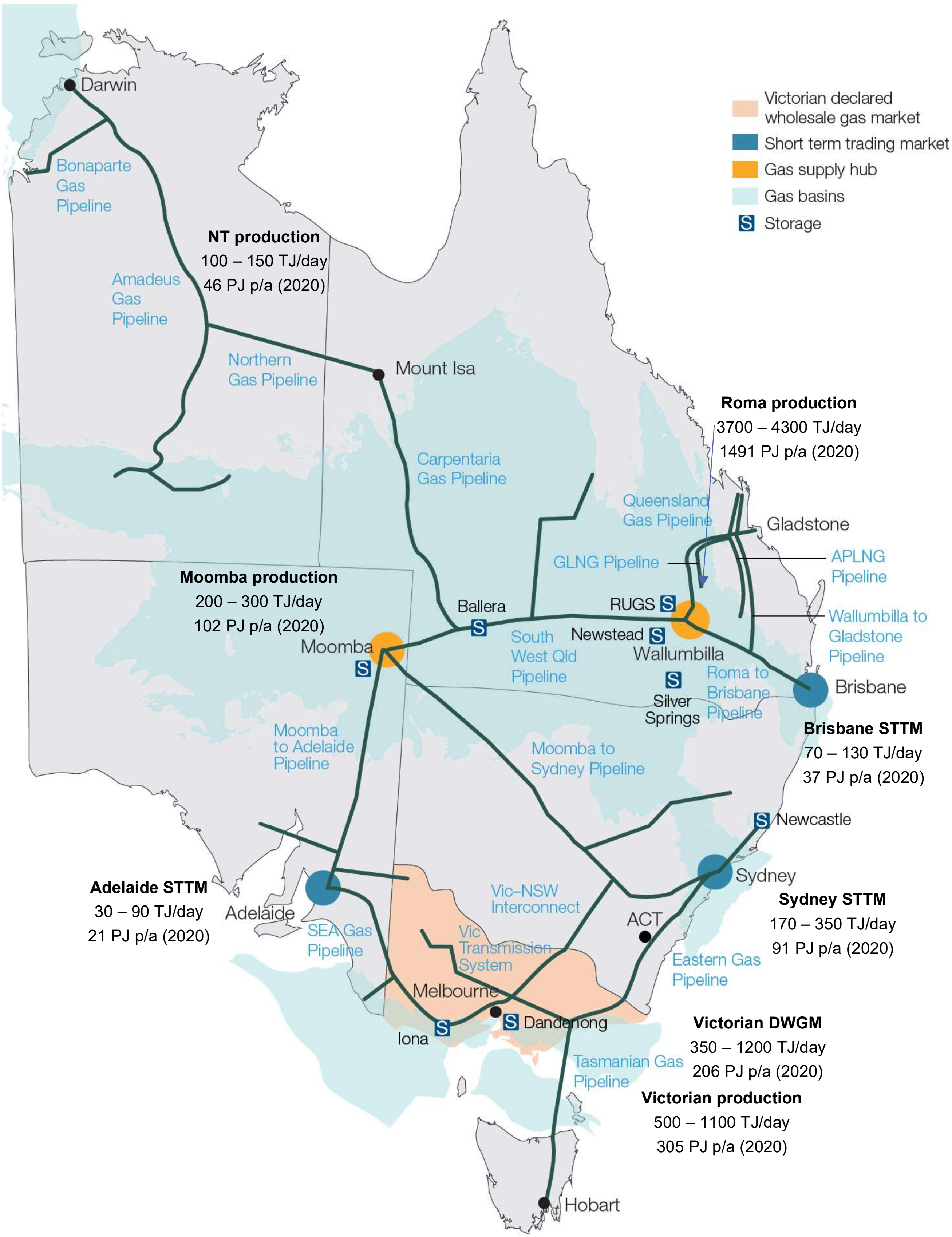
Domestic gas demand typically peaks in winter, influenced by higher demand from residential gas heating (largely driven by Victoria, where a significant proportion of the gas market is comprised of demand from residential gas customers). However, supply and demand requirements can also be influenced by the level of LNG exports being shipped by facilities located in Queensland, and levels of GPG across the eastern states (largely located upstream of the gas markets).[6]

4 AER pipeline capacity trading two year review April 2021.

5 Net trade in Sydney for the month of July was 2170 TJ or around 70 TJ/d.

6 Generation assets in Victoria are largely located within the Declared Transmission System (DTS), and one generation asset in Queensland is located inside the Brisbane STTM. All other GPG are located upstream of the STTM.

Figure 2 East coast gas map with market demand and production quantity



4 East coast gas market conditions over July

This section considers conditions driving high prices in July when the ex ante price variations occurred.

Across the downstream gas markets, prices above $20/GJ were recorded 3 times in Victoria, 6 times in Sydney, 7 times in Adelaide and once in Brisbane. This is the first time so many days priced above $20/GJ have occurred in one month.

The high price conditions across gas markets also had some impact on the days that the AER is required to report on (section 5). At higher prices a $7/GJ change is smaller in relative terms than at lower prices. Moreover at the market clearing price on days over July there was often a large gap between the cheapest and next cheapest offers to supply (or offers to buy). This thinning out of offers meant a small change in the supply demand balance could shift the market clearing price significantly. As the price variation trigger is $7/GJ this meant significant new volumes (or reduction in volumes) to supply or withdraw gas for the ex ante schedule could lead to a price change of $7/GJ or more (see supply and demand stacks in section 5).[7]

Key drivers of high prices in July were:

- Longford production outages
- Iona gas storage pricing changes
- High demand
- Limited but high priced deliveries of gas from the North to the South

In particular Iona scarcity pricing thinned out gas offers, increasing the sensitivity of gas prices to the changes in the supply/demand balance. These are discussed below, followed by an overview of how overall market offers and bids changed over July reflecting these drives.

4.1 Longford production outages

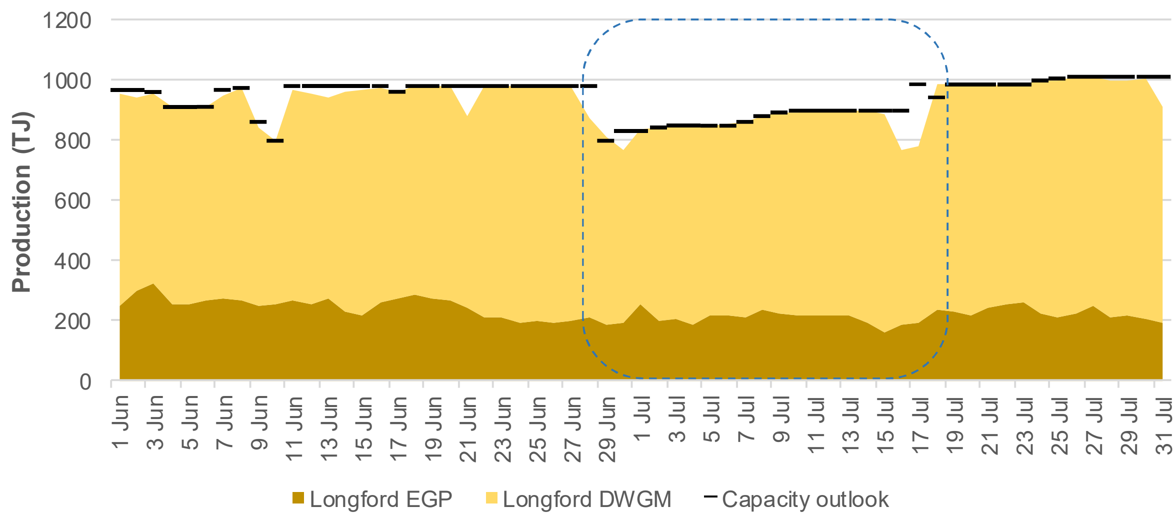
The Longford production facility is the main gas supply source for the southern regions on the east coast, typically providing around 80% to 90% of supply from Victorian production sources. From late June, a partial onshore maintenance outage at Longford reduced the availability of gas supply to southern markets by roughly 100 TJ/day.[8] Longford supply was further impacted following a gas dehydrator issue from 16 July, leading to high schedule pricing in the Victorian market. The reduced output at Longford had a more pronounced impact on supply to the Victorian market, with contracted gas supply on the Eastern Gas Pipeline (EGP) keeping gas flows to NSW from Longford at relatively stable levels (Figure 3).[9]

[7] If prices were always under $7/GJ across all schedules, the AER would never have to report under the D-2, ex ante price trigger.

[8] The medium term capacity outlook indicated an onshore shutdown limiting production capacity to around 850 TJ/day from 3-14 July. Short term outlooks varied around this level from 28 June, but had risen to 900 TJ or higher from 16 July onwards.

[9] Gas can also be delivered to Victoria from the Tasmanian Gas Pipeline (TGP), supplied from Longford production, through the TasHub injection point.

Figure 3 Longford daily production levels



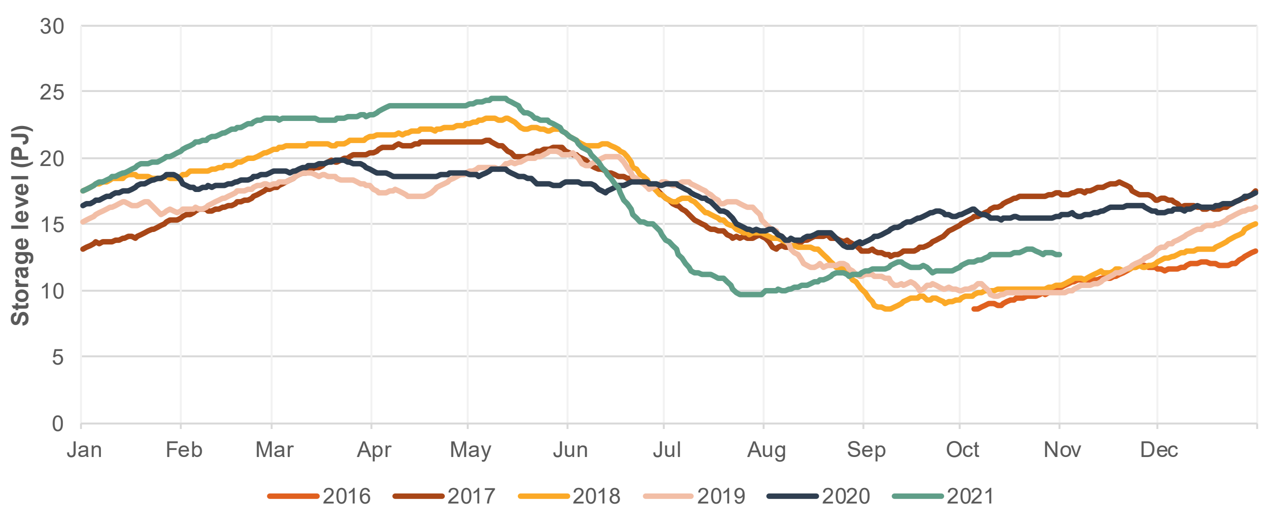
Source: AER analysis using Natural Gas Services Bulletin Board data.

4.2 Iona Underground Storage supply and constrained withdrawals

The Longford outage drove a higher reliance on drawing down storage quantities at the Iona underground storage facility (Victoria's second largest supply source).

In Victoria, the Iona underground gas storage facility was impacted by an unplanned outage in late June related to gas leaking from a corroded pipeline. Following a short term outage to isolate the affected pipeline segment, constraints were applied to the facility which prevented net physical withdrawals of gas into storage from the declared transmission system.[10] Heavy reliance on supply from the facility over June saw injections into the transmission system to supply the gas market reach their highest levels to date, averaging over 250 TJ/day across the month.[11]

Figure 4 Iona daily storage levels over recent years



[10] Repairs at the facility, scheduled to take place from 26 June – 2 July, were extended on two occasions, being pushed out to the end of July. Withdrawals recommenced from 27 July.

[11] Significant supply from storage over July saw the reservoirs reduce to a bit over 9.7 PJ towards the end of the month, falling to just over 40% of the facility's storage capacity of 23.5 PJ. This is the lowest storage levels have been since 2016. The reservoirs were replenished in the following week with some injections into storage during milder weather.

Source: AER analysis using Natural Gas Services Bulletin Board data.

Participants restructured the price of offered supply capacity at Iona across July, while Longford experienced a partial outage limiting supply capacity to Victoria over the first half of the month.[12] These factors led to price setting offers transferring more towards external market supply sources at the Culcairn connection point near the Victorian and NSW border and VicHub connection point linking Victoria to the Eastern Gas Pipeline, as the two largest supply sources were constrained.[13]

Significant Iona supply quantities offered at lower prices had continued from the previous year, frequently more than 200 TJ below $10/GJ from Q2 2020, followed by a noticeable reduction in capacity available below $30/GJ on a number of days from late June. While larger amounts of low priced capacity were offered on higher demand days across July, only a very narrow band of offers were available between $20/GJ and $30/GJ (Figure 5). Capacity offered between $10-20/GJ also narrowed significantly compared to early May, following a planned outage that preceded unplanned maintenance work which limited withdrawals into storage.[14] The impact of this was evident on a number of days where indicative price forecasts showed very high predicted prices given 10% higher demand in the market.[15] High GPG requirements in South Australia in early July also likely had some impact on the use of Iona supply capacity while southern markets experienced concurrent price increases.

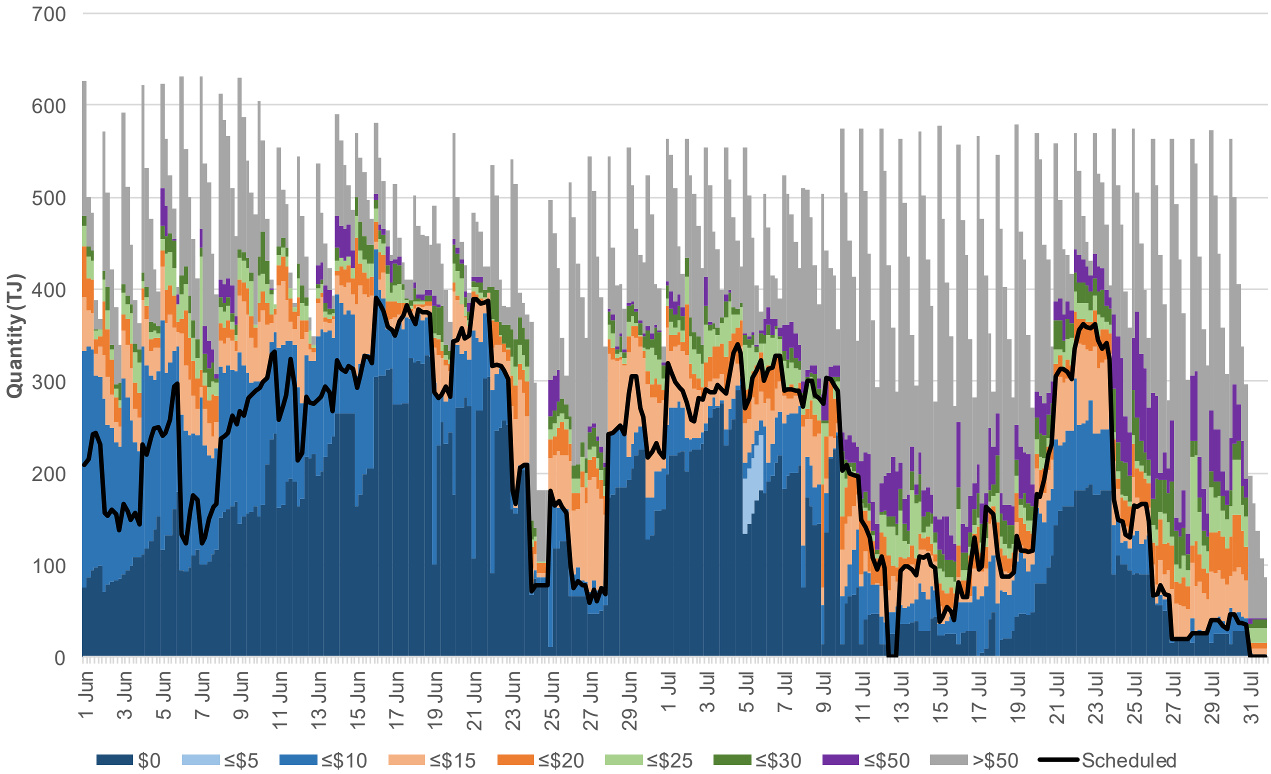
12 Longford supplies gas to the Victorian gas market and the Eastern Gas Pipeline (EGP). Supply to the EGP remained relatively stable above 200 TJ/day across most of July, with the partial outage having a larger impact on supply into Victoria. This can be impacted by unutilised contracted capacity being offered to the Victorian market following participants confirming the use of their contracted production quantities.

13 Culcairn and VicHub are bi-directional system points that transfer gas supply between the Victorian Declared Transmission System (DTS) and interstate pipelines transporting gas between Victoria and New South Wales. The Culcairn system point connects the Moomba to Sydney Pipeline (MSP) to the northern section of the Victorian DTS, while the VicHub system point connects the Eastern Gas Pipeline (EGP) to the eastern section of the DTS. Constraints resulting from upstream gas usage on the Moomba to Sydney Pipeline (MSP) constrained Culcairn supply capacity to Victoria on a number of occasions in July, particularly impacting high priced days in the Victoria, Sydney and Adelaide gas markets over 7-10 July.

14 Analysis in the AER gas weekly report shows the offer prices structure at the Iona underground storage facility from January 2021. https://www.aer.gov.au/wholesale-markets/performance-reporting/gas-report-4-10-july-2021

15 For the 7-10 July gas days, the price sensitivities were above $30/GJ on numerous occasions, rising as high as $120/GJ when Victoria was experiencing high actual market prices on 9 July.

Figure 5 Iona Underground Storage injection bids across daily scheduling intervals



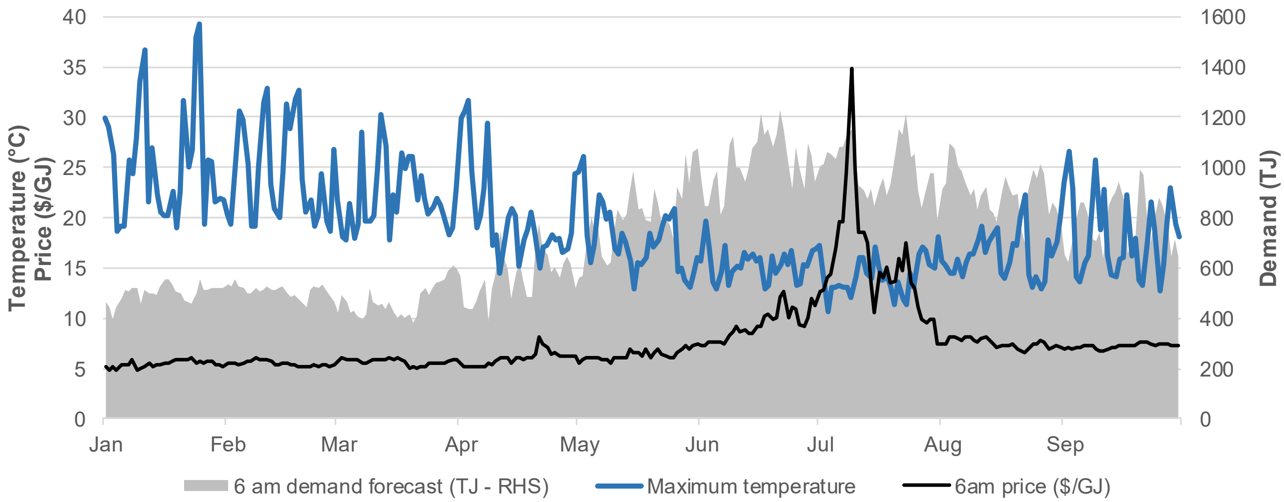
Source: AER analysis using DWGM data.

4.3 High demand conditions

Higher winter demand in southern regions, particularly driven by colder temperatures in Victoria where the maximum temperature in Melbourne averaged just over 14 degrees across July, drove up gas demand across the month. On a number of days this contributed to high levels of coincident demand, with southern regions using 1.4 to 1.6 PJ per day within the Victorian, Adelaide and Sydney gas markets collectively over 5 to 9 July and 21 to 23 July.

Where temperatures dipped, forecast demand in Victoria exceeded 1 PJ per day over 14 days, from 3 to 10 July and 20 to 25 July, with the highest demand levels around 1.1 to 1.2 PJ achieved on 8 to 9 and 21 to 23 July. On these higher demand days, July prices rose above already elevated levels across the gas markets, particularly during Longford's partial outage earlier in the month where southern market prices generally ranged between $20/GJ and $35/GJ over 6 to 13 July.

Figure 6 Victorian market demand (TJ) and price ($/GJ) vs temperature (°C)



Due to the issues constraining cheaper supply availability within Victoria at the large supply sources (Longford and Iona), there was increased utilisation of gas sourced from outside the market through Culcairn (from the north), VicHub and TasHub (in the southeast).

Low wind generation levels and baseload coal outages drove higher GPG requirements and had a significant impact on days with higher gas prices at the start of the month.[16] This added to the higher temperature-driven demand within the markets. Elevated GPG requirements over 5 to 9 July and 21 to 23 July were present across all mainland regions, which also contributed to the higher market demand in Victoria.[17]

In NSW, where GPG use is generally quite low, utilisation of all 4 available gas generator assets occurred over these periods.[18] A large proportion of higher gas generation was supplied from the Uranquinty power station, located just north of the Victorian DWGM on the Moomba to Sydney Pipeline (MSP). Due to its location, alongside other upstream pipeline demand on the MSP, the utilisation of pipeline supply over a number of days constrained the amount of gas that could be supplied further south into the Victorian market through Culcairn. This contributed to higher Victorian market prices, particularly over 8 to 10 July, which appeared to flow through to higher prices in the southern STTMs. Other GPG in NSW along the EGP also increased the value of EGP supply, which was redirected back into the Victorian market on 9 July when the daily price peaked at $34.95/GJ.[19]

Several market participants reported that they or their customers were actively trading against the flexibility allowed in their long term gas supply contracts. Users were obtaining gas above their daily contract quantities where their maximum daily contract quantity was greater than their average daily quantity. This contract flexibility known as “load factor” allowed users to gain additional value from their gas supply contracts by avoiding high spot market prices and taking

[16] Baseload generation outages in southern markets affected generation assets in NSW and Victoria in early July. These included Eraring unit 1 (3-8 July), Mount Piper unit 1 (2-6 July) and Bayswater unit 2 (most of July) in NSW, and Loy Yang A unit 4 (5-11 July).

[17] The majority of Victorian GPG assets are located within the DTS and contribute to higher market demand (excluding Mortlake in the west and Bairnsdale in the east).

