Gas Market Report

AUSTRALIAN ENERGY REGULATOR

4 – 10 July 2021

Weekly Summary

Average prices increased significantly from the previous week, with daily prices reaching their highest levels this winter in all markets.[1] In Adelaide, demand reduced slightly from the previous week, while average demand in Brisbane remained unchanged. Average demand in Sydney and Victoria increased by 6% and 7% respectively.

Daily prices increased to very high levels towards the end of the week, particularly in southern regions, sitting around $24-35/GJ on individual days in Sydney, Adelaide and Victoria from 7 July (figure 3).

Gas generation demand over the week increased to its 2nd highest level this year, averaging around 598 TJ/d across the mainland (see figure 5.1).

On 7 July, the variation between the D-2 provisional price ($19/GJ) and D-1 ex ante price ($27.56/GJ) in Sydney was $8.56/GJ. On 9 July, the variation between the D-2 provisional price ($20/GJ) and D-1 ex ante price ($28/GJ) in Adelaide was $8/GJ. The price variations of greater than $7/GJ exceeded a reporting threshold outlined in the STTM Significant Price Variation Guideline. The AER will investigate and publish a significant price variation report on these events.

On 8 July, the variation between the D-2 provisional price ($18.20/GJ) and D-1 ex ante price ($25.20/GJ) in Adelaide was $7/GJ. On 9 July, the trade weighted market price in Victoria was $34.95/GJ. Both events, which came close to exceeding significant price variation thresholds outlined in AER reporting guidelines[2], are analysed in this report.

Long term statistics and explanatory material

The AER has published an explanatory note to assist with interpreting the data presented in its weekly gas market reports. The AER also publish a range of longer term statistics on the performance of the gas sector including gas prices, production, pipeline flows and consumer demand.

Market overview

Figure 1 sets out the average daily prices ($/GJ) for the current week, and demand levels, compared to historical averages. Regions shown include the Victorian Declared Wholesale Market **(VGM or Victorian gas market)** and for the Sydney **(SYD)**, Adelaide **(ADL)** and Brisbane **(BRI)** Short Term Trading Market hubs **(STTM)**.

[1] The highest daily price occurred in Victoria on 9 July, with the weighted imbalance price reaching $34.95/GJ. In Adelaide, Brisbane and Sydney the maximum daily prices were $28.01/GJ (10 July), $20.08/GJ (8 July) and $27.56/GJ (7 July) respectively.

[2] Significant price variation guidelines and the relevant reporting threshold triggers are published on the AER website for the STTM (STTM Significant Price Variation Guideline) and Victoria (DWGM Significant Price Variation Guideline).

Figure 1: Average daily prices and demand – all markets ($/GJ, TJ)[3]

	Victoria		Sydney		Adelaide		Brisbane	
	Price	Demand	Price	Demand	Price	Demand	Price	Demand
04 Jul - 10 Jul 2021	22.17	1048	21.67	316	21.39	78	17.25	94
% change from previous week	90	7	79	6	74	-3	56	0
21-22 financial YTD	19.45	1025	18.97	308	18.71	80	15.46	93
% change from previous financial YTD	351	8	417	-4	245	-3	369	-17

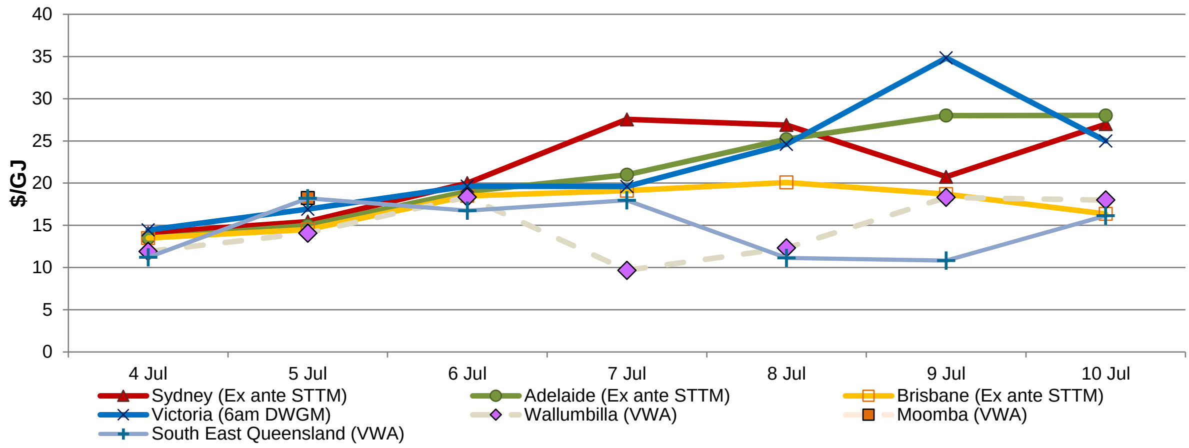
Figure 2 sets out price and demand information for the voluntary Wallumbilla and Moomba Gas Supply Hubs **(GSH)**.

Figure 2: Average prices and total quantity – Gas supply hub ($/GJ, TJ)[4]

	Moomba		South East Queensland		Wallumbilla	
	Price	Quantity	Price	Quantity	Price	Quantity
04 Jul - 10 Jul 2021	18.25	5	12.35	415	14.60	743
% change from previous week	-	-	14	519	34	258
21-22 financial YTD	18.25	5	12.26	451	14.19	843
% change from previous financial YTD	413	-96	274	14	329	-45

Figure 3 illustrates the daily prices in each gas market, as defined in figures 1 and 2.

Figure 3: Daily gas market prices ($/GJ)



3 Average daily quantities are displayed for each region. The weighted average daily imbalance price applies for Victoria.

4 The prices shown for the GSH in Moomba, South East Queensland and Wallumbilla are volume weighted average (VWA) prices for all products traded across the period. The total quantity contributing to the weighted price is displayed for these GSH. Reported values for Moomba are the aggregate of trades on the Moomba to Adelaide Pipeline (MAP) and the Moomba to Sydney Pipeline (MSP). Historic trades for RBP and SWQP are grouped under WAL, (including in-pipe trades on the RBP).

Figure 4 compares average ancillary market payments (VGM) and balancing gas service payments (STTM) against historical averages.

Figure 4: Average daily ancillary payments ($000)

	Victoria Ancillary Payments*	Sydney MOS	Adelaide MOS	Brisbane MOS
04 Jul - 10 Jul 2021	-	22.66	2.43	0.45
% change from previous week	-	-20	-46	-67
21-22 financial YTD		25.92	3.52	0.90
% change from previous financial YTD		29	-91	-21

* Ancillary payments reflect the compensation costs for any additional injections offered at a price higher than the market price. Note: only positive ancillary payments, reflecting system constraints will be shown here.

More detailed analysis on the VGM is provided in section 1.

Figure 5 shows the quantity and volume weighted prices of products traded in the Gas Supply Hub locations at Moomba, South East Queensland and Wallumbilla.

Figure 5: Gas supply hub products total traded for the current week ($/GJ, TJ)[5]

	Moomba		South East Queensland		Wallumbilla*	
	VWA price	Quantity	VWA price	Quantity	VWA price	Quantity
Balance of day	18.25	5.0	16.88	68.0	16.66	178.0
Daily	-	-	10.31	273.0	15.22	229.0
Day ahead	-	-	14.64	46.0	17.46	152.2
Weekly	-	-	17.50	28.0	10.27	91.0
Monthly	-	-	-	-	8.70	93.0
Total	**18.25**	**5.0**	**12.35**	**415.0**	**14.60**	**743.2**

* includes non-netted (off-market) trades.

Figure 6 shows Bulletin Board pipeline flows for the three LNG export pipeline facilities and the production output at related production facilities in the Roma region.