[18] Including the 5-9 July and 21-23 July gas days.

[19] The 6 am schedule price for 9 July reached $34.84/GJ, rising to $58.44/GJ by the 10 am schedule, with indicative price forecasts showing extremely high levels of price volatility resulting from 10% demand forecast sensitivities.

lower priced gas under contract. With a number of gas users nominating higher than average gas quantities under contract there was less gas available from producers to supply into spot markets.

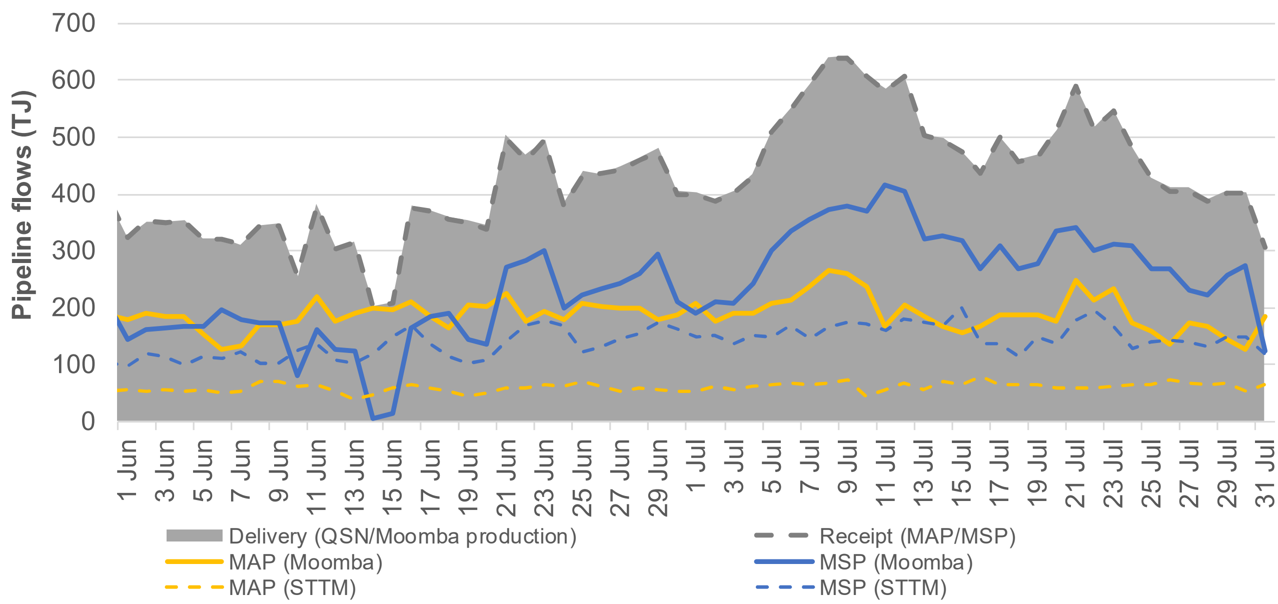
4.4 Limited but high priced deliveries of northern gas supply to South

Production levels in Queensland were up from previous years, particularly for July, with over 128.5 PJ of gas supplied from Roma production facilities, exceeding the July 2020 record of 125 PJ.

While flows south from Queensland on the Moomba to Sydney Pipeline (MSP) increased from previous months, the quantities being delivered to Victoria were limited on a number of days due to upstream supply requirements constraining the amount of gas which could be delivered through the Culcairn supply point to the Victorian DWGM.[20]

Gas flows south from Queensland across winter 2021 were significantly lower than previous years. While net flows south ranged around 6 to 10 PJ per month for winter 2019 and 2020, flows didn't exceed 7.2 PJ for July 2021 and were less than 4 PJ for both June and August 2021. Flows south were elevated over the first half of July, reducing from mid-July as southern market prices declined and Queensland Curtis LNG (QCLNG) concluded a month long planned maintenance outage (Figure 7) on 13 July.[21]

Figure 7 Pipeline flows south from Moomba[22]



Source: AER analysis using the Natural Gas Services Bulletin Board.

Note: MAP is the Moomba to Adelaide Pipeline, MSP is Moomba to Sydney Pipeline.

Winter export gas flows to Curtis Island (Queensland) have been higher than levels typically observed over winter in 2021. Pipeline flows delivering to the export facilities were sitting at their

[20] For example on 9 July injections into Victoria through Culcairn were limited by high deliveries into Sydney and gas powered generation usage in southern New South Wales.

[21] QCLNG maintenance planned from 15 June to 13 July.

[22] The Queensland/South Australia/New South Wales (QSN) link is a section of the South West Queensland Pipeline (SWQP) connecting Queensland gas supply to the Moomba to Adelaide Pipeline (MAP) and Moomba to Sydney Pipeline (MSP) in South Australia.

highest level to date for the month of July. In particular, the last half of July was unaffected by planned train maintenance outages which typically can occur in the Australian winter, aligned to avoid the Asian winter, and can free up gas for the domestic market.

High international LNG prices over July may have put upwards pressure on the price of gas supply from Queensland which despite high export demand, was brought south over July to fill domestic supply shortfalls.[23] East coast LNG producers may have been reluctant to sell to domestic spot markets unless domestic prices were high enough to allow a sale for value relative to international prices.[24]

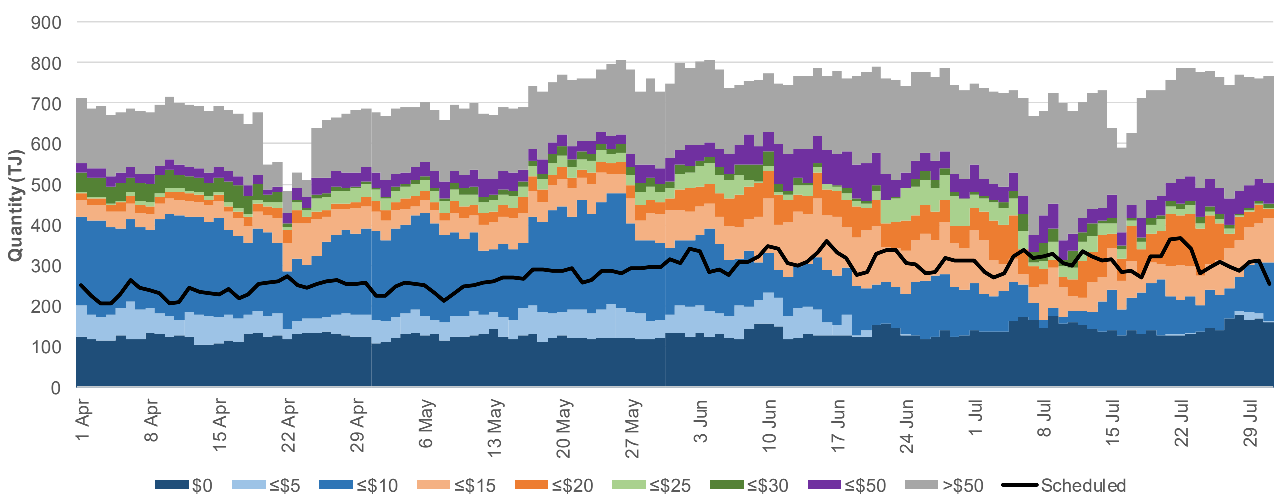
Above average temperatures for the summer period in the northern hemisphere have coincided with North East Asian prices trading at elevated levels across most of the second quarter and the beginning of third quarter of 2021.[25]

4.5 General bidding behaviour in Sydney and Adelaide

There was a general increase in the structure of offer prices from late May in Sydney, with the price of offered capacity rising alongside higher winter demand requirements from early July (Figure 8).

For Adelaide, the most significant change in offers occurred over a relatively short period in in early July (Figure 9).

Figure 8 Ex ante offer trend in the Sydney STTM



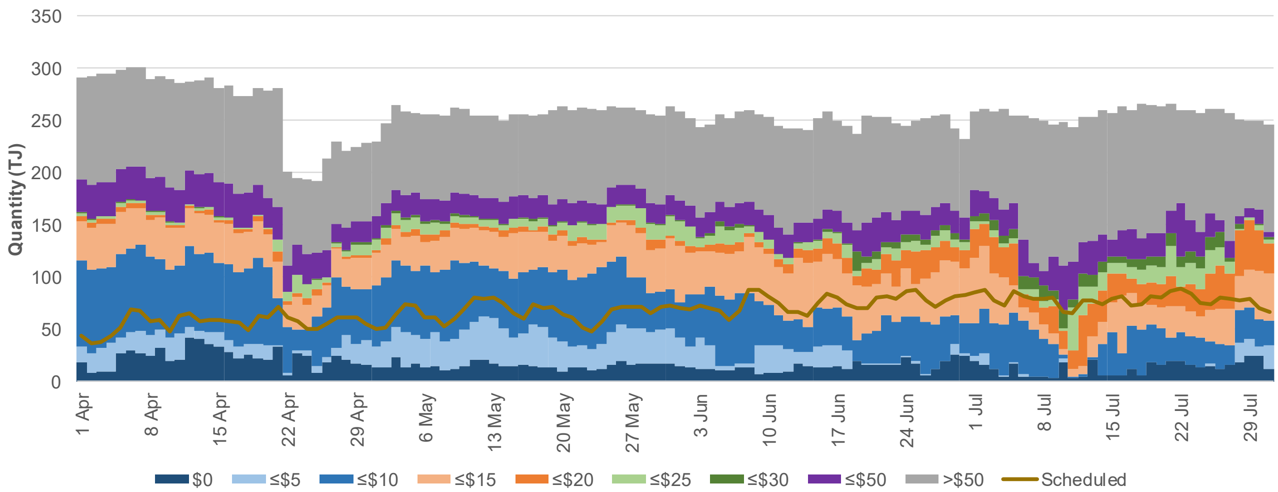
Source: AER analysis using STTM data.

[23] *AER, Wholesale Markets Quarterly, Q3 2021*

[24] This pricing dynamic is different to AER observations of East Coast LNG producers when they have been buying gas, including in September 2021, which is they have been buying gas from the domestic market significantly below the equivalent international LNG prices.

[25] *AER Wholesale Markets Quarterly Q3 2021*

Figure 9 Ex ante offer trend in the Adelaide STTM



Source: AER analysis using STTM data.

5 Analysis

Across the month of July, the D-1 price in the STTMs deviated from the D-2 forecast price by more than $7/GJ on a total of 9 occasions, triggering the AER significant price variation reporting thresholds. The majority of these deviations were due to a significant downward shift in the ex ante price following participants rebidding to provide additional supply to the market at lower prices, with just 2 instances of prices exceeding the $7/GJ due to higher ex ante prices (one in Sydney on 7 July and one in Adelaide on 9 July).

5.1 Sydney

With the exception of those on 7 July, all price variations above $7/GJ in magnitude were reduced prices for the ex ante schedule (as occurred on 7 days). There were a number of other days where there were price reductions of more than $4/GJ, but less than $7/GJ.

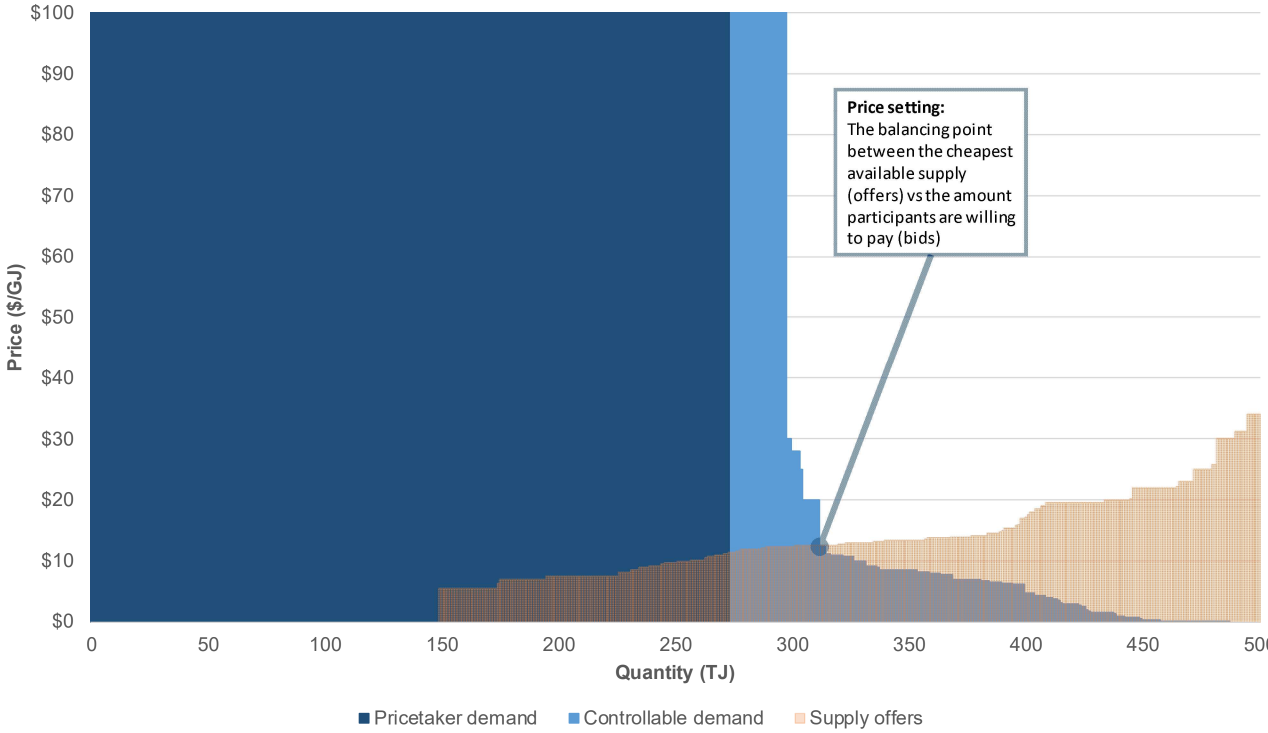
Price setting in the gas markets happens by matching the lowest priced supply offers against the highest valued demand quantities submitted by market participants. In Figure 11 below, supply offers are ordered from lowest prices on the left to highest prices on the right, with the cheapest supply being scheduled first. Conversely for demand, priority is given to participants' quantities that place a higher value on getting the gas, with bids ordered from highest prices on the left to lowest prices on the right.

Demand is divided into price taker demand (comprised of uncontrollable demand forecasts submitted by each of the individual participants), and controllable demand (for gas that will only be scheduled up to the price of a given bid). Price taker demand is considered at the highest priority in scheduling, with uncontrollable forecast quantities expected to be met regardless of the price. Uncontrollable demand, submitted via bids[26] is priced up to the market price cap of $400/GJ in the STTM.

Scheduled prices are set at the balancing point, where the cheapest gas supply can be provided to meet demand, up to the level participants are willing to pay (illustrated in Figure 10 below).

[26] Controllable demand bids can be submitted for delivery either inside the hub (the distribution network), or for delivery to upstream pipeline sources (referred to as backhaul). Backhaul demand is not included in price taker demand forecasts.

Figure 10 Sydney – 1 July, ex ante bidding/supply composition



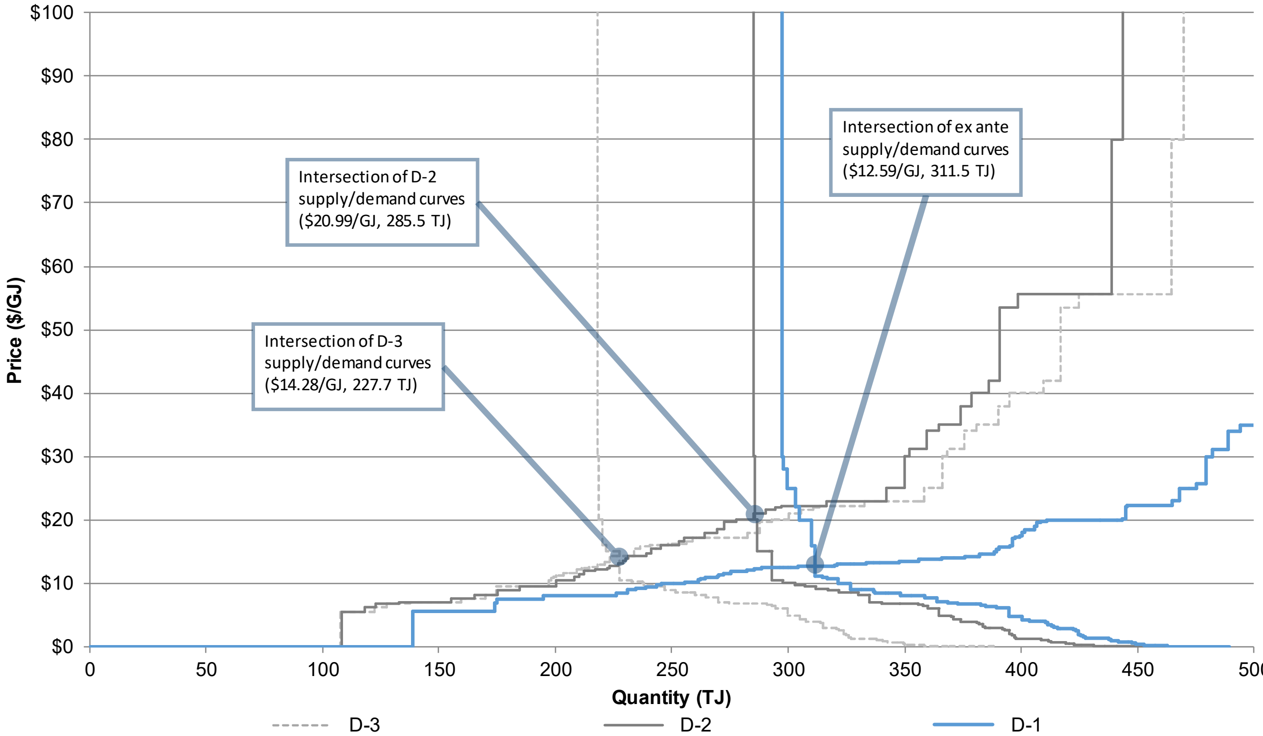
Source: AER analysis using STTM data.

5.1.1 Sydney STTM – 1 July

On 1 July, the variation between the D-2 price ($20.99/GJ) and D-1 price ($12.59/GJ) in Sydney was $8.40/GJ (Figure 11).

The higher D-2 price was the result of a significant demand increase, rising by 57.8 TJ due to higher participant demand forecasts (up 45.6 TJ) and rebidding of controllable withdrawal bids up to higher prices (leading to more offers being cleared at high prices). This led to prices increasing from $14.28/GJ at D-3 to $20.99/GJ in the D-2 schedule, despite relatively minor changes to offer prices for supply capacity above 265 TJ between the 2 provisional schedules (Figure 11).

Figure 11 Sydney – 1 July, D-2 provisional and ex ante bidding

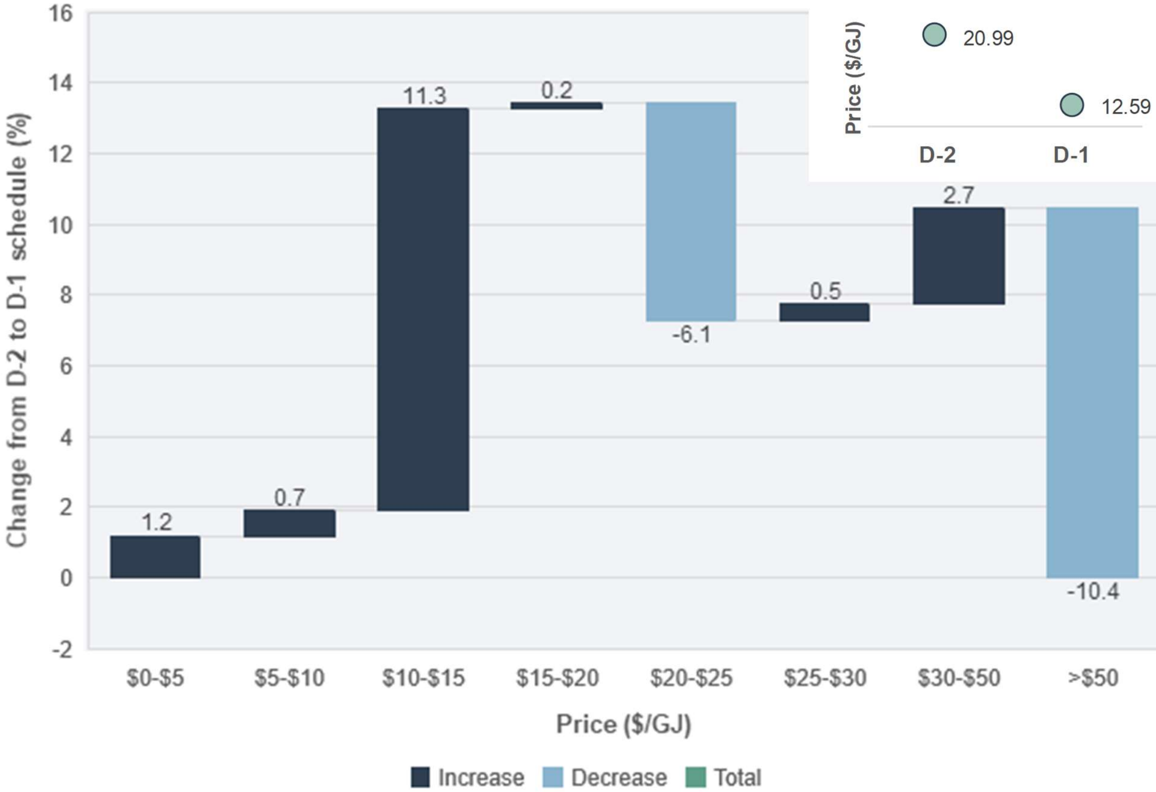


Source: AER analysis using STTM data.

On D-1, the forecast price reduced below the D-3 forecast despite a further demand increase as participant rebidding significantly flattened the supply curve, with participants collectively offering more than 400 TJ of supply capacity below $20/GJ in the ex ante schedule (Figure 12 and Figure 13). A large proportion of extra capacity was shifted to prices between $10/GJ and $15/GJ by exporter/producers, and in bands below $15/GJ by GPG gentailers (including additional capacity being offered – Figure 14).[27]

[27] Participants offered an additional 126.4 TJ of capacity in the ex ante schedule, with the majority of this capacity added by exporter/producers (37.9 TJ) and GPG gentailers (71.8 TJ). Ex ante offer quantities increased by 30.9 TJ at the floor price, 24.2 TJ between $5-10/GJ and 93 TJ between $10-15/GJ (with the latter increasing the proportion of $10-15/GJ offers available in the offer stack by 11.3%).

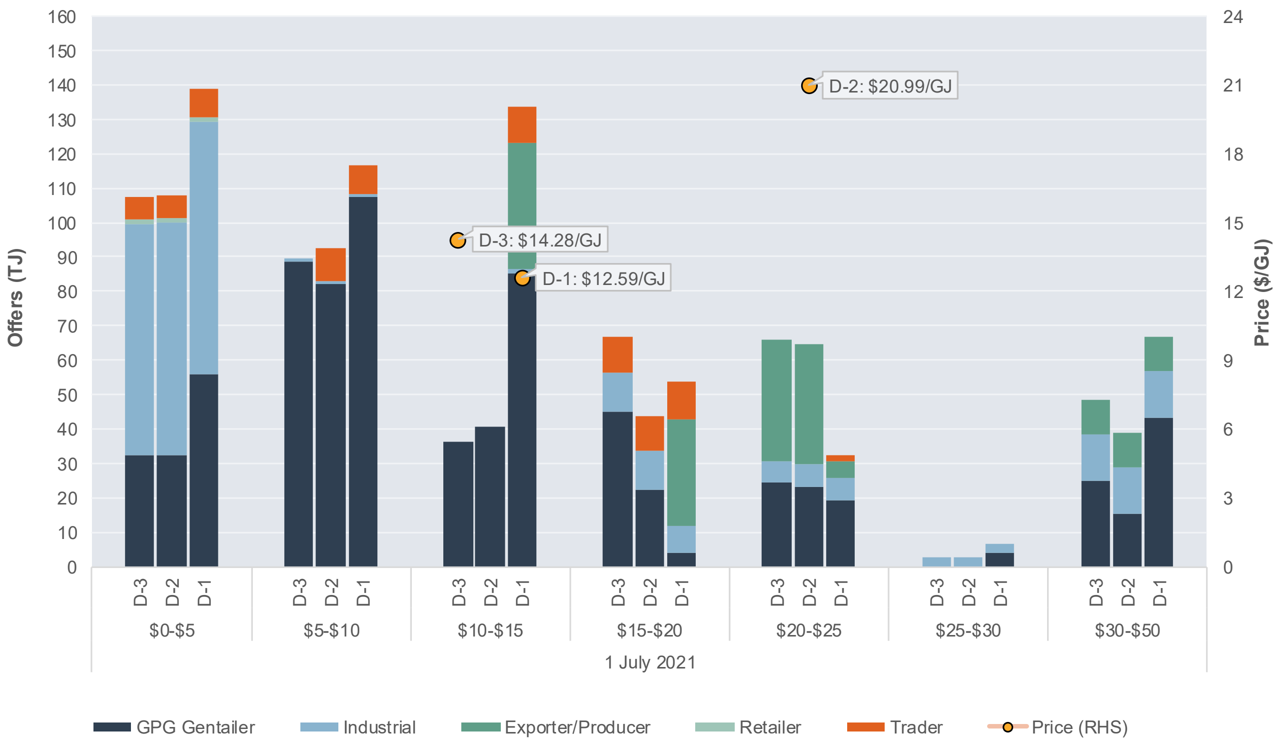
Figure 12 Change in gas offered between D-2 and D-1schedule in Sydney – 1 July 2021



Source: AER analysis using STTM data.

Note: The percentage change between the D-2 and D-1 schedule is an indication of how the composition of offers shifted between the D-2 and D-1 schedule in absolute terms. If the percentage is positive within a price band it implies that in the D-1 schedule more gas was offered compared to the total offering of gas in all the price bands compared to the D-2 schedule, while a negative percentage indicates the opposite.

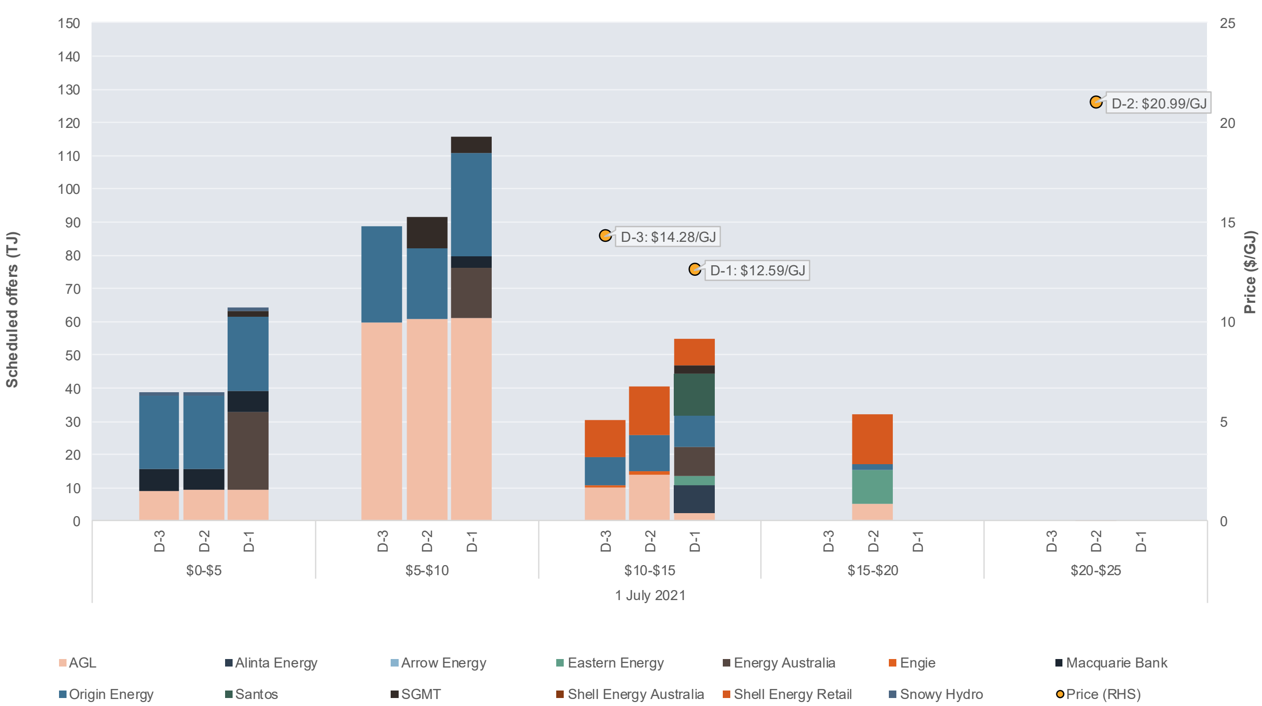
Figure 13 Participant offer stacks below $50 price bands in Sydney – 1 July 2021



Source: AER analysis using STTM data.

Note: Participant offers less than $50/GJ were grouped into price bands for the provisional and ex ante market schedules to show how different participants offered gas into the three market schedules.

Figure 14 Scheduled offers for GPG Gentailers, Exporter/Producers and Traders in Sydney – 1 July 2021



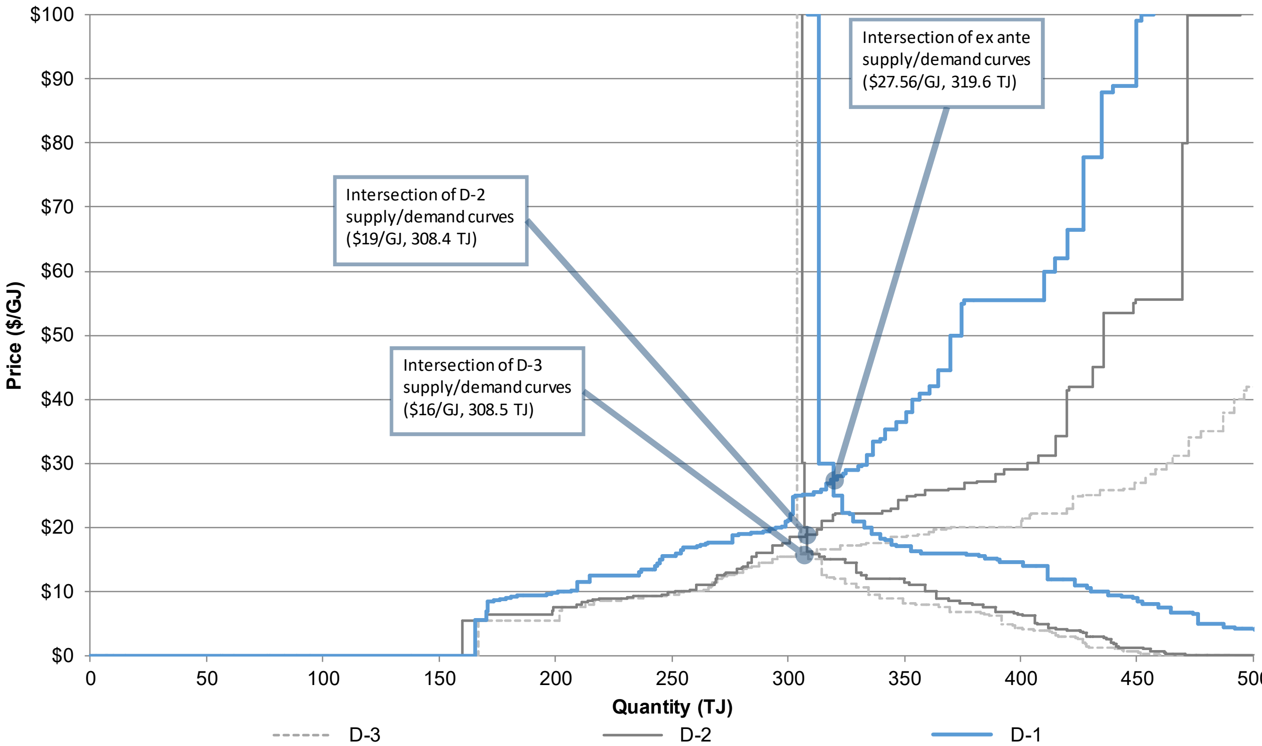
Source: AER analysis using STTM data.

Notes: The participant price bands are the actual price bands that were filled calculated for each of the market schedules.

5.1.2 Sydney STTM – 7 July

On 7 July, the variation between the D-2 price ($19/GJ) and D-1 price ($27.56/GJ) in Sydney was $8.56/GJ (Figure 15).

Figure 15 Sydney – 7 July, D-2 provisional and ex ante bidding



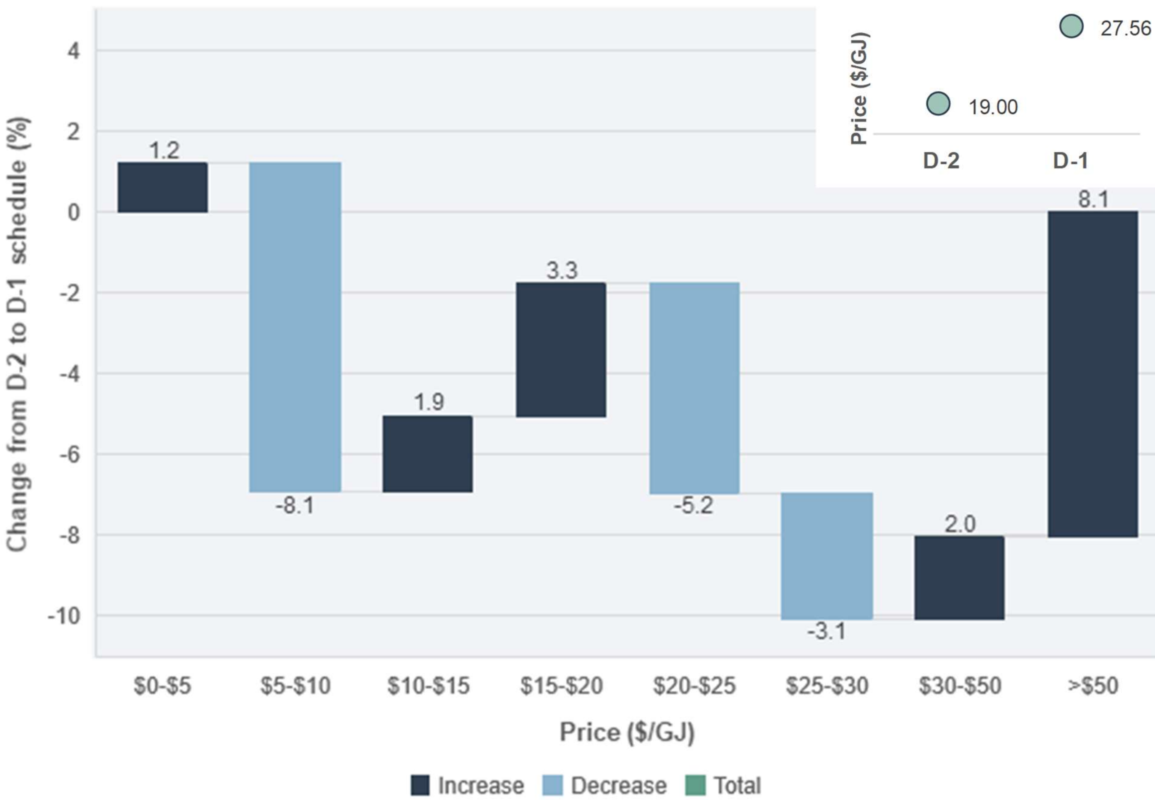
Source: AER analysis using STTM data.

From 6 July, weekday ex ante prices in Sydney began increasing above D-2 forecast prices (up $4/GJ). The D-2 forecast price in Sydney for the 7 July gas day had risen to $19/GJ in line with price increases across the markets. The ex ante price increased further, up $8.56/GJ to $27.56/GJ, with a large increase in gas offered above $50/GJ and a significant reduction to quantities offered at prices between $5/GJ and $10/GJ, and $20/GJ and $30/GJ (Figure 16). The vast majority of supply quantities shifted out of the lower price-band were being offered by GPG gentailers, with AGL and Origin offering more capacity around $20/GJ and $30/GJ, and $10/GJ and $20/GJ respectively (Figure 18).

In addition to the upward shift in the cost of supply offers, rebidding also shifted up the price of a number of controllable demand bids. These bids drove a notable increase to the demand cleared in the ex ante schedule. However, the additional demand cleared was not the main driver of the higher price.[28]

[28] Changing offers would have driven prices upwards of $25 at similar D-2 levels – see AER gas weekly report - https://www.aer.gov.au/wholesale-markets/performance-reporting/gas-report-4-10-july-2021

Figure 16 Change in gas offered between D-2 and D-1schedule in Sydney – 7 July 2021



Source: AER analysis using STTM data.

Note: The percentage change between the D-2 and D-1 schedule is an indication of how the composition of offers shifted between the D-2 and D-1 schedule in absolute terms. If the percentage is positive within a price band it implies that in the D-1 schedule more gas was offered compared to the total offering of gas in all the price bands compared to the D-2 schedule, while a negative percentage indicates the opposite.

Figure 17 Participant offer stacks below $50 price bands in Sydney – 7 July 2021

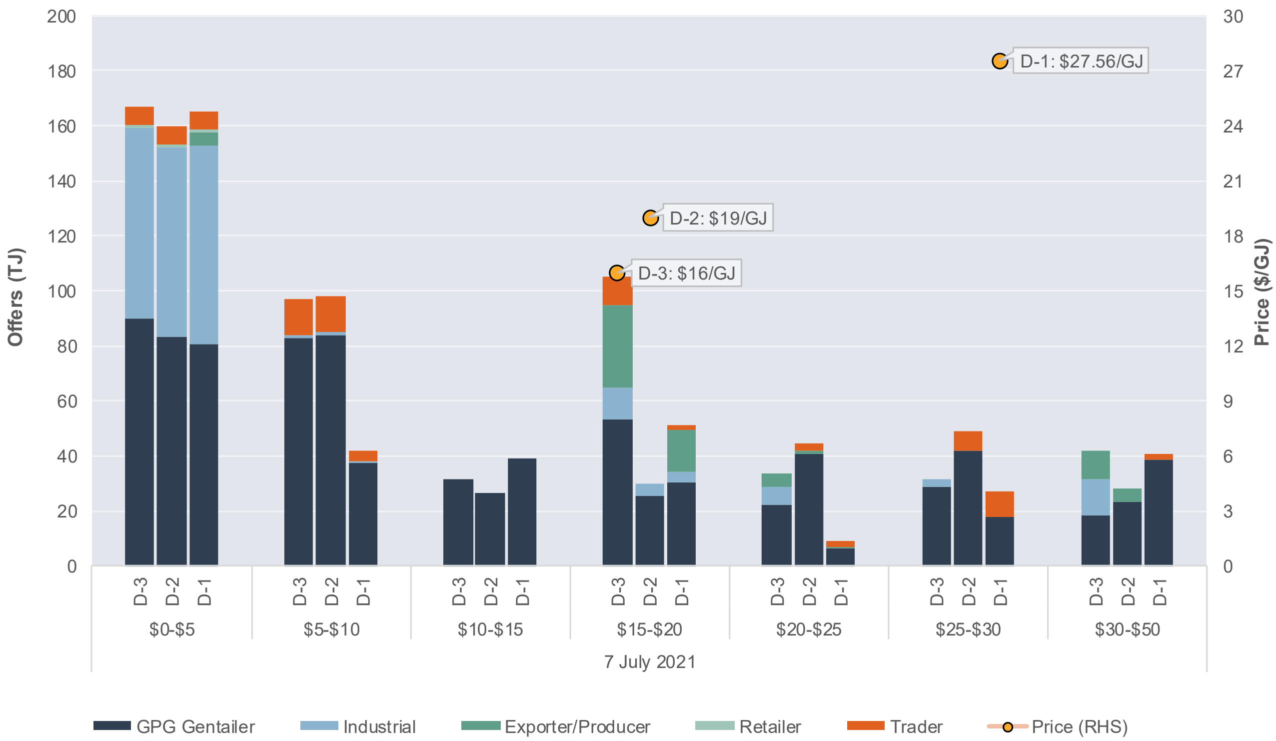
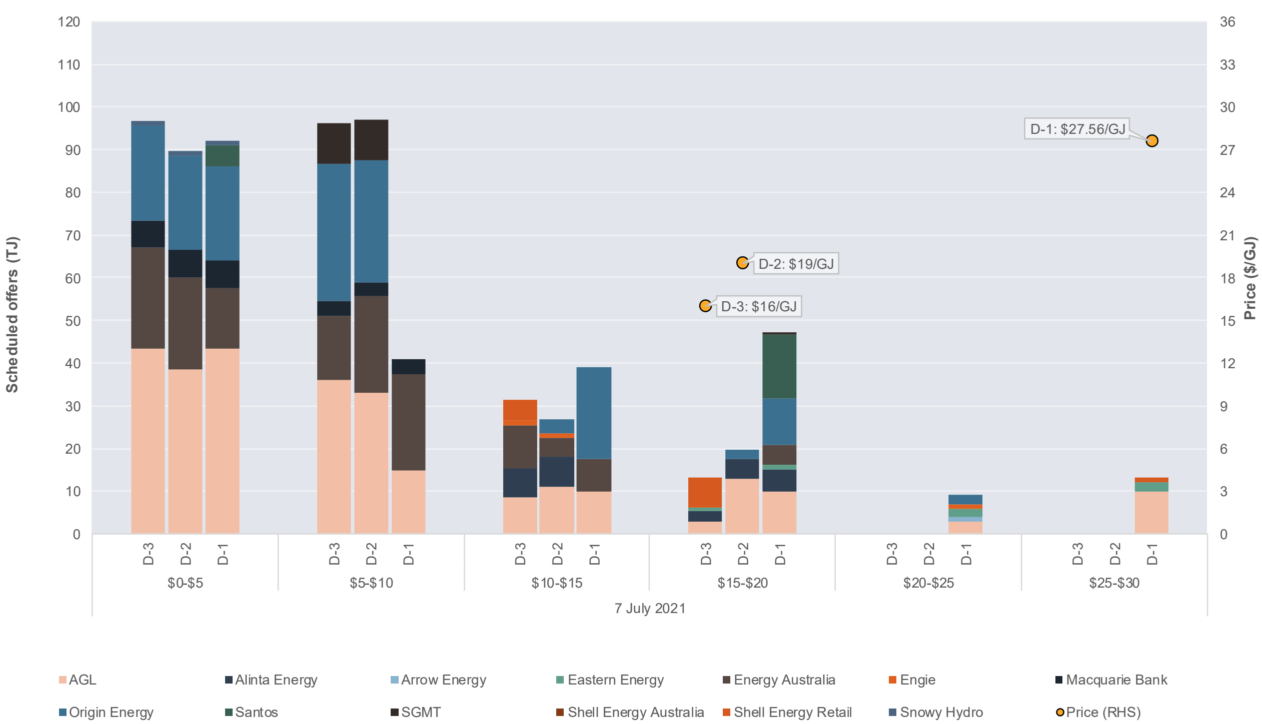


Figure 18 Scheduled offers for GPG Gentailers, Exporter/Producers and Traders in Sydney – 7 July 2021



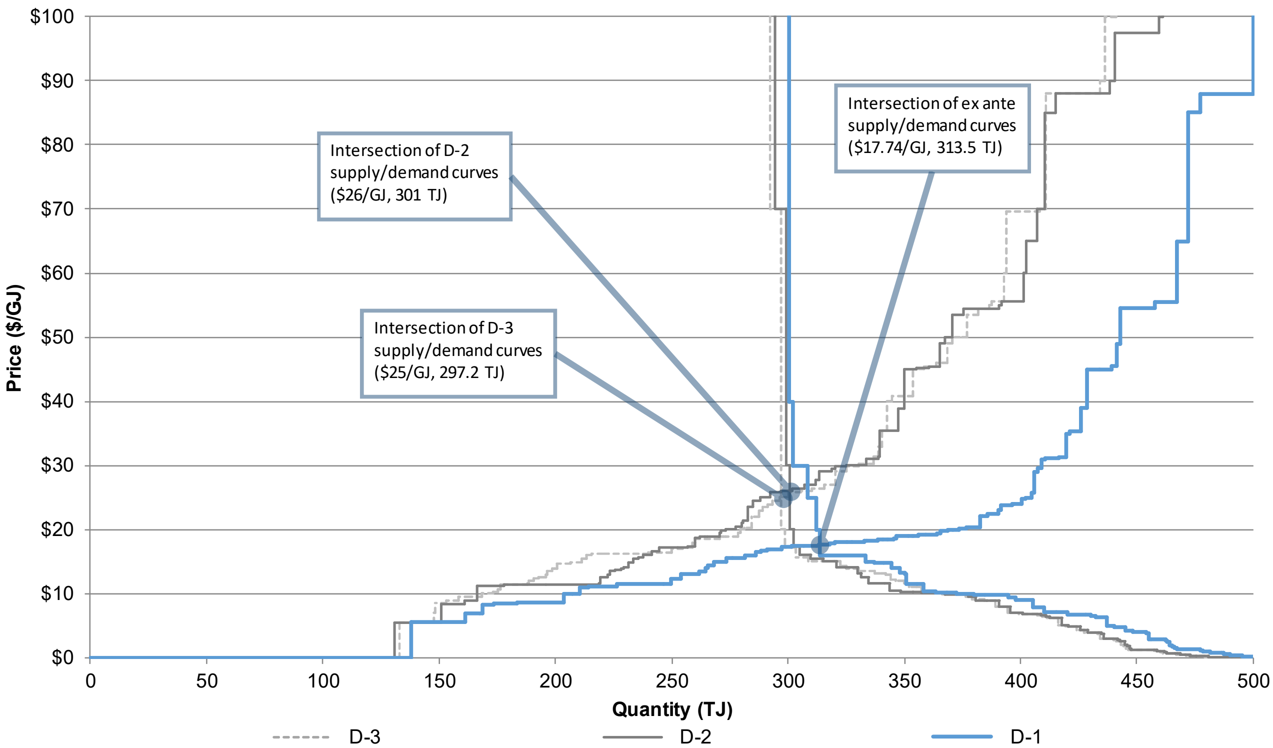
Source: AER analysis using STTM data.