5 Further information about new product trading locations in Victoria (Culcairn) and Sydney (Wilton) is available in section 6. Gas Supply Hub).

Figure 6: Average daily LNG export pipeline and production flows (TJ)*

	APLNG	GLNG	QCLNG	Total
Production	1505	927	1772	4204
Export Pipeline Flows	1603	915	1415	3933
% change from previous week (pipeline flows)	-1	-14	-3	-5
21-22 financial YTD flows	1423	995	1306	3724

* Production quantities represent flows from facilities operated by APLNG, Santos and QGC. Gas from individual facilities may also supply the domestic market, other LNG projects or storage facilities.

Detailed market analysis

High prices across east coast gas markets

Spot prices started to rise on 6 July, increasing to $18.50-20/GJ across the markets. Ex ante prices in Brisbane were relatively subdued, setting the floor to the price increases and reaching a maximum of just over $20/GJ on 8 July, while southern markets were more volatile. In Victoria, this aligned with a notable reduction in capacity offered between $9-18/GJ, particularly in the beginning-of-day schedule at Iona, VicHub and Culcairn, while demand gradually increased.[6] In Brisbane, there was a similar shift in offer prices, with quantities offered between $6-14/GJ narrowing significantly across ex ante schedules from 6 July. Demand in Sydney on 6 July increased to its highest level for the week alongside increased offer prices.[7] In Adelaide, cheaper offers from the SEAGas pipeline decreased.[8]

Daily gas market prices in southern regions saw significant increases from 7 July. This commenced in Sydney, with prices in Victoria and Adelaide climbing above $24/GJ from the following day. Gas supply to southern markets was supplemented by increased flows from Queensland on the QSN link as southern supply in Victoria was limited by a partial outage at Longford and diminishing storage levels at Iona.[9] Supply increased to the MAP and MSP, but were significantly higher on MSP towards Sydney, with limited amounts flowing through to Culcairn and into the Victorian market (particularly on higher priced days 7-10 July in Victoria).[10]

Gas powered generation (GPG) was relatively high across the east coast over the week, driven up by low levels of wind generation affecting southern regions. This had a noticeable impact, leading to higher gas generation in New South Wales (where gas generation is

6 The 6 am demand forecast in Victoria rose to 1050 TJ on 4 July, with the following 3 days above that level (up to 1100 TJ on 9 July).

7 Higher demand resulted from participants shifting controllable withdrawal bids to higher prices in Sydney on 6 July. Floor price offers on the EGP reduced slightly in the ex ante schedule (down 5 TJ).

8 Increased ex ante quantities offered around $7-8/GJ on MAP, however quantities priced above and below this level generally narrowed, largely on SEAGas.

9 Flows south on QSN link increased to almost 550 TJ on 6 July and reached almost 640 TJ/day on 8 and 9 July. This occurred during a scheduled maintenance period for one of the 3 Queensland export projects. Planned maintenance was scheduled to occur from 15 June to 13 July (greater than one half of a train, but not greater than one LNG train).

10 Culcairn constraints into the DWGM reflected upstream demand on the Moomba to Sydney Pipeline from domestic users, including flow restrictions linked to instantaneous delivery rates to the Uranquinty power station and the Wilton(Sydney)/Canberra delivery points.

usually quite low) and in South Australia, while moderate[11] GPG demand in Victoria coincided with colder weather and higher residential gas market demand.

Victoria

In Victoria, cold temperatures drove higher residential demand, with Melbourne's maximum temperature averaging just 13.1 degrees across the week.[12] Weekday gas powered generation demand inside the declared transmission system (DTS) was upwards of 45 TJ, reaching over 71 TJ on 9 July.[13]

Onshore maintenance at the Longford production facility reduced the daily production capacity outlook to 800-900 TJ from 29 June.[14] With Victorian market demand increasing above 1000 TJ/day from 3 July, continuing across the week, the proportion of market demand being supplied by Longford decreased to around 60%, resulting in an increased reliance on alternative supply sources (see figure 1.5).[15] The majority of this supply was sourced from the Iona underground storage facility, where storage levels reduced below 14 PJ from 1 July.[16] This coincided with a noticeable reduction in Iona's supply capacity available at prices between $10-30/GJ over July, alongside a significant drop in offers below that level from 9 July.