Notes: The participant price bands are the actual price bands that were filled calculated for each of the market schedules.

5.1.3 Sydney STTM – 14 July

On 14 July the ex ante price reduced by $8.26/GJ from the D-2 forecast price of $26/GJ, to $17.74/GJ in the ex ante schedule (Figure 19). More gas was offered in the $5/GJ to $10/GJ and $15/GJ to $20/GJ price bands in the ex ante schedule with an overall reduction in gas offered at the price bands above $25/GJ.[29]

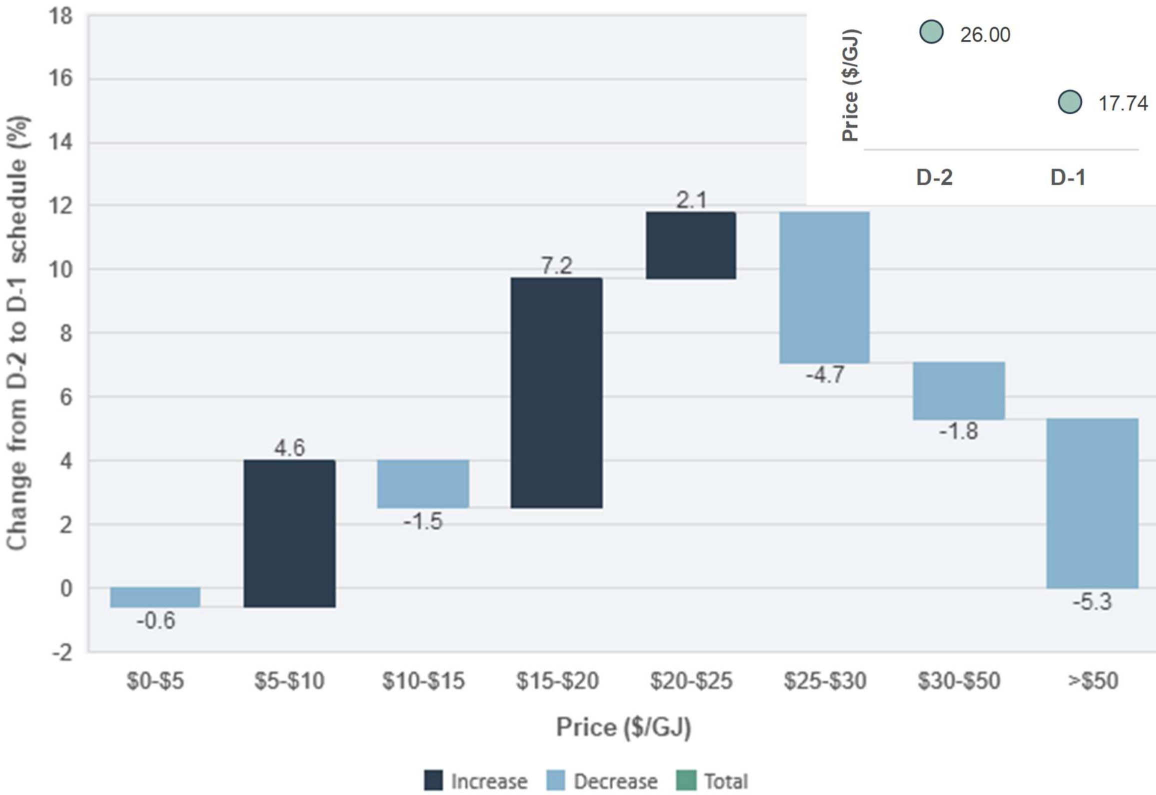
Figure 19 Sydney – 14 July, D-2 provisional schedule ex ante bidding



Source: AER analysis using STTM data.

[29] Capacity available between $5/GJ and $10/GJ, and $15/GJ and $20/GJ increased by 36.8 TJ and 56.4 TJ in the ex ante schedule respectively. This increased the proportions of gas offered in those price bands by 4.6% and 7.2% of total offers available, compared to the proportion of offers in the D-2 schedule.

Figure 20 Change in gas offered between D-2 and D-1schedule in Sydney – 14 July 2021



Source: AER analysis using STTM data.

Note: The percentage change between the D-2 and D-1 schedule is an indication of how the composition of offers shifted between the D-2 and D-1 schedule in absolute terms. If the percentage is positive within a price band it implies that in the D-1 schedule more gas was offered compared to the total offering of gas in all the price bands compared to the D-2 schedule, while a negative percentage indicates the opposite.

In the D-3 and D-2 schedules exporter/producers and trader participants only accounted for 10% of the gas offered below $50/GJ into the market, compared to almost 20% in the ex ante schedule. The majority of this gas was offered into the market at the lower prices, most notably the $5/GJ to $10/GJ and $15/GJ to $20/GJ price bands (Figure 21).

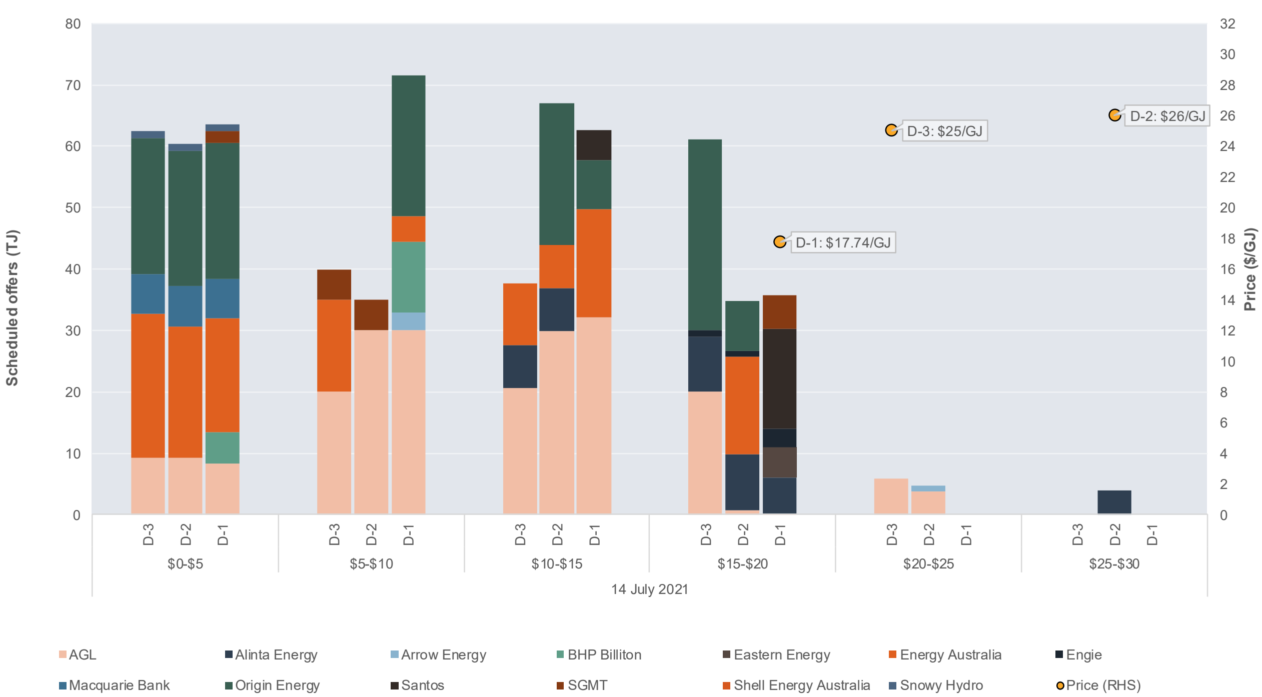
Santos and BHP only offered gas into the ex ante schedule, with Santos being scheduled 21.2 TJ in the $10/GJ to $15/GJ and $15/GJ to $20/GJ price bands, while BHP was scheduled 16.6 TJ in the $0/GJ to $5/GJ and $5/GJ to $10/GJ price bands (Figure 22). Similarly, Eastern Energy Buyers Group (EEBG), Strategic Gas Market Trading (SGMT) and Arrow Energy also saw more volumes scheduled in the ex ante schedule at lower price bands compared to the D-2 schedule.

Figure 21 Participant offer stacks below $50 price bands in Sydney – 14 July 2021

Source: AER analysis using STTM data.

Note: Participant offers less than $50/GJ were grouped into price bands for the provisional and ex ante market schedules to show how different participants offered gas into the three market schedules.

Figure 22 Scheduled offers for GPG Gentailers, Exporter/Producers and Traders in Sydney – 14 July 2021



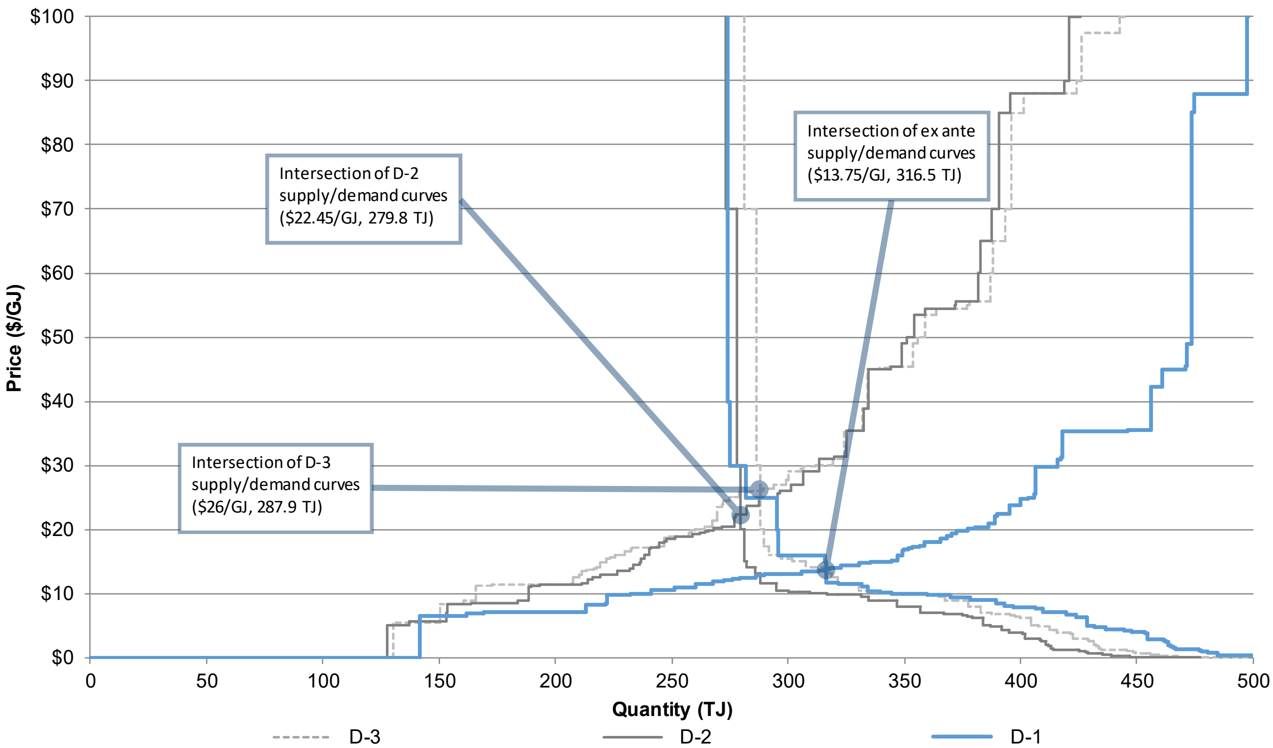
Source: AER analysis using STTM data.

Notes: The participant price bands are the actual price bands that were filled calculated for each of the market schedules.

5.1.4 Sydney STTM – 15 July

On 15 July, the variation between the D-2 price ($22.45/GJ) and D-1 price ($13.75/GJ) in Sydney was $8.70/GJ (Figure 23). This reduction in price followed a fall of $3.55/GJ from the D-3 to the D-2 schedules and was associated with a reduction in the quantity of gas offered above $50/GJ and an increase in quantity of gas offered below $15/GJ.

Figure 23 Sydney – 15 July, D-2 provisional and ex ante bidding



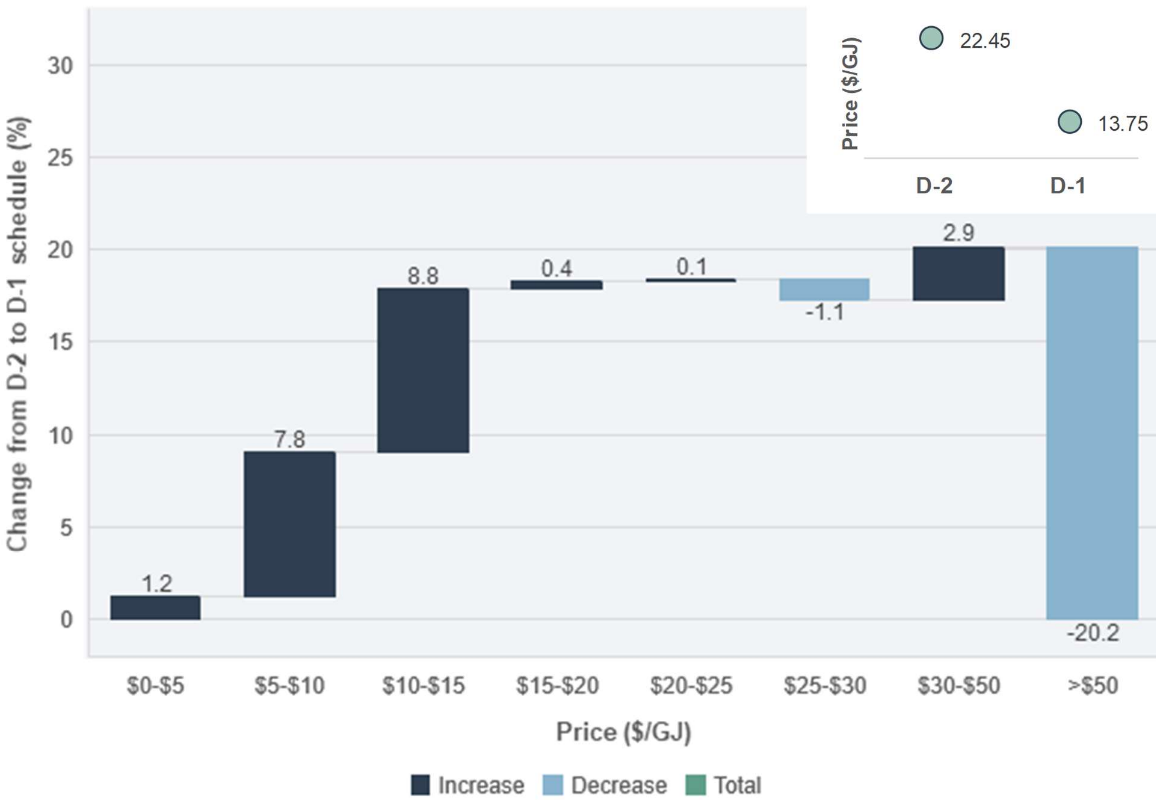
Source: AER analysis using STTM data.

The proportion of gas offered at prices above $50/GJ decreased by 22% between the D-2 and D-1 schedules. Available capacity offered in the $5/GJ to $10/GJ and $10/GJ to $15/GJ price bands increased by 48.4 TJ and 55.1 TJ, increasing the proportion of offers in those bands by 7.8% and 8.8% respectively in the ex ante schedule (Figure 24).

The majority of the additional capacity below $15/GJ was offered into the market by exporter/producers and GPG gentailers with some contribution from traders and industrials (Figure 25). In particular Santos, BHP and AGL Energy had significant additional quantities of gas scheduled in the ex ante schedule compared to the provisional schedules (Figure 26).

Some traders and suppliers were able to use the DAA to supply additional gas into the ex ante schedule. Participants won capacity at the Culcairn trade point, and on the EGP and MSP, allowing incremental quantities of gas to be supplied to southern markets.

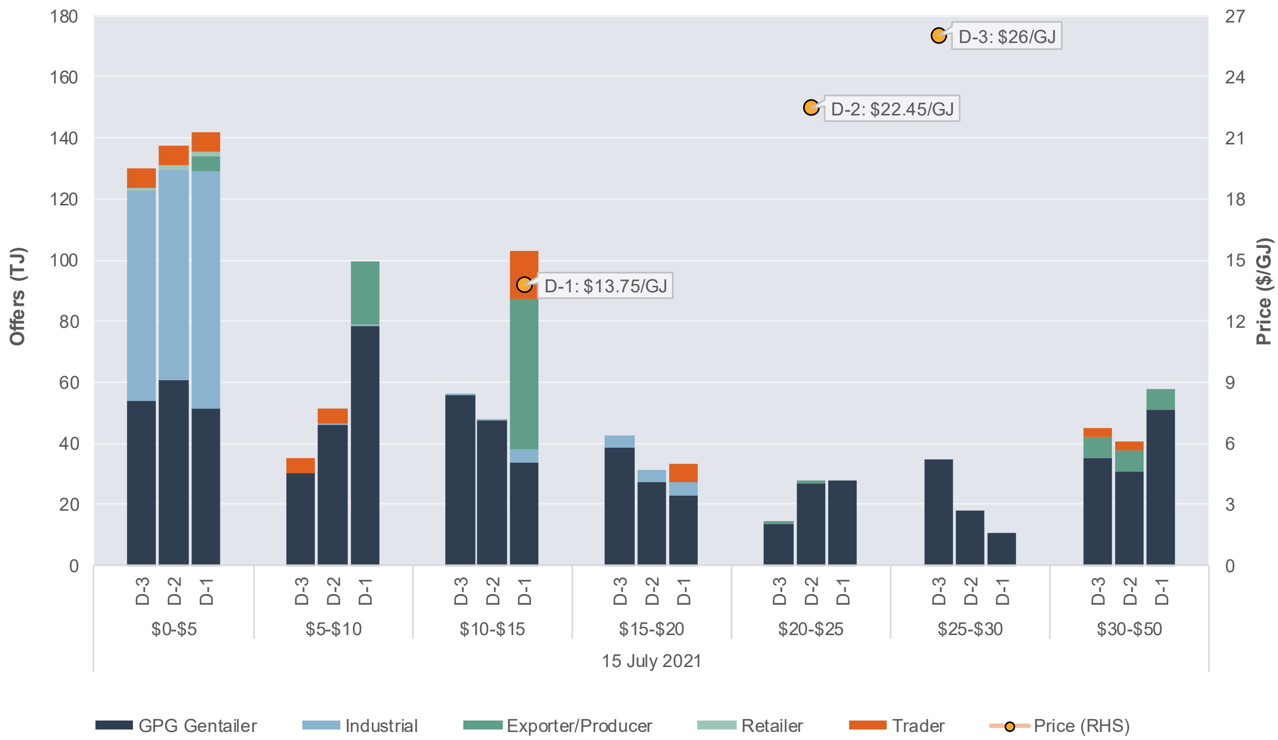
Figure 24 Change in gas offered between D-2 and D-1schedule in Sydney – 15 July 2021



Source: AER analysis using STTM data.

Note: The percentage change between the D-2 and D-1 schedule is an indication of how the composition of offers shifted between the D-2 and D-1 schedule in absolute terms. If the percentage is positive within a price band it implies that in the D-1 schedule more gas was offered compared to the total offering of gas in all the price bands compared to the D-2 schedule, while a negative percentage indicates the opposite.

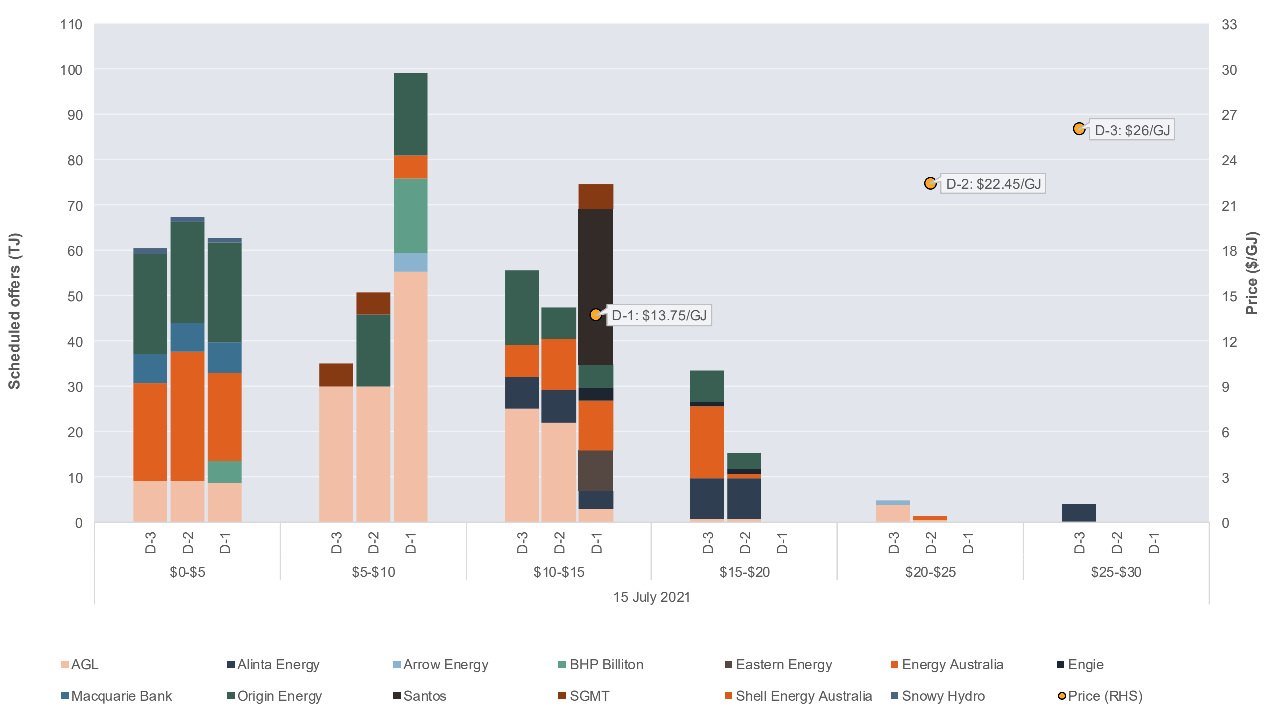
Figure 25 Participant offer stacks below $50 price bands in Sydney – 15 July 2021



Source: AER analysis using STTM data.