Figure 7 shows the beginning-of-day gas supply quantities offered at the Iona underground storage facility across 2021. The figure illustrates an increase in quantities offered at lower prices heading into winter, coinciding with high levels of utilisation over June, followed by net withdrawals being constrained to zero across July (from late-June).[17] This led to a decrease in mid-range offer prices (between $9-18/GJ) that influenced a steeper supply curve.

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11 Gas generation demand in Victoria was largely driven by higher generation levels at Newport (driving moderate demand inside the gas market) and Mortlake (in western Victoria, driving higher demand outside the gas market).

12 Weekday maximum temperatures in Melbourne ranged from 12 to 13.1 degrees, with minimums falling as low as 2 degrees on 9 July.

13 State-wide GPG weekday demand ranged between 124 TJ and 168 TJ in Victoria. While not reaching particularly high levels for the state, the additional demand contributed to driving demand above 1 PJ/day across the week.

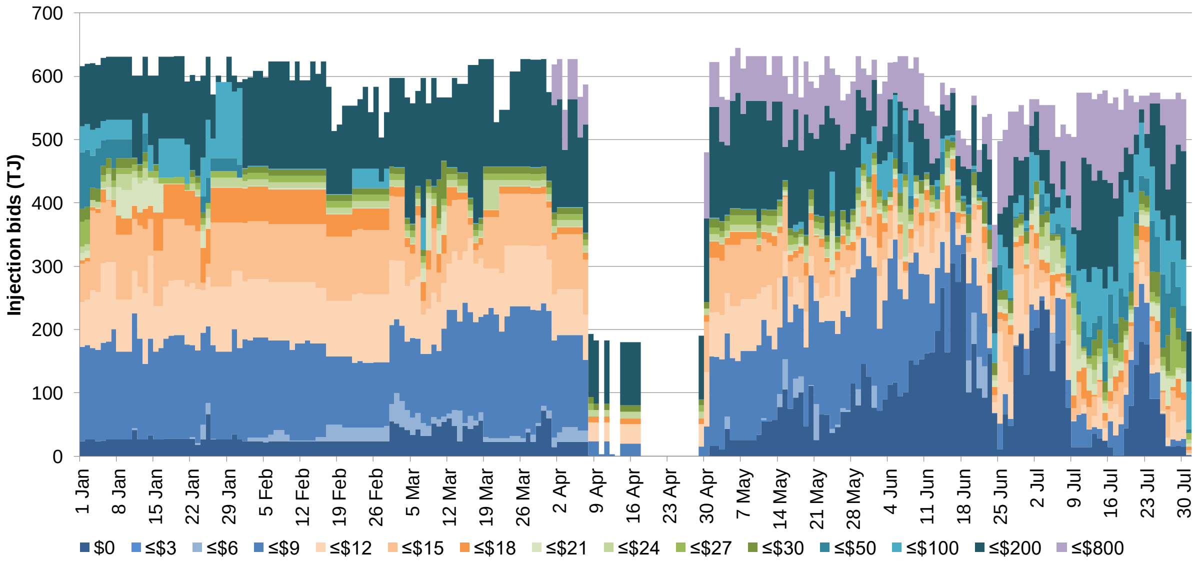
14 The constrained quantity amounted to roughly 100 TJ/day partial outage. The short term outlook for the facility increased to 850 TJ/day from 3 July, increasing to 900 TJ/day by 10 July.