Note: Participant offers less than $50/GJ were grouped into price bands for the provisional and ex ante market schedules to show how different participants offered gas into the three market schedules.

Figure 26 Scheduled offers for GPG Gentailers, Exporter/Producers and Traders in Sydney – 15 July 2021



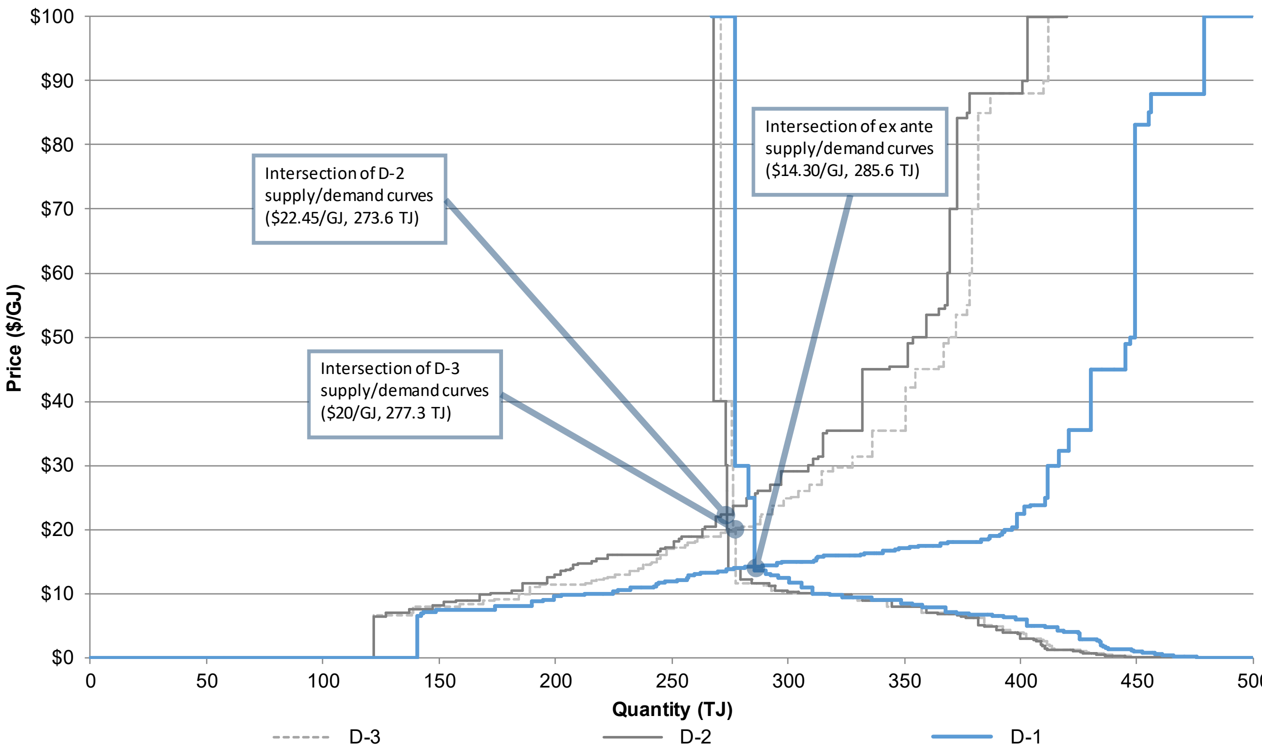
Source: AER analysis using STTM data.

Notes: The participant price bands are the actual price bands that were filled calculated for each of the market schedules.

5.1.5 Sydney STTM – 17 July

On 17 July, the variation between the D-2 price ($22.45/GJ) and D-1 price ($14.30/GJ) in Sydney was $8.15/GJ (Figure 27). Capacity available below $20/GJ increased by 132.3 TJ due to rebidding in the ex ante schedule, with the majority of offers shifted to prices between $10/GJ and $15/GJ.[30]

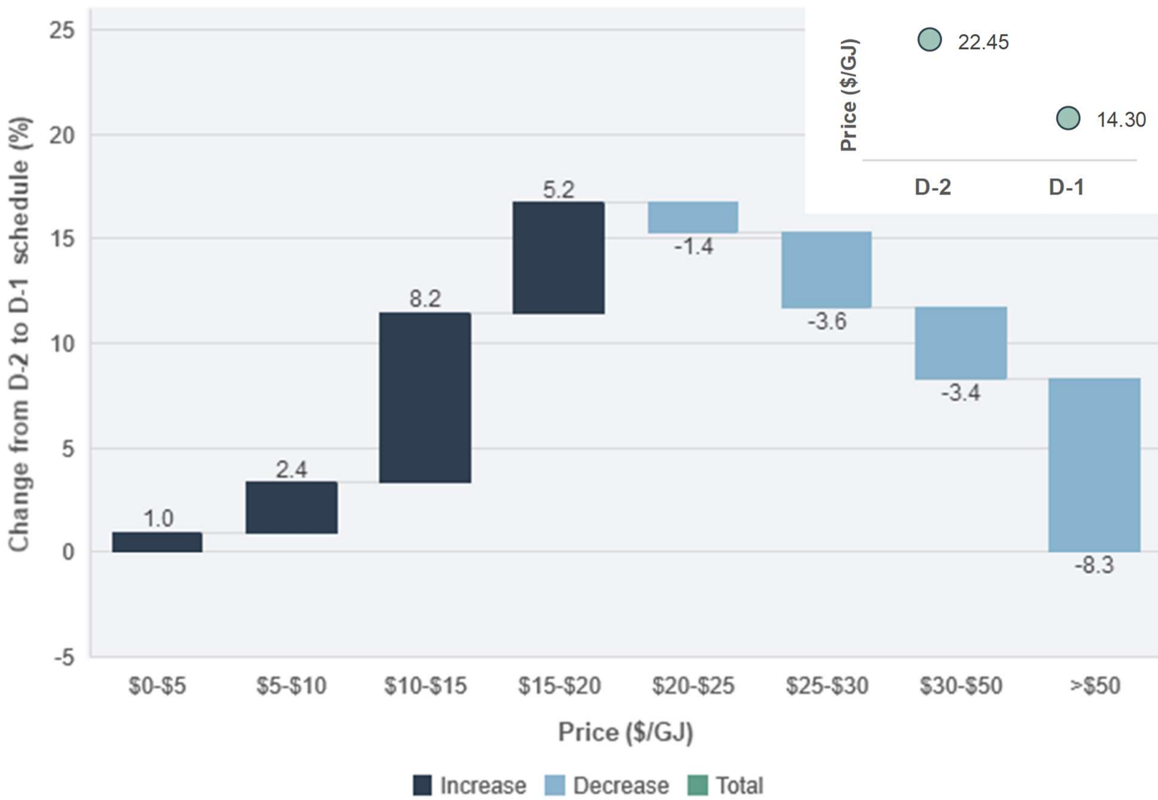
Figure 27 Sydney – 17 July, D-2 provisional and ex ante bidding



Source: AER analysis using STTM data.

[30] Capacity available below $10/GJ increased by 39.7 TJ (making up 70% of capacity available in the ex ante offer stack, increasing the proportion of offers available in that range by 3.4% from the D-2 schedule). Offers at $10-15/GJ and $15-20/GJ increased by 54.8 TJ (increasing the proportion of total $10-15/GJ offers by 8.2%) and 37.8 TJ (increasing the proportion of total $15-20/GJ offers by 5.2%).

Figure 28 Change in gas offered between D-2 and D-1schedule in Sydney – 17 July 2021



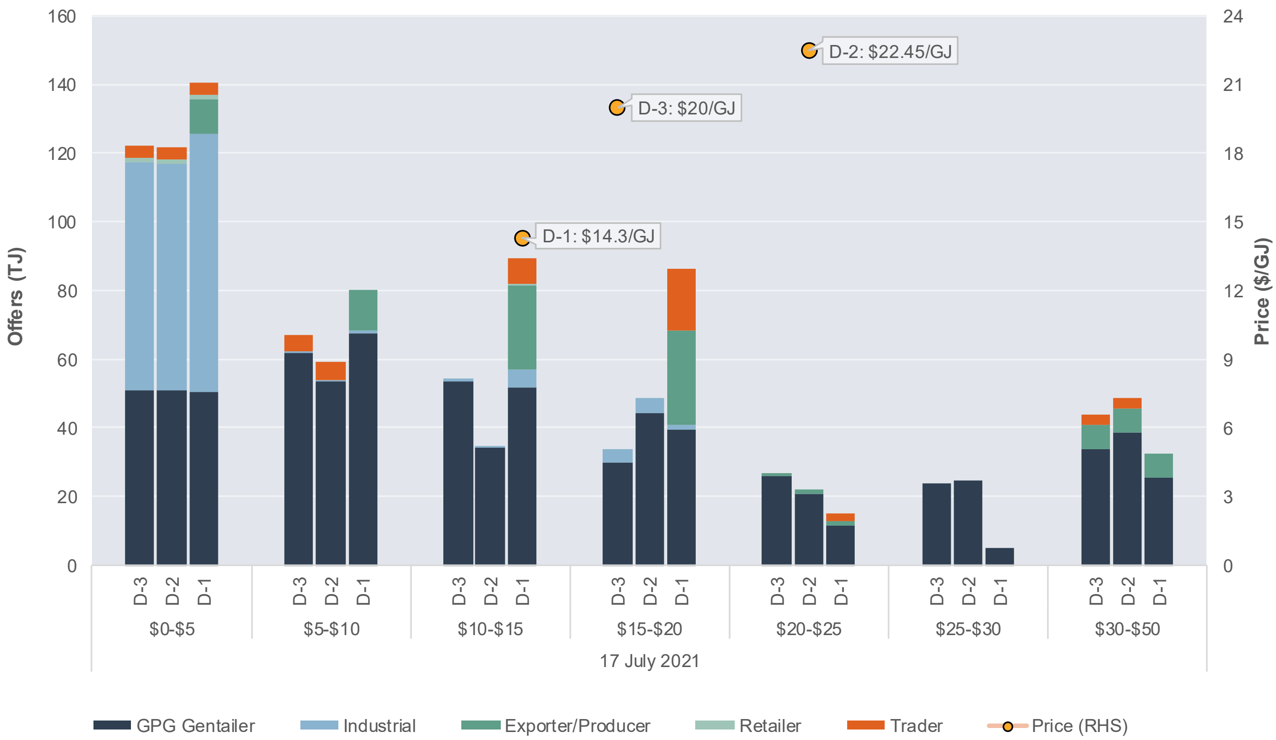
Source: AER analysis using STTM data.

Note: The percentage change between the D-2 and D-1 schedule is an indication of how the composition of offers shifted between the D-2 and D-1 schedule in absolute terms. If the percentage is positive within a price band it implies that in the D-1 schedule more gas was offered compared to the total offering of gas in all the price bands compared to the D-2 schedule, while a negative percentage indicates the opposite.

Exporter/Producers offered additional gas into the ex ante schedule below $20/GJ with the majority of the additional gas offered in the $10/GJ to $20/GJ range (Figure 29). The remainder of the increased ex ante offers at lower prices came from GPG gentailers and traders.

The bulk of the additional gas scheduled in the ex ante schedule relative to the D-3 and D-2 schedules was supplied by Santos, BHP and Esso (Figure 30). Traders made gas available to be scheduled ex ante after winning capacity in the DAA. Supply from retailers Shell, Alinta Energy and AGL Energy was displaced by the supply from producers and traders, leading to less of their gas being scheduled ex ante.

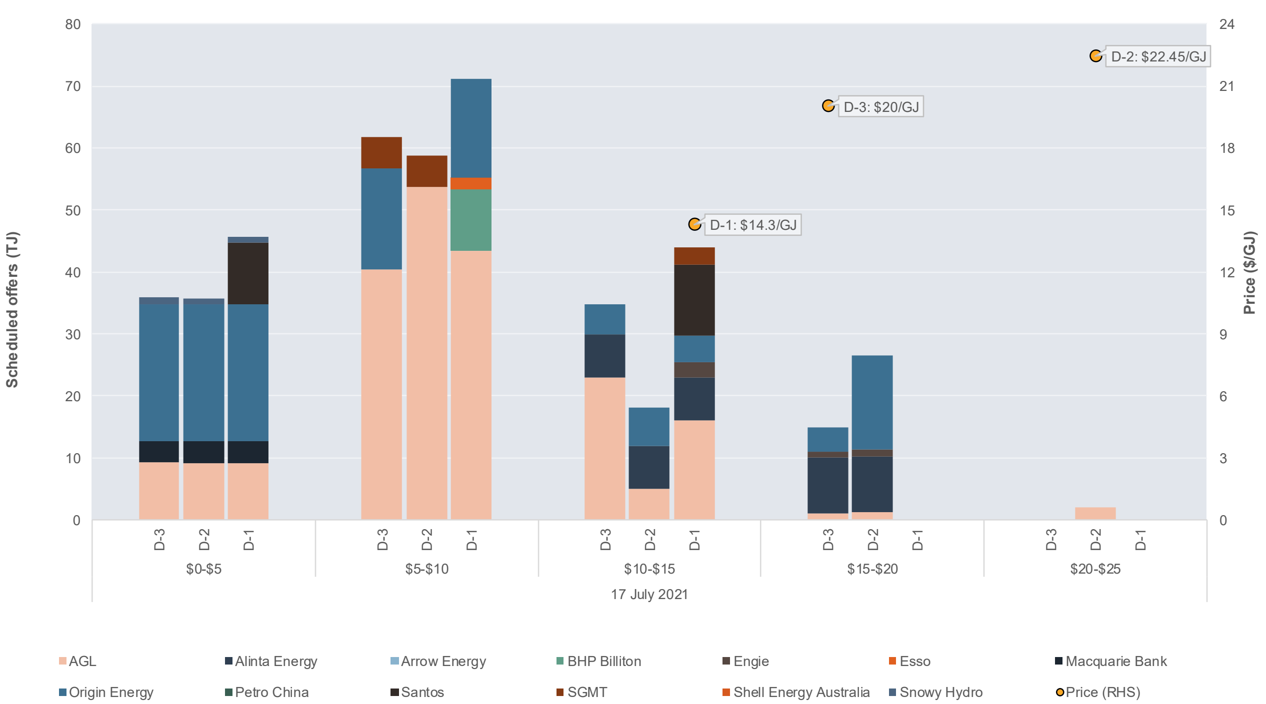
Figure 29 Participant offer stacks below $50 price bands in Sydney – 17 July 2021



Source: AER analysis using STTM data.

Note: Participant offers less than $50/GJ were grouped into price bands for the provisional and ex ante market schedules to show how different participants offered gas into the three market schedules.

Figure 30 Scheduled offers for GPG Gentailers, Exporter/Producers and Traders in Sydney – 17 July 2021



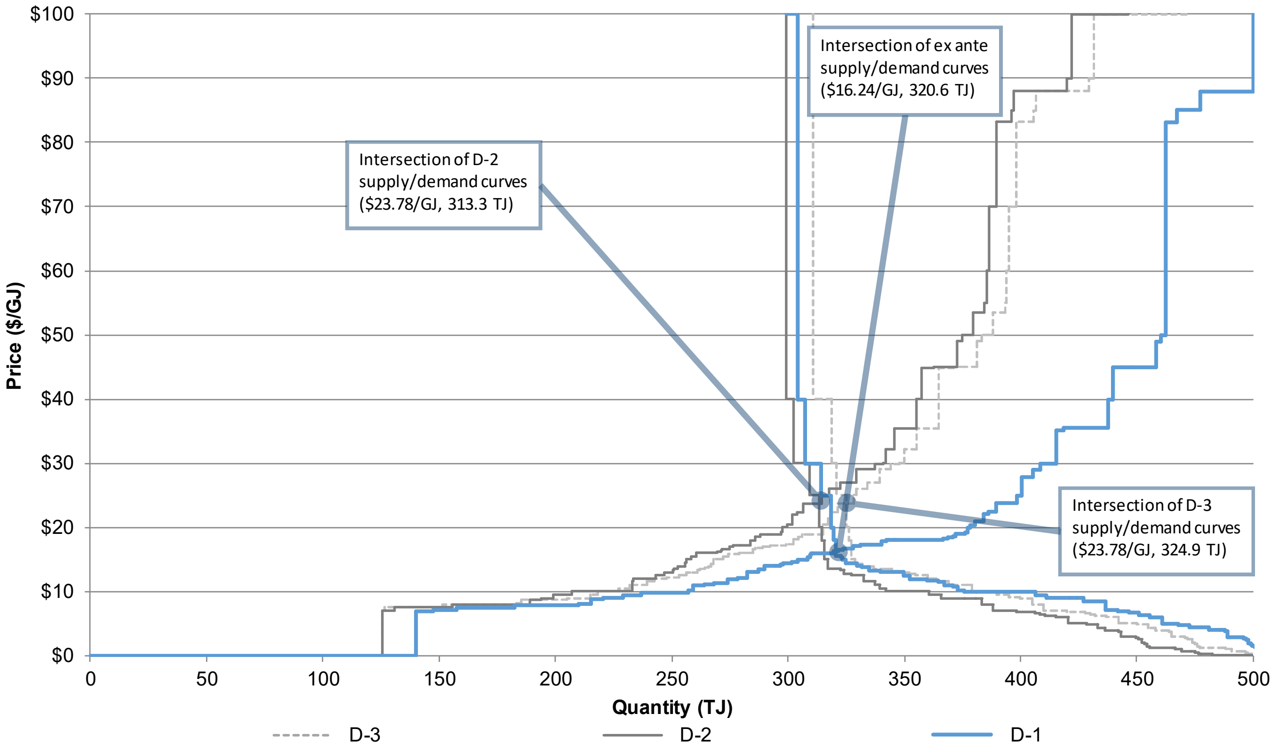
Source: AER analysis using STTM data.

Notes: The participant price bands are the actual price bands that were filled calculated for each of the market schedules.

5.1.6 Sydney STTM – 19 July

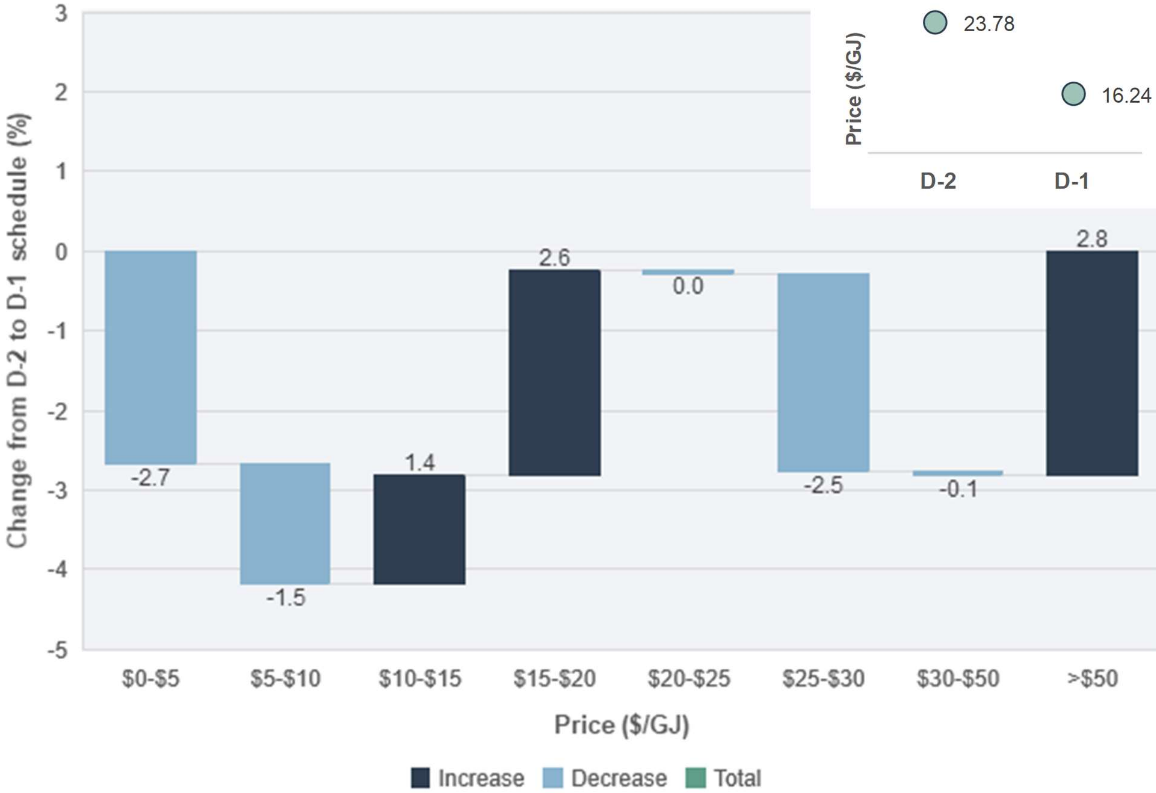
On 19 July, the variation between the D-2 price ($23.78/GJ) and D-1 price ($16.24/GJ) in Sydney was $7.54/GJ (Figure 31). In the D-1 schedule 156.7 TJ of additional capacity was offered compared to the D-2 schedule. This additional capacity was offered across a range of prices, with the exception of the $25/GJ to $30/GJ band (Figure 32).

Figure 31 Sydney – 19 July, D-2 provisional and ex ante bidding



Source: AER analysis using STTM data.

Figure 32 Change in gas offered between D-2 and D-1 schedule in Sydney – 19 July 2021



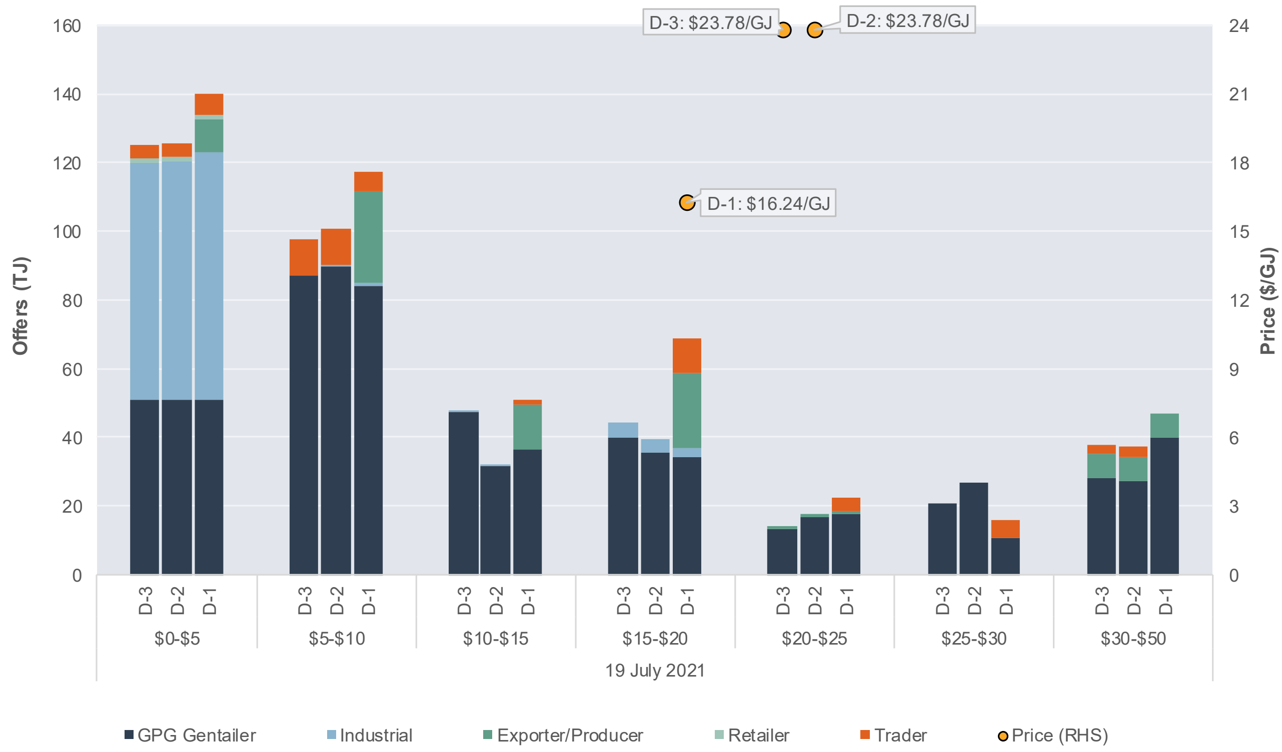
Source: AER analysis using STTM data.

Note: The percentage change between the D-2 and D-1 schedule is an indication of how the composition of offers shifted between the D-2 and D-1 schedule in absolute terms. If the percentage is positive within a price band it implies that in the D-1 schedule more gas was offered compared to the total offering of gas in all the price bands compared to the D-2 schedule, while a negative percentage indicates the opposite.

Controllable demand increased by 7.3 TJ due to backhaul on the EGP while the level of price taker demand remained stable. The actual proportion of offers in the $0/GJ to $10/GJ price band decreased in the D-1 schedule relative to the D-2 schedule as offer quantities between $0/GJ and $10/GJ in the D-2 schedule made up a large proportion of the offer stack with over 225 TJ of gas offered (Figure 33).

The majority of the lower cost supply in the D-1 schedule was offered by exporter/producers. Of these, Santos and BHP were the largest contributors and Esso also made a contribution (Figure 34). Less supply from major retailers was scheduled ex ante compared to the D-3 and D-2 schedule and less supply was scheduled from traders consistent with their DAA outcomes.

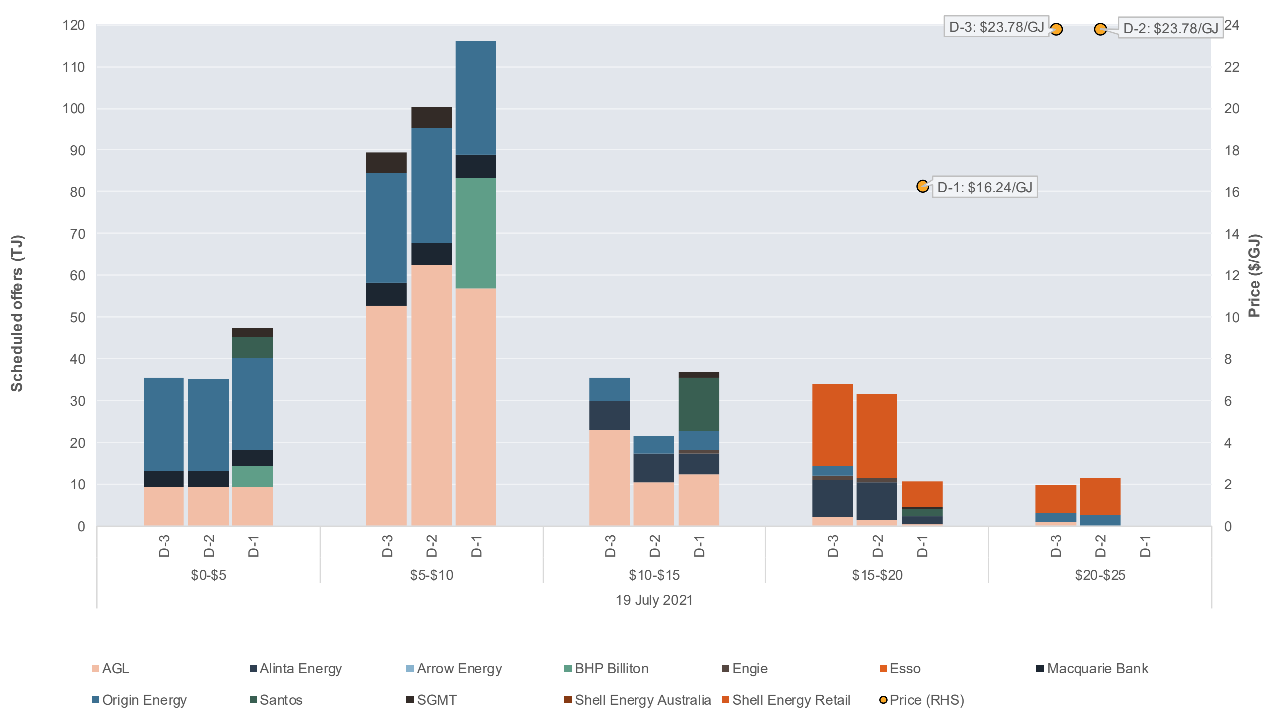
Figure 33 Participant offer stacks up to $50 price bands in Sydney – 19 July 2021



Source: AER analysis using STTM data.

Note: Participant offers less than $50/GJ were grouped into price bands for the provisional and ex ante market schedules to show how different participants offered gas into the three market schedules.

Figure 34 Scheduled offers for GPG Gentailers, Exporter/Producers and Traders in Sydney – 19 July 2021



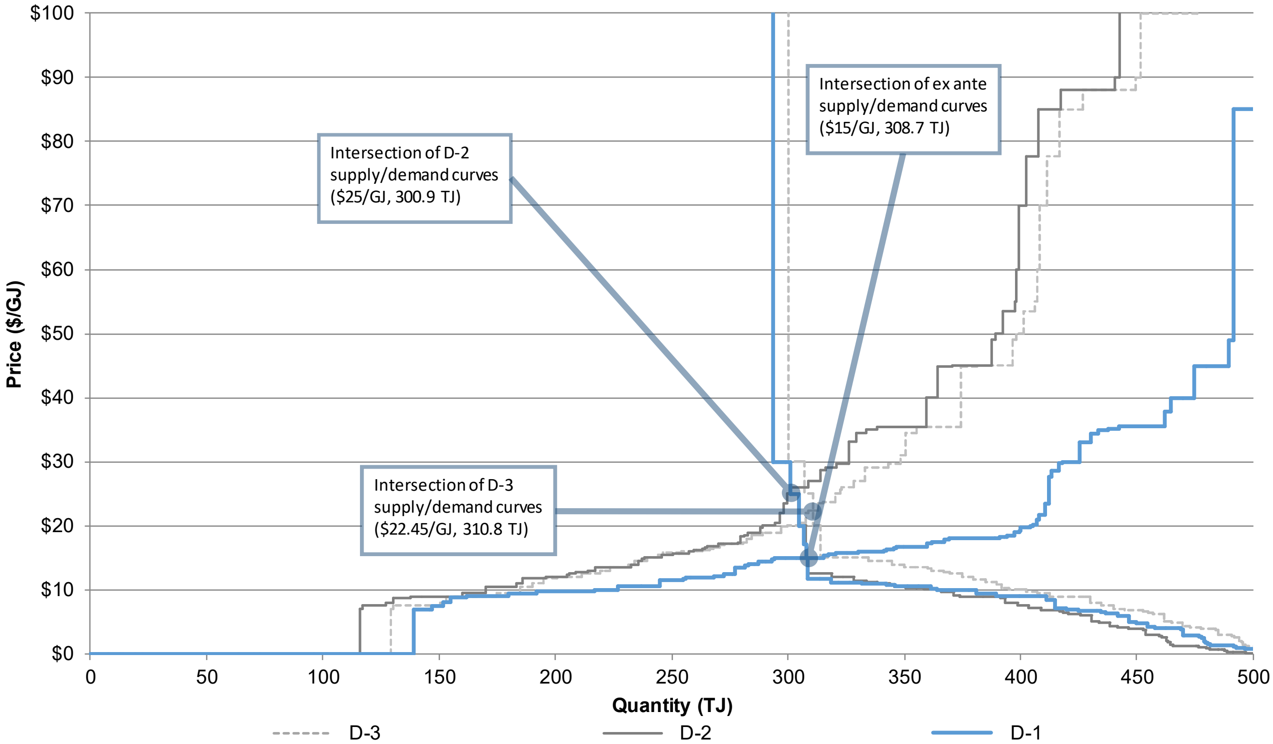
Source: AER analysis using STTM data.

Notes: The participant price bands are the actual price bands that were filled calculated for each of the market schedules.

5.1.7 Sydney STTM – 26 July

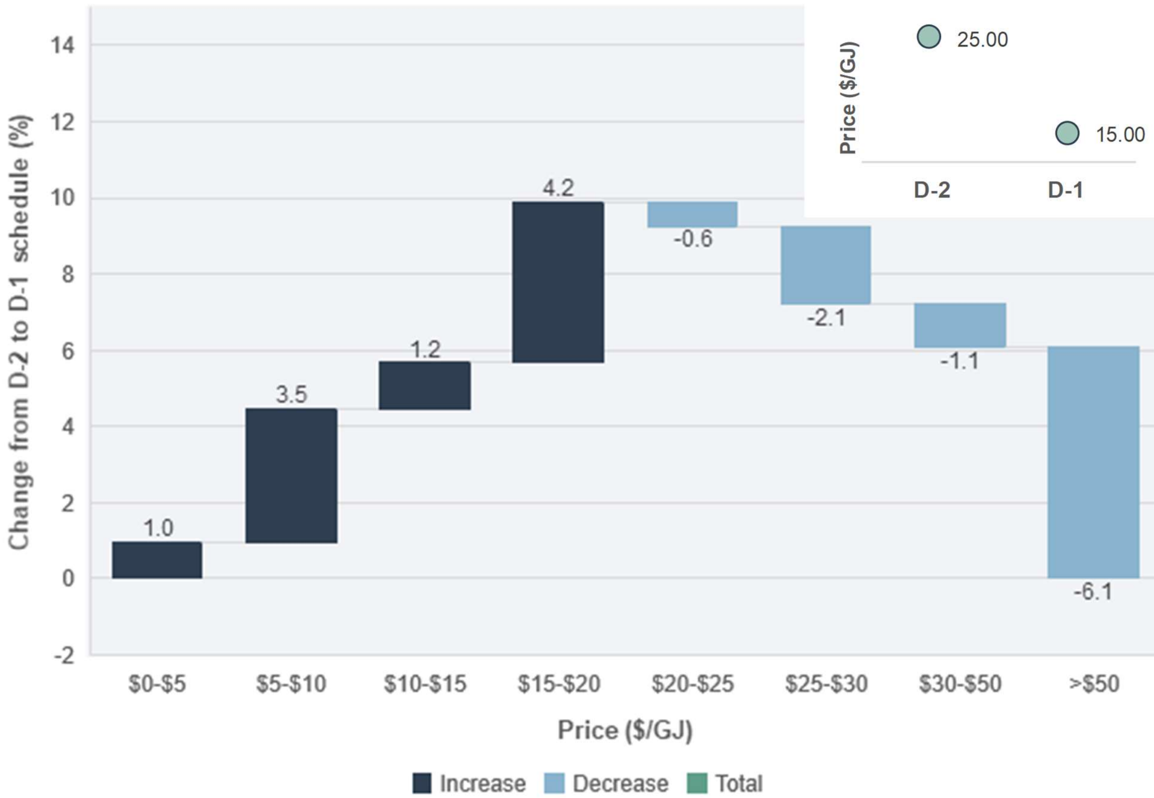
On 26 July, the variation between the D-2 price ($25/GJ) and D-1 price ($15/GJ) in Sydney was $10/GJ (Figure 35). The gas price increased in the D-2 schedule from $22.45/GJ in the D-3 schedule due to a reduction in the quantity of gas offered by exporter/producers and GPG gentailers. Offers increased by 90.8 TJ in the D-1 schedule and there was a reduction in the quantity of gas offered above $50/GJ of 8.5 TJ (Figure 36).

Figure 35 Sydney – 26 July, D-2 provisional and ex ante bidding



Source: AER analysis using STTM data.

Figure 36 Change in gas offered between D-2 and D-1schedule in Sydney – 26 July 2021

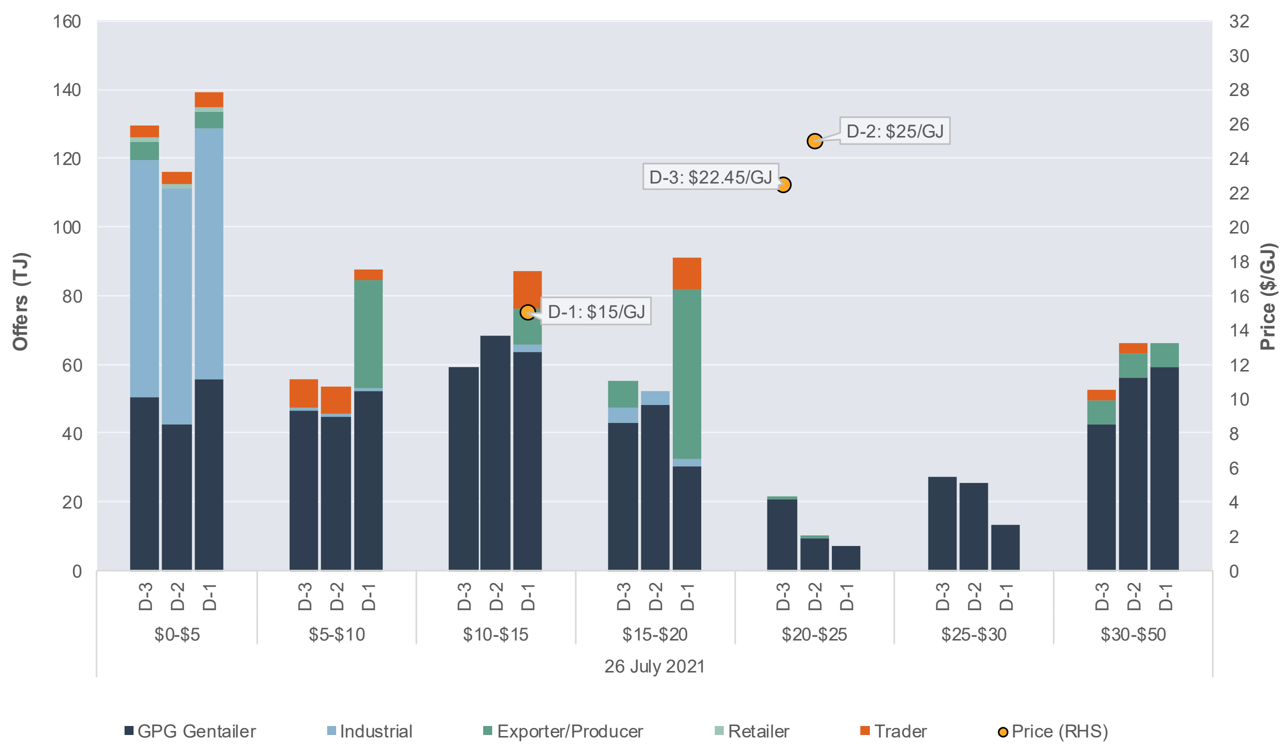


Source: AER analysis using STTM data.

Note: The percentage change between the D-2 and D-1 schedule is an indication of how the composition of offers shifted between the D-2 and D-1 schedule in absolute terms. If the percentage is positive within a price band it implies that in the D-1 schedule more gas was offered compared to the total offering of gas in all the price bands compared to the D-2 schedule, while a negative percentage indicates the opposite.

Exporter/producers were the largest suppliers of additional gas into the D-1 schedule with Bass Strait gas (BHP) being the most significant contributor (Figure 37 and Figure 38). Both traders and producers sourced transport capacity in the DAA to supply gas into the ex ante schedule. As with previous days of significant price variation, gas supply from a number of retailers (Shell, EnergyAustralia, Alinta Energy and AGL Energy) was reduced in the ex ante schedule relative to the D-3 and D-2 schedules due to being displaced by gas supply from exporter/producers and traders.

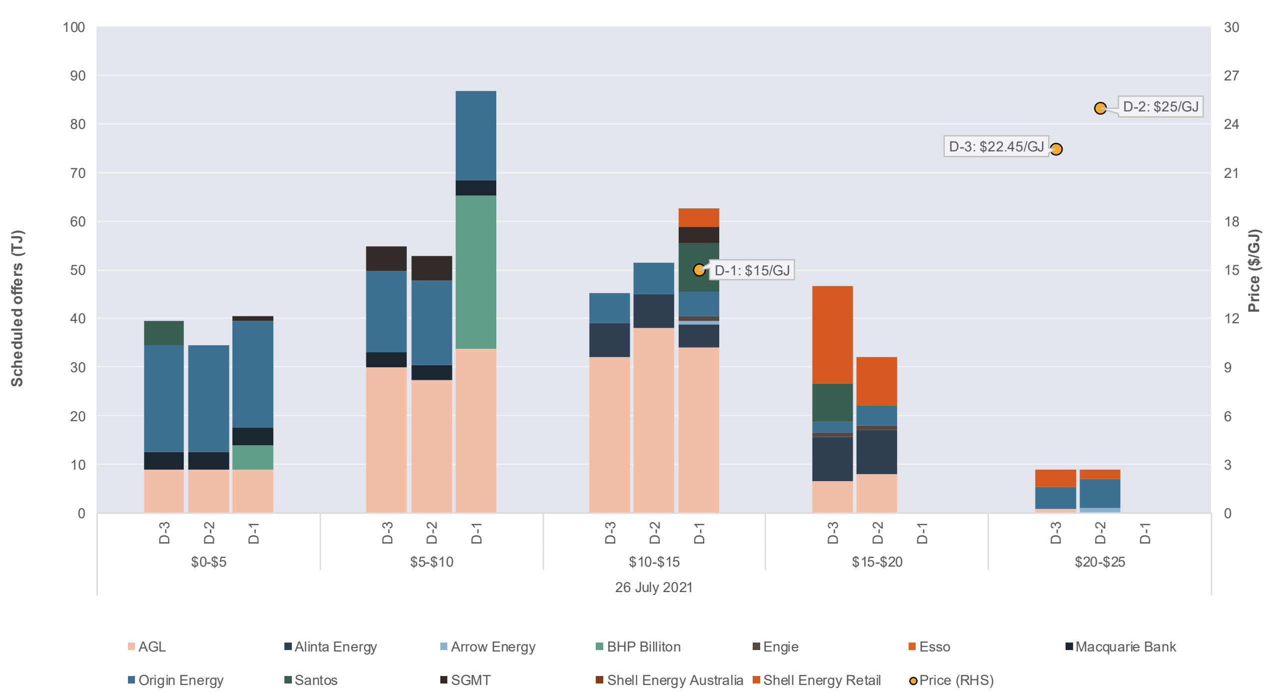
Figure 37 Participant offer stacks below $50 price bands in Sydney – 26 July 2021



Source: AER analysis using STTM data.

Note: Participant offers less than $50/GJ were grouped into price bands for the provisional and ex ante market schedules to show how different participants offered gas into the three market schedules.

Figure 38 Scheduled offers for GPG Gentailers, Exporter/Producers and Traders in Sydney – 26 July 2021



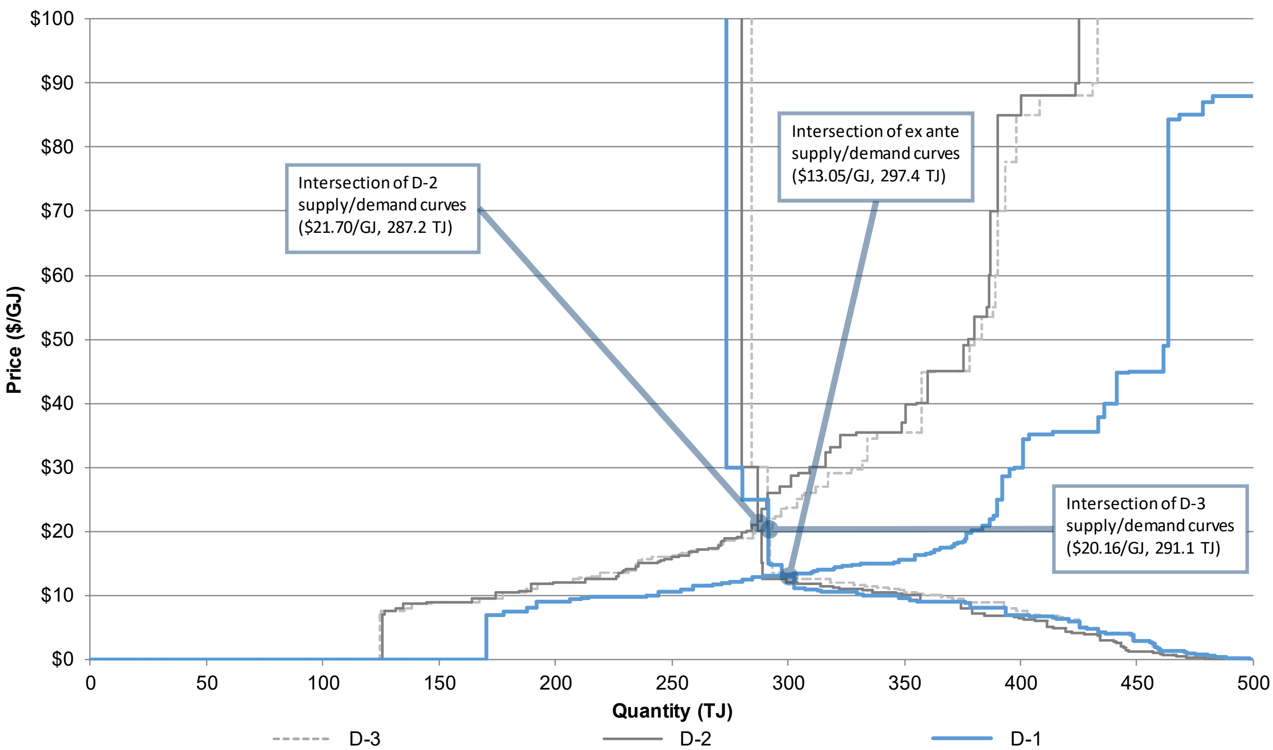
Source: AER analysis using STTM data.