15 The majority of supply to the Victorian market not provided by Longford came from the Iona underground storage facility, supplemented by injections at Culcairn – from the Moomba to Sydney Pipeline (MSP), VicHub – from the Eastern Gas Pipeline (EGP) and TasHub – from the Tasmanian Gas Pipeline (TGP). *Note: VicHub and TasHub supply is largely sourced from Longford production.*

16 Nameplate storage capacity at Iona is 23.5 PJ. Storage levels reached a high of 24.6 PJ on 10 May (the highest level recorded over the past 5 years), however increased supply capability and high utilisation of supply from the facility over June saw Iona injections reach a record level of over 250 TJ/day on average across the month.

17 The constraints related to repair works following the isolation of a leaking pipeline segment on 24 June (participants were notified of a short-notice maintenance outage on 22 June around repair work on the corroded pipeline segment).

Figure 7: Iona injection bid capacity in the Victorian DWGM (6 am schedules)



Tight supply/demand conditions affected the Victorian market on the 8 and 9 July gas days. Scheduled demand on 8 July was just below 1.1 PJ and remained around that level for the following gas day. While prices were high, around $25/GJ for the 8 July gas day, they remained below potentially significant increases that could have occurred were demand to increase.[18]

On 9 July, the Victorian imbalance price reached $34.95/GJ and came close to exceeding a significant price variation (SPV) reporting threshold.[19] The beginning-of-day (6 am) schedule price reached $34.84/GJ, climbing to $58.44/GJ for the 10 am schedule as demand forecasts were revised upwards.[20] This was the result of multiple factors, with low wind generation one of the main drivers influencing higher gas generation in the electricity market and limiting gas deliveries from Culcairn. With production issues limiting Longford supply, constraints at Culcairn, and steep increases in offer prices at Iona, gas was redirected on the Eastern Gas Pipeline to be delivered into Victoria through the VicHub supply point.

Figure 8 shows high price sensitivities across days where a 10% increase in demand would have resulted in significantly higher schedule prices.

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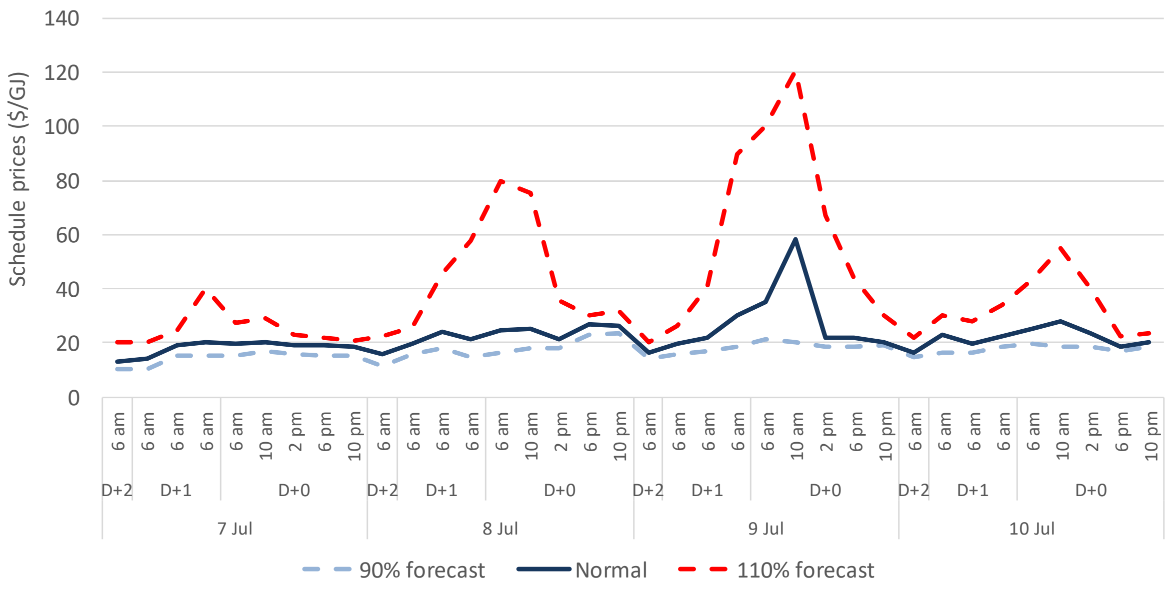
18 Price sensitivities yielded prices of $80/GJ and $75.44/GJ for the 6 am and 10 am schedules at 110% demand levels.