Notes: The participant price bands are the actual price bands that were filled calculated for each of the market schedules.

5.1.8 Sydney STTM – 27 July

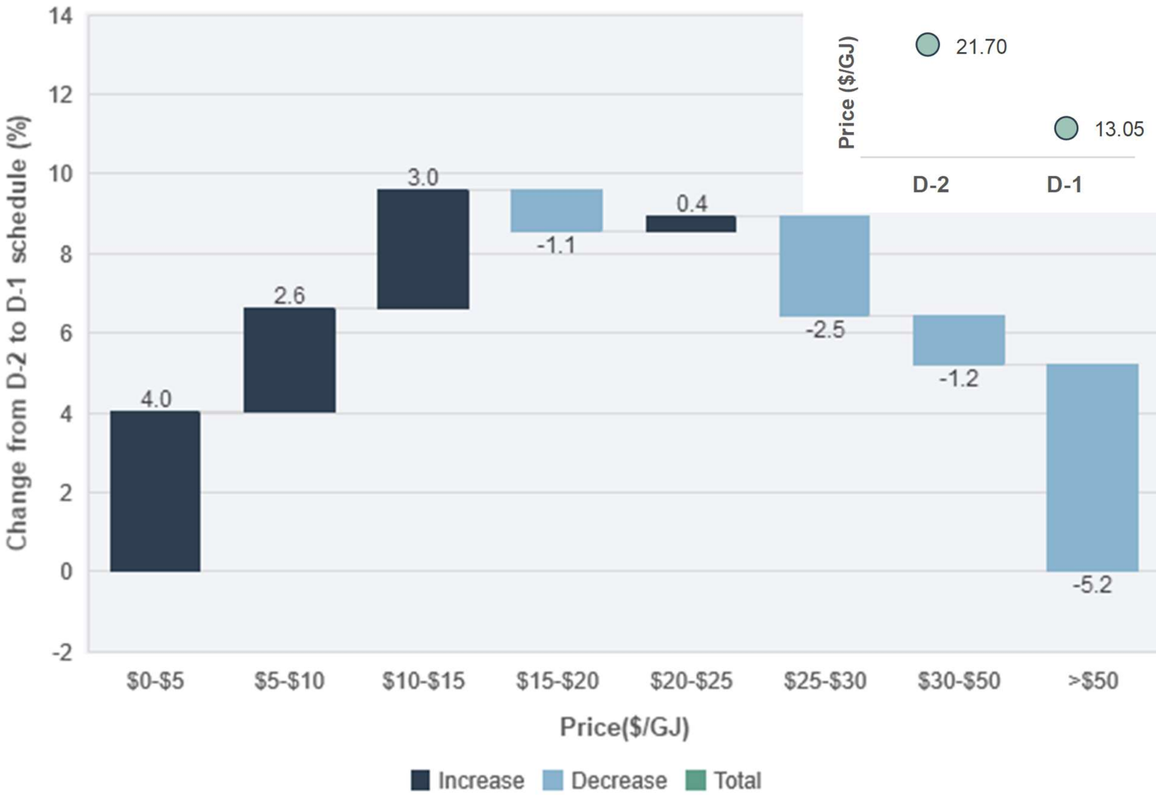
The market dynamics on 27 July were similar to those on 26 July although price outcomes were more moderate. The variation between the D-2 price ($21.70/GJ) and D-1 price ($13.05/GJ) in Sydney was $8.65/GJ (Figure 39). The gas price increased in the D-2 schedule from $20.16/GJ in the D-3 schedule due to a reduction in the quantity of gas offered by exporter/producers and GPG gentailers. Offers increased by 78.2TJ in the D-1 schedule and there was a reduction in the quantity of gas offered above $50/GJ of 5.1TJ.

Figure 39 Sydney – 27 July, D-2 provisional and ex ante bidding



Source: AER analysis using STTM data.

Figure 40 Change in gas offered between D-2 and D-1schedule in Sydney – 27 July 2021

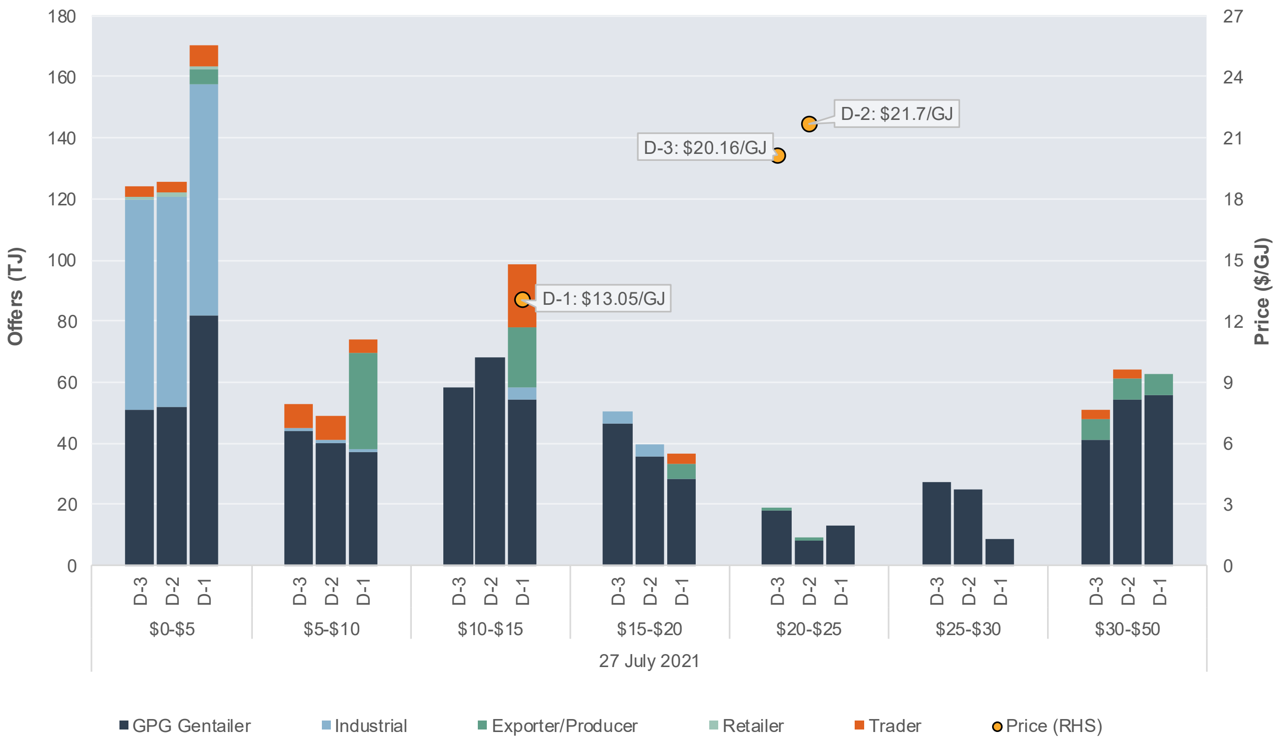


Source: AER analysis using STTM data.

Note: The percentage change between the D-2 and D-1 schedule is an indication of how the composition of offers shifted between the D-2 and D-1 schedule in absolute terms. If the percentage is positive within a price band it implies that in the D-1 schedule more gas was offered compared to the total offering of gas in all the price bands compared to the D-2 schedule, while a negative percentage indicates the opposite.

Exporter/producers were the largest suppliers of additional gas into the D-1 schedule with Bass Strait gas (BHP) being the most significant contributor (Figure 41 and Figure 42). Both traders and producers sourced transport capacity in the DAA to supply gas into the ex ante schedule. As with previous days of significant price variation, gas supply from a number of GPG gentailers (Shell, EnergyAustralia, Alinta Energy and AGL Energy) was reduced in the ex ante schedule relative to the D-3 and D-2 schedules due to being displaced by gas supply from exporter/producers and traders. In particular, AGL appeared to move gas into the lowest price band in order to maximise the chance of being scheduled.

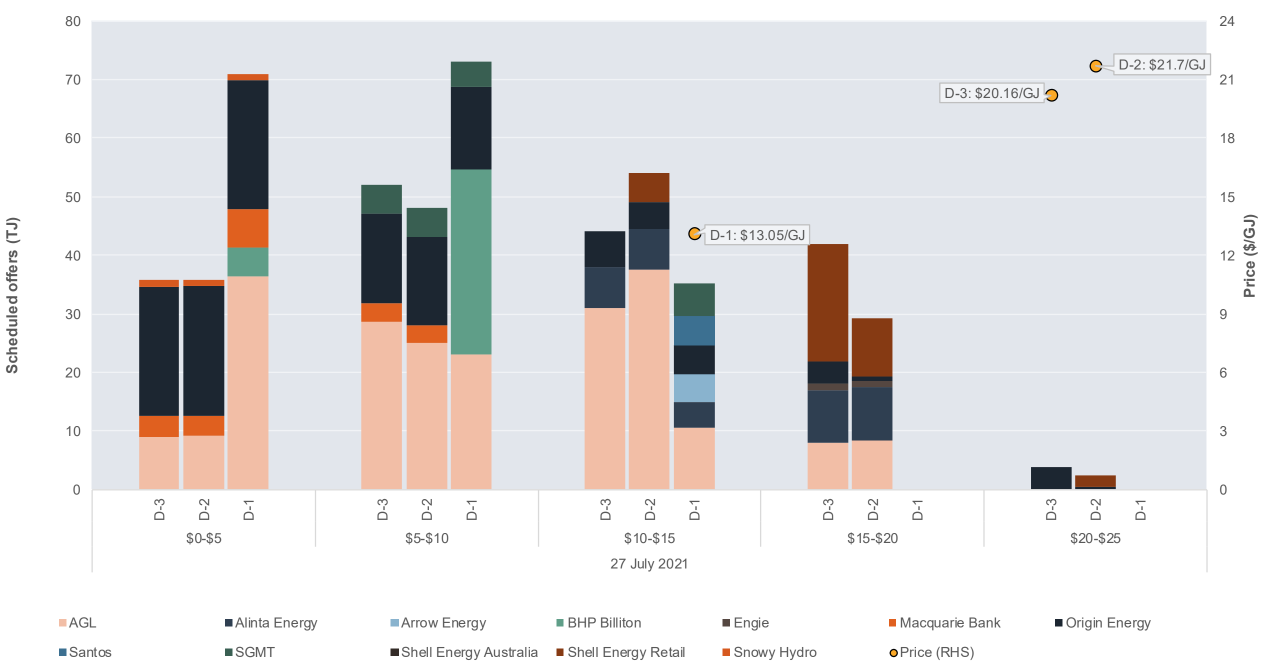
Figure 41 Participant offer stacks below $50 price bands in Sydney – 27 July 2021



Source: AER analysis using STTM data.

Note: Participant offers less than $50/GJ were grouped into price bands for the provisional and ex ante market schedules to show how different participants offered gas into the three market schedules.

Figure 42 Scheduled offers for GPG Gentailers, Exporter/Producers and Traders in Sydney – 27 July 2021



Source: AER analysis using STTM data.

Notes: The participant price bands are the actual price bands that were filled calculated for each of the market schedules.

5.2 Adelaide STTM (July)

Elevated GPG requirements and market prices across the southern states contributed to increasing the cost of gas supply in Adelaide on 8 and 9 July.[31] [32] With the majority of electricity generation in South Australia sourced from either gas or wind powered generation, low winds levels affecting southern states had a more significant impact on local generation requirements in the region.[33]

On SEAGas, rising Victorian DWGM prices influenced the higher cost of upstream supply, driving SEAGas offers to the Adelaide STTM above comparable supply on the Moomba to Adelaide Pipeline (MAP).

On the MAP, which provides the bulk of supply to the Adelaide hub, upstream demand predominantly comes from GPG. Increased GPG demand on the pipeline over consecutive days from 5 July put upwards pressure on gas costs in the Adelaide STTM. The higher offer costs were reflected in the ex ante market price from 6 July and flowed through to provisional pricing schedules for the following gas days.[34]

While increased flows south through QSN link were supplementing Moomba supply on the MAP in July, these were down on previous years.[35] This had a higher impact on Moomba to Sydney Pipeline (MSP) flows, however appeared to drive up offer prices to both the Adelaide and Sydney STTMs. This coincided with elevated export levels and issues impacting Victorian production output.

Figure 43 illustrates the MAP and SEAGas pipelines, their respective custody transfer points, and the Adelaide distribution network. The figure also shows upstream gas powered generation.

31 Gas generation levels across the east coast increased from 5 July. This affected upstream gas usage on both the Moomba to Adelaide Pipeline and SEAGas pipeline which supply the Adelaide STTM.

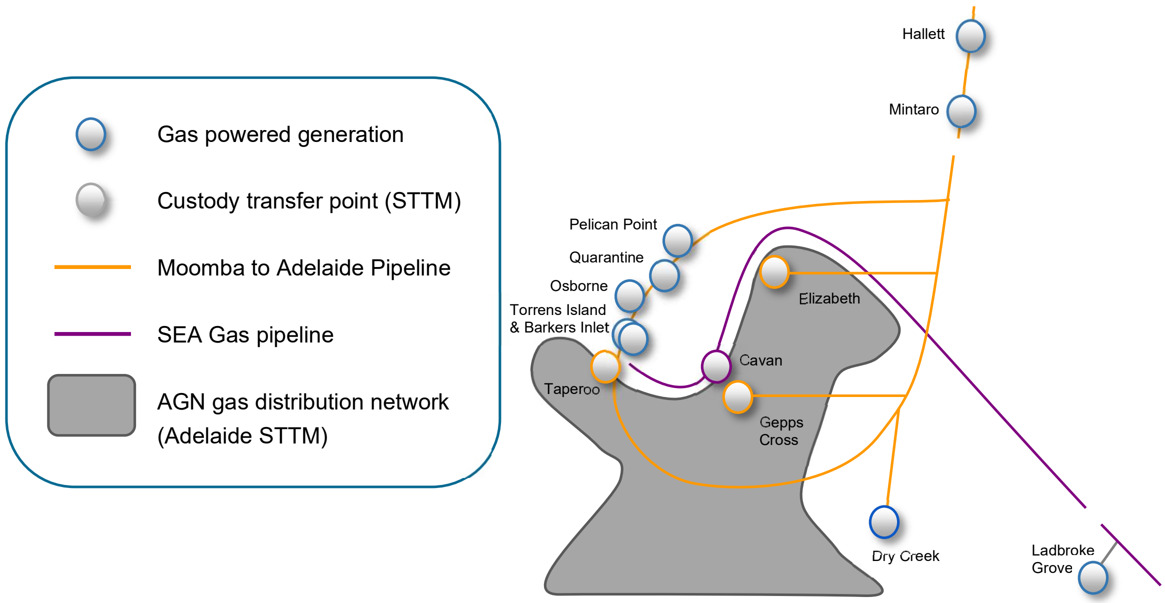
32 The variation between D-2 and D-1 schedule prices in Adelaide on 8 July was exactly $7/GJ, just short of exceeding the price reporting threshold. Preliminary analysis for the events of 8 and 9 July was presented in the AER gas weekly report (https://www.aer.gov.au/wholesale-markets/performance-reporting/gas-report-4-10-july-2021).

33 Wind levels in South Australia had also dropped from 9 July to provide less than 20% of local electricity generation output.

34 In addition to participants' increased supply costs impacting market offers, depleted linepack accounts on preceding days may limit an individual participant's ability to supply gas quantities submitted in provisional schedule forecasts (linepack account refers to the amount of gas on the pipeline allocated to an individual participant for usage over a pre-defined period).

35 The Queensland to South Australia/New South Wales (QSN) link is the section of the South West Queensland Pipeline (SWQP) connecting Queensland gas transmission pipelines to the southern states. The link is located between Ballera (in Queensland) and Moomba (in South Australia), and can deliver gas to the Moomba to Adelaide Pipeline (MAP) and Moomba to Sydney Pipeline (MSP). The connection at Moomba also provides the ability to deliver bi-directional gas flows between Queensland and South Australia.

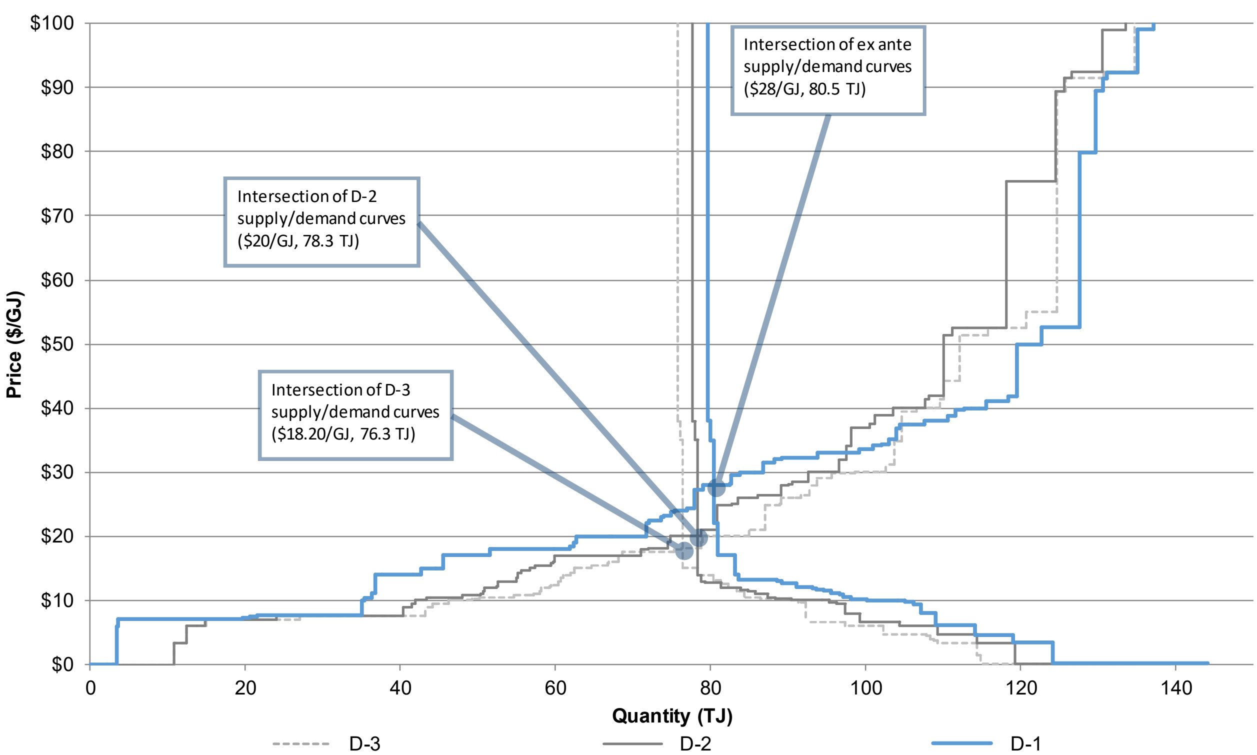
Figure 43 The Adelaide STTM hub and upstream gas powered generation



5.2.1 Adelaide STTM – 9 July

On 9 July, the variation between the D-2 price ($20/GJ) and D-1 price ($28/GJ) in Adelaide was $8/GJ (Figure 44).

Figure 44 Adelaide – 9 July, D-2 provisional and ex ante bidding



Source: AER analysis using STTM data.

On 9 July, ex ante schedule changes led to small increases in controllable hub demand and backhaul on both SEAGas and the MAP, and price taker demand (collectively amounting to less than 2.2 TJ), with the increase from the forecast price primarily driven by rebidding of gas supply.

There was a drop in gas priced below $10/GJ, and only a small amount of gas was available between $20/GJ and $30/GJ on SEAGas (Figure 45). GPG gentailers provided the majority of supply being offered into the Adelaide market.

The increasing cost of supply on the MAP and a steeper supply curve left the market susceptible to larger price swings as a result of minor changes to supply. This was compounded with a net reduction of lower priced offers on SEAGas.

Just under half of the decrease in SEAGas offers below $10/GJ was linked to the removal of floor priced capacity by Origin Energy, whose upstream Ladbroke Grove power station was dispatched above initial forecast levels across the morning and evening peak period (Figure 47). EnergyAustralia, whose upstream generation on the MAP (Hallett power station) was forecast to dispatch during the morning peak but did not generate until the evening, had more MAP offers scheduled ex ante following rebidding that shifted lower priced capacity offered on SEAGas over to MAP.[36] As a result, supply from SEAGas for these 2 participants reduced to zero in the ex ante schedule, with a 15.3 TJ increase in their schedule supply from MAP offsetting SEAGas reductions. Rebidding from AGL Energy shifted available capacity on both MAP and SEAGas to higher prices, with a resulting reduction in MAP scheduled supply.[37]

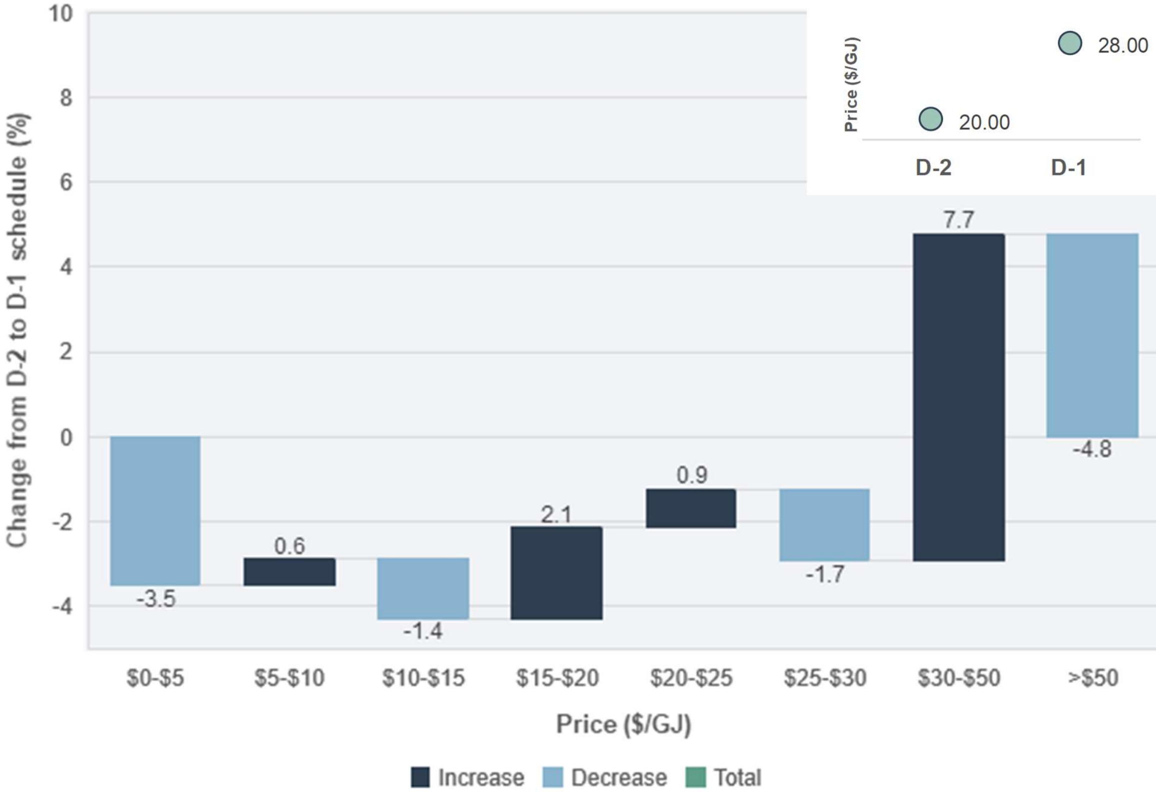
Separate to the redistribution of supply costs between MAP and SEAGas by GPG gentailers, changes to industrial supply offers on the MAP also impacted market prices due to the steep supply curve, with a redistribution of supply by Adelaide Brighton Cement (6 TJ) and Alinta Energy (1.5 TJ) somewhat offset by additional supply being offered by Simply Energy and Infrabuild.[38]

[36] D-2 offers by EnergyAustralia provided 5 TJ of supply below $15/GJ on SEAGas, with most of their remaining SEAGas and MAP offers priced above $30/GJ. Rebidding shifted 5 TJ of capacity below $15/GJ over to the MAP, while SEAGas offer prices increased above $30/GJ ex ante.

[37] AGL, whose generation assets are located off the SEAGas pipeline close to the Adelaide hub at Torrens Island (Torrens Island and Barkers Inlet power stations), also has the ability to source gas from connection points on the Moomba to Adelaide Pipeline. Higher supply from MAP over the week may have contributed to scheduled supply into Adelaide remaining relatively stable across the forecast schedules for 9 July.

[38] Infrabuild offered 2TJ of additional capacity in the $10-15/GJ price range.

Figure 45 Change in gas offered between D-2 and D-1schedule in Adelaide – 9 July 2021



Source: AER analysis using STTM data.

Note: The percentage change between the D-2 and D-1 schedule is an indication of how the composition of offers shifted between the D-2 and D-1 schedule in absolute terms. If the percentage is positive within a price band it implies that in the D-1 schedule more gas was offered compared to the total offering of gas in all the price bands compared to the D-2 schedule, while a negative percentage indicates the opposite.

Figure 46 Participant offer stacks below $50 price bands in Adelaide – 9 July 2021

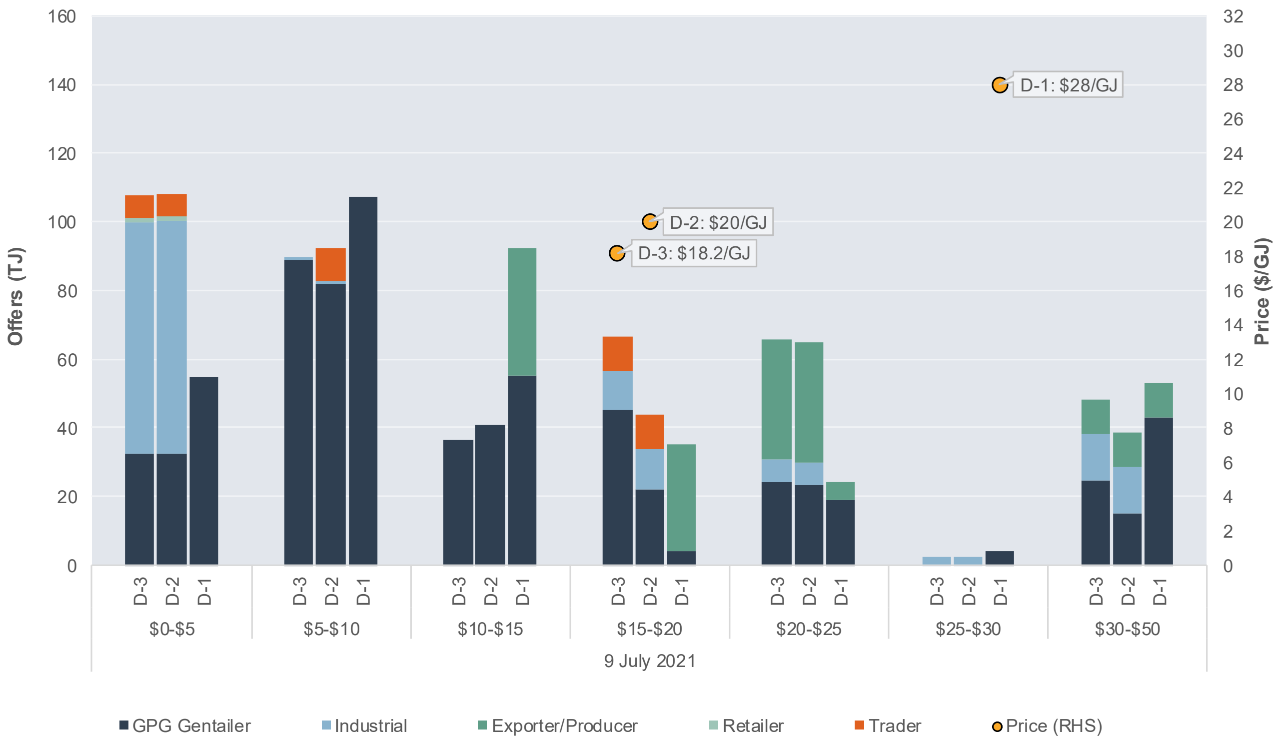
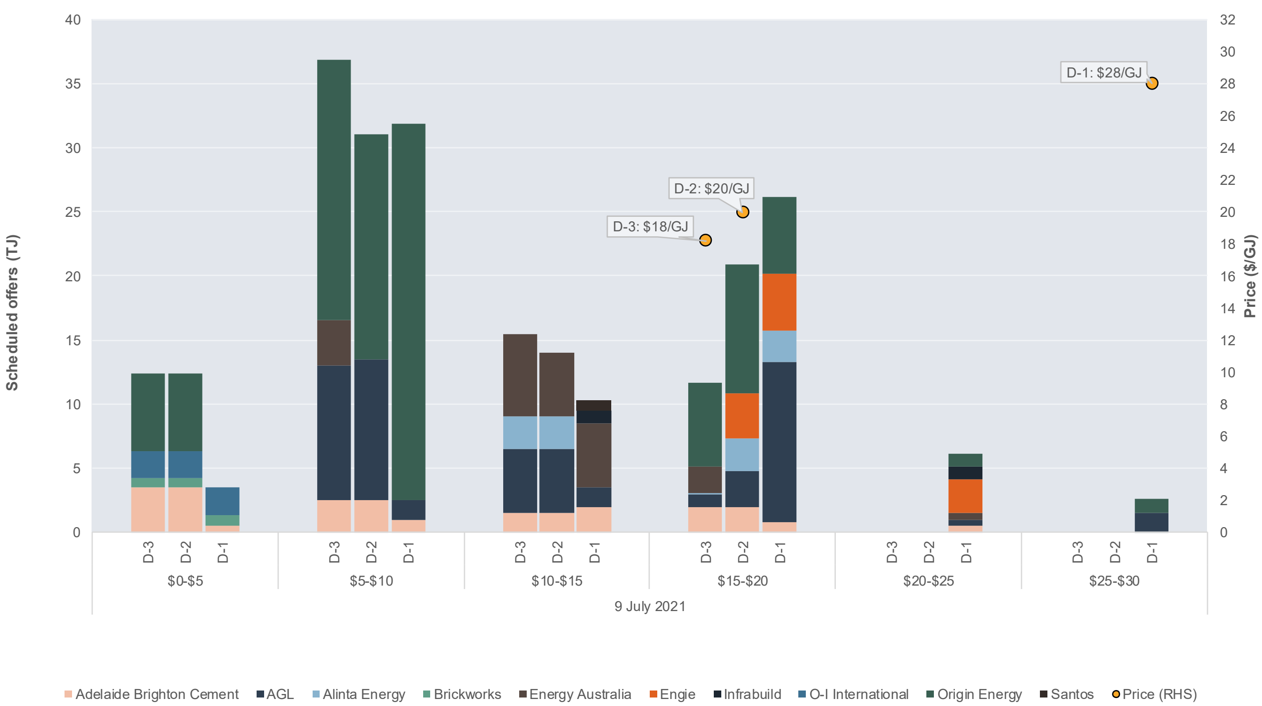


Figure 47 Scheduled offers in Adelaide – 9 July 2021



Source: AER analysis using STTM data.

Notes: The participant price bands are the actual price bands that were filled calculated for each of the market schedules.

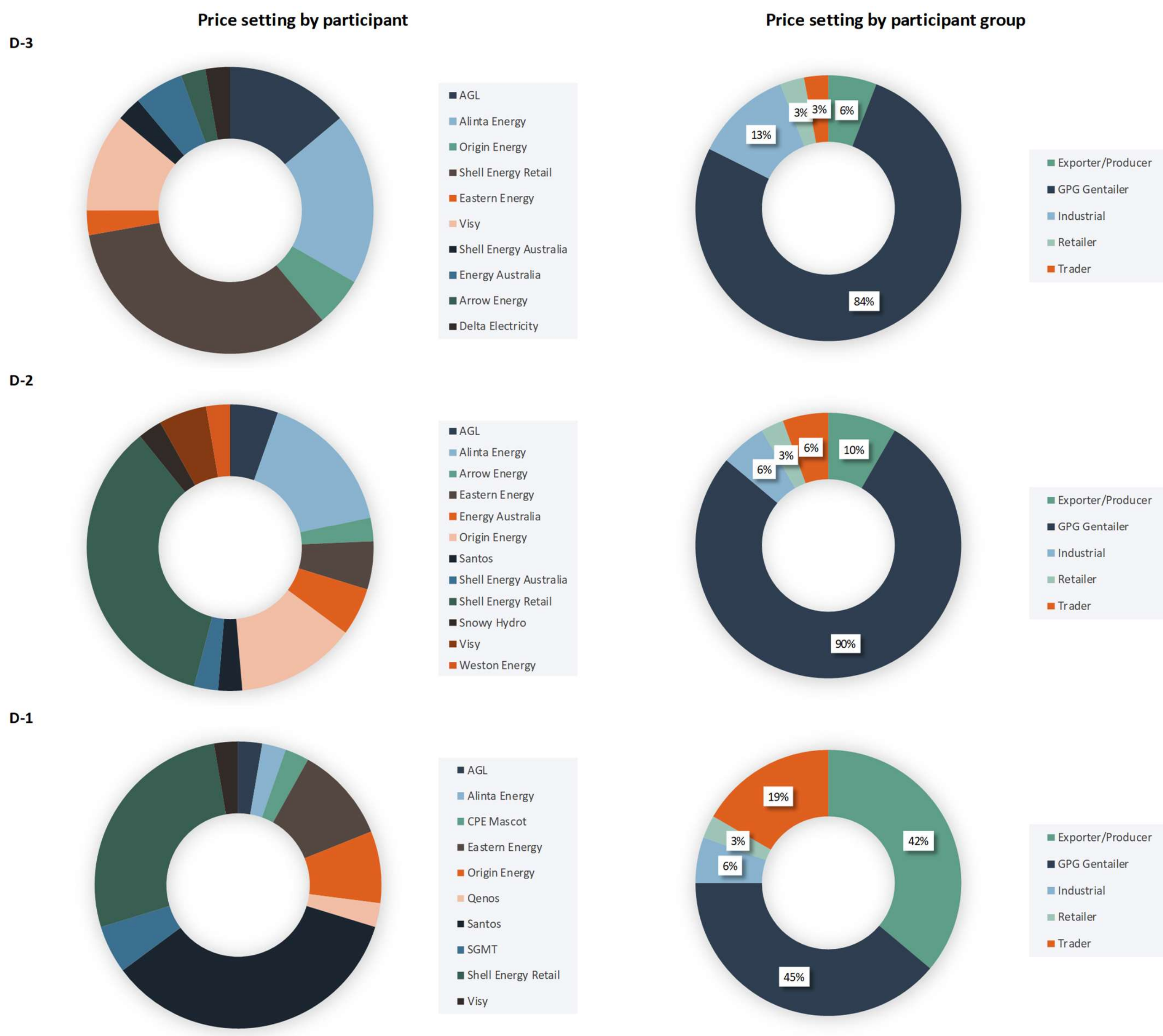
6 Appendices

6.1 Appendix A – Price setter trends across July

Sydney

Price setting shifted in July to exporter/producers and traders setting the price more often in the D-1 schedule compared to the D-3 or D-2 schedules (Figure 48). This underscores the general observation that exporter/producers and traders were incentivised to enter the market by high prices. Santos, EEBG and SGMT particularly featured in price setting prices at the D-1 schedule.

Figure 48 Price setting for July in the Sydney STTM



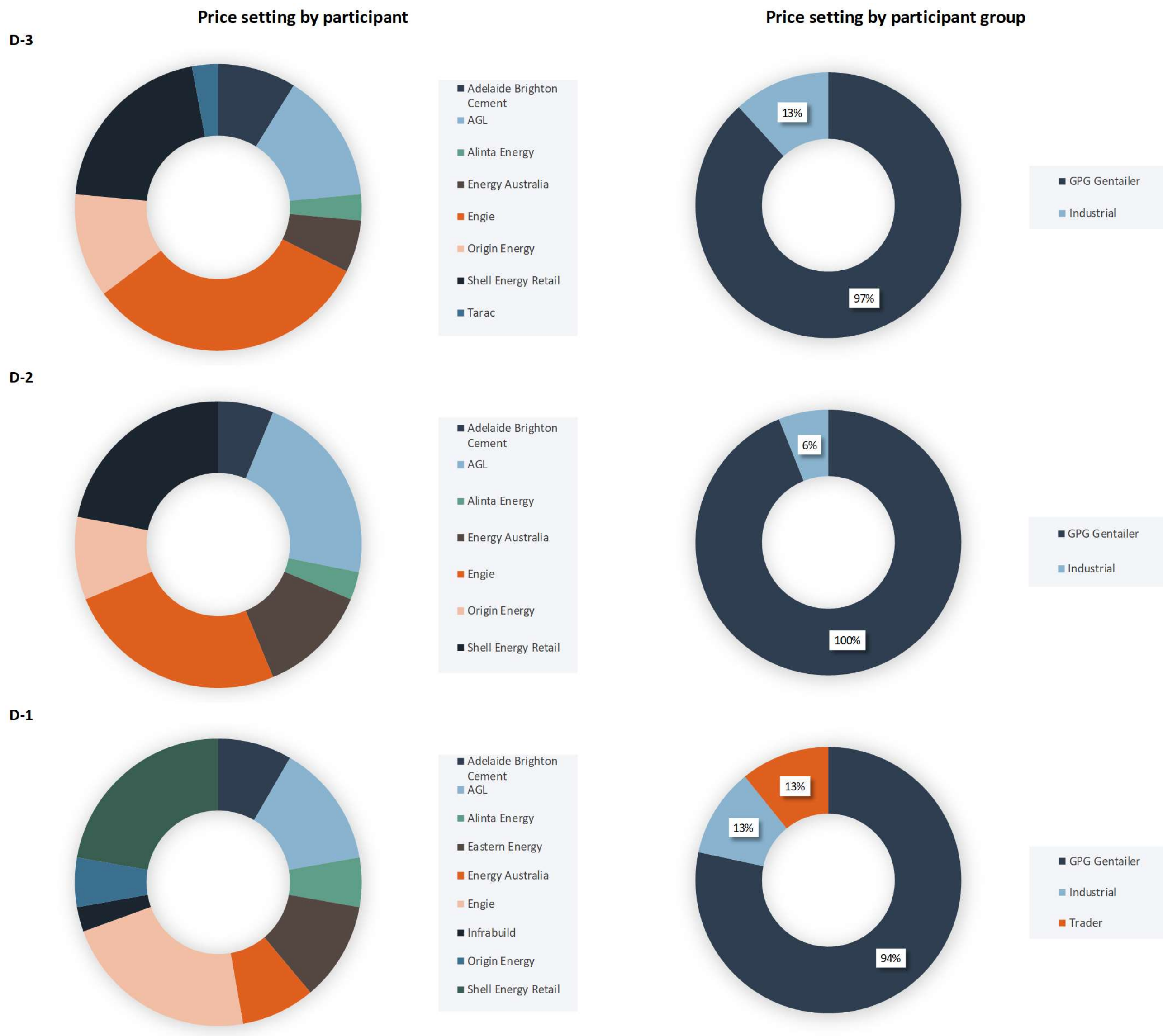
Source: AER analysis using STTM data.

Notes: The price can be set by more than one participant on a given gas day resulting in the total percentage being greater than 100%. Participant groupings were only counted once for each gas day.

Adelaide

In the Adelaide STTM, EEBG stands out as a participant that was actively entering the market at the D-1 schedule and setting the market price (Figure 49).

Figure 49 Price setting for July in the Adelaide STTM

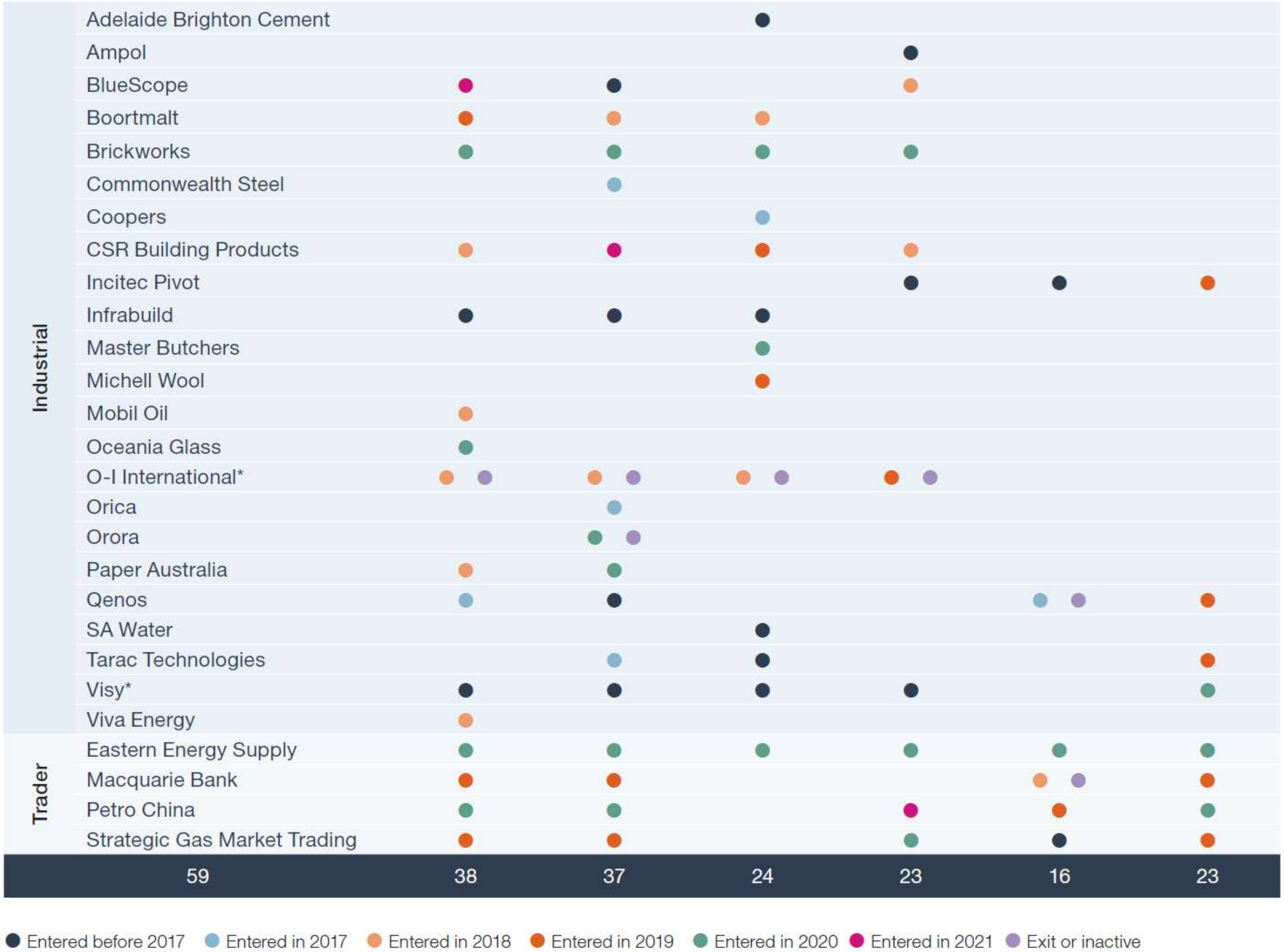


Source: AER analysis using STTM data.

Notes: The price can be set by more than one participant on a given gas day resulting in the total percentage being greater than 100%. Participant groupings were only counted once for each gas day.

6.2 Appendix B – Gas participant list

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



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.

* Click Energy was aquired by AGL, ERM was aquired by Shell (Shell Retail), O-I International was aquired by Visy.
* Arrow also operates the Braemar 2 power station.
* ICAP Brokers is also active in the GSH, but does not trade gas commodities (trade facilitior).