19 A SPV occurs when the Trade Weighted Market Price published by AEMO on a gas day is more than three times the average price for the previous 30 days and the Trade Weighted Market Price is equal to or greater than $15/GJ, as defined in the DWGM Significant Price Variation Guideline. On 9 July, the 30 day rolling average imbalance price was $11.83/GJ (3 times the rolling average was just under $35.50/GJ).

20 Forecast BOD prices over the preceding days escalated from $16.35/GJ on D+2, to $19.70/GJ, $22/GJ and $30/GJ over consecutive D+1 forecast schedules. Price sensitivities showed significant increases to price levels from the latter D+1 forecast, with a 10% increase in demand levels pushing prices up to $89.91/GJ, increasing to as much as $120.45/GJ for the 10 am schedule (D+0). The 10 am increase in scheduled demand coincided with a sharp increase in the heating load (driven by cold weather).

Figure 8: DWGM forecast price sensitivities across daily scheduling intervals*



* Prices are forecast for the 6 am scheduling interval two days ahead (D+2) for the bid cut-off time at 11 am, and day-ahead (D+1) for bid cut-off times at 7 am, 3 pm and 10 pm, prior to daily schedules at 6 am, 10 am, 2 pm, 6 pm and 10 pm which contribute to setting the daily imbalance price.

Sydney

From 6 July, with the exception of 9 July, Sydney experienced sizable increases in ex ante price levels in comparison to D-2 provisional forecasts.[21] The variation between D-2 and ex ante prices saw increases of $1.68-8.56/GJ over 4 days. The trend was driven by reduced ex ante offer quantities (compared to D-2) being bid into the Sydney market in prices between $0-8/GJ across June, with ex ante quantities priced in this range dropping close to zero from 7 July.[22] This resulted in a steep jump in offers above $0/GJ in ex ante supply curves across 7-10 July.

On 7 July, the D-2 price was $19/GJ but the ex ante price reached $27.56/GJ, a variance of $8.56/GJ, triggering one of the AER's significant price variation reporting thresholds.[23] Rebidding shifted a large amount of capacity to higher prices. Gas quantities available in lower price bands between $5-30/GJ were reduced by 79 TJ.[24] Rebidding shifted significant quantities of controllable demand to higher prices in the ex ante schedule, however the reduction of cheaper capacity limited the amount of additional demand scheduled.[25]

The AER will investigate and publish a significant price variation report on the event.

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21 On 9 July, the ex ante price in Sydney decreased to $20.75/GJ from a D-2 forecast of $25.55/GJ due to a significant downward shift in offer prices, despite additional demand resulting from controllable withdrawal rebidding.

22 Only 5.8 TJ and 1.4 TJ of gas offers were bid into Sydney's ex ante schedules at non-zero prices below $8/GJ for the 7 and 8 July gas days respectively.

23 When there is a variation of greater than $7/GJ between the D-2 price and ex ante (D-1) price in the STTM.

24 Capacity available between $5-10/GJ declined by 56TJ, and capacity priced between $20-25/GJ declined by 35.4 TJ. While some capacity was shifted to the price floor (5.3TJ) and the $10-20/GJ price range (33.6 TJ), there was a significant increase in gas offers being shifted to prices above $30/GJ. Reduced availability of lower priced capacity was largely attributable to rebidding by GPG Gentailers. Participants classified as GPG Gentailers in the Sydney market are AGL, Alinta, EnegyAustralia, Hydro Tasmania, Origin, Shell Retail, and Snowy Hydro.

25 Demand increased by 11.2 TJ in the ex ante schedule. A slight reduction in pricetaker (uncontrollable) demand (2.2 TJ) was offset by 15.5 TJ of additional demand due to rebidding of controllable withdrawals (rebids priced high enough to be scheduled accounted for 10.3 TJ on EGP, 1.2 TJ on MSP and 4 TJ in the hub).

Adelaide

In Adelaide, low wind generation drove high GPG demand across the week, particularly increasing upstream demand on the SEAGas pipeline. Alongside the majority of supply to the market being sourced from the MAP (see figure 3.3), reduced ex ante quantities scheduled on SEAGas occurred on a number of days.[26] This coincided with increases to price forecasts across the provisional and ex ante scheduling periods, and drove ex ante prices to between $21/GJ to $28.01/GJ from 7-10 July.[27]

As the majority of capacity offered to the market was supplied by GPG gentailers, rebidding by these participants had a significant impact on the changes in quantities being supplied on SEAGas and MAP. In addition to changing these changing offers, industrial participants supplying gas on the MAP also contributed to a reduction in lower priced offers available in ex ante schedules, with relatively stable industrial demand across forecast schedules.

While there was a significant increase in flows south from Queensland on both the MAP and MSP, this did not necessarily translate to cheaper supply being made available to the markets. Rebidding across GPG gentailer portfolios indicated gas was mostly likely being reserved for upstream generation requirements in all southern regions, with reductions in capacity being offered and/or increases in STTM offer prices coinciding with the location of generation assets. This also had an apparent effect on SEAGas offers, with reductions to the availability of cheaper capacity also coinciding with particularly high Victorian market prices from 6 July. With moderate GPG demand in Queensland over the same period (6-9 July) alongside elevated prices in the Brisbane and Wallumbilla gas markets, this may also have influenced price increases affecting commodities flowing south.

Shifts in ex ante prices from D-2 provisional forecasts were particularly high on 8 July (up $7/GJ to $25.20/GJ ex ante) and 9 July (up $8/GJ to $28/GJ ex ante), with the latter exceeding a significant price reporting threshold.[28]

On 9 July, the driver of the $8/GJ increase in the ex ante pricing schedule was primarily an upwards shift in offer prices, alongside a 2.2 TJ increase in (mostly uncontrollable) demand. Offers priced between $0-5/GJ and $10-15/GJ declined in the ex ante schedule.[29]

The AER will investigate and publish a significant price variation report on the event.

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[26] Compared to D-2 forecast schedules, reduced supply quantities on SEAGas in the ex ante schedule occurred on 4, 6, 8 and 9 July.

[27] Compared to D-2 forecast schedules, ex ante prices increased by $4.99/GJ on 6 July, $7/GJ on 8 July and $8/GJ on 9 July.

[28] When there is a variation of greater than $7/GJ between the D-2 price and ex ante (D-1) price in the STTM.

[29] Quantities removed from between $0-5/GJ were linked to rebidding by industrial and trader participants, while rebids removing $15-20/GJ offers were linked to GPG gentailer, industrial and trader participants. Participant classifications in Adelaide are: GPG Gentailer (AGL, Alinta Energy, EnergyAustralia, Origin, Shell Retail and Snowy Hydro), Industrial (Adelaide Brighton Cement, Boortmalt, Brickworks, Coopers, CSR Building Products, Infrabuild, Master Butchers, Michell Wool, O-I International, SA Water, Tarac Technologies and Visy) and Trader (Eastern Energy).

1. Victorian Declared Wholesale Market

In the Victorian gas market, gas is priced five times daily at 6 am, 10 am, 2 pm, 6 pm and 10 pm. The imbalance weighted price on a gas day tends towards the 6 am price[30] which is the schedule at which most gas is traded.

The main drivers[31] of price are demand forecasts and bids to inject or withdraw gas from the market. Figures 1.1 to 1.4 below show the daily prices, demand forecasts[32], and injection/withdrawal bids for each of the five pricing schedules. Figure 1.5 provides information on which system injection points were used to deliver gas, in turn indicating the location and relative quantity of gas injection bids cleared through the market.

Ancillary payments for gas injected above the market price are shown above in figure 3.

Figure 1.1: Prices by schedule ($/GJ)

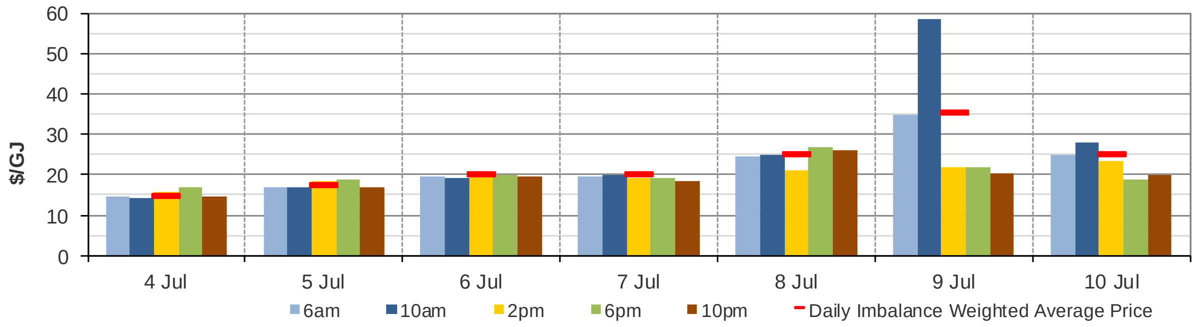
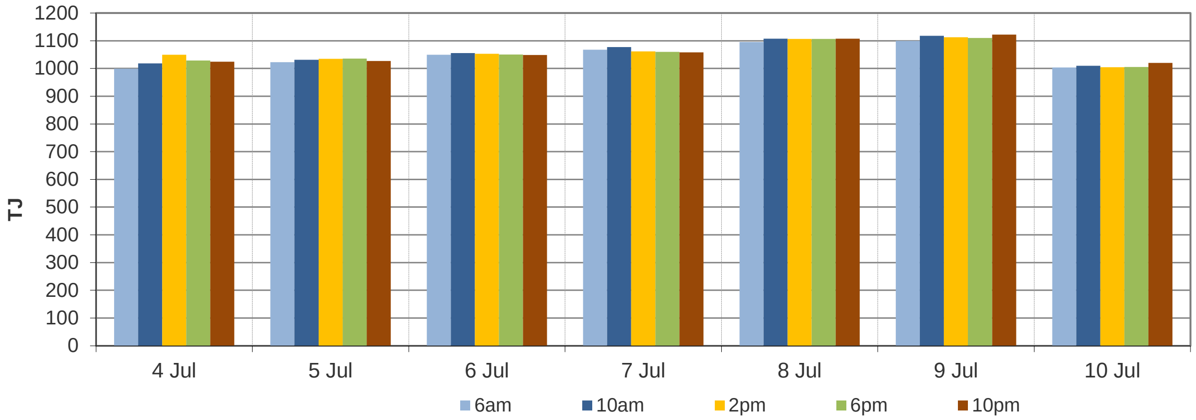


Figure 1.2: Demand forecasts (TJ)



30 Prices for subsequent schedules are applied only to the differences in scheduled quantities (imbalances) to calculate the weighted price. The 6 am price applies to the entire scheduled quantity in the initial schedule.

31 The price might also be affected by transmission or production (contractual) constraints limiting how much gas can be delivered from a locale or System Injection Point (SIP) from time to time.

32 These are Market Participants' aggregate demand forecasts adjusted for any override as applied by AEMO from time to time. These forecasts must be scheduled and cannot respond to price like withdrawal bids.

Figure 1.3: Injection bids by price bands (TJ)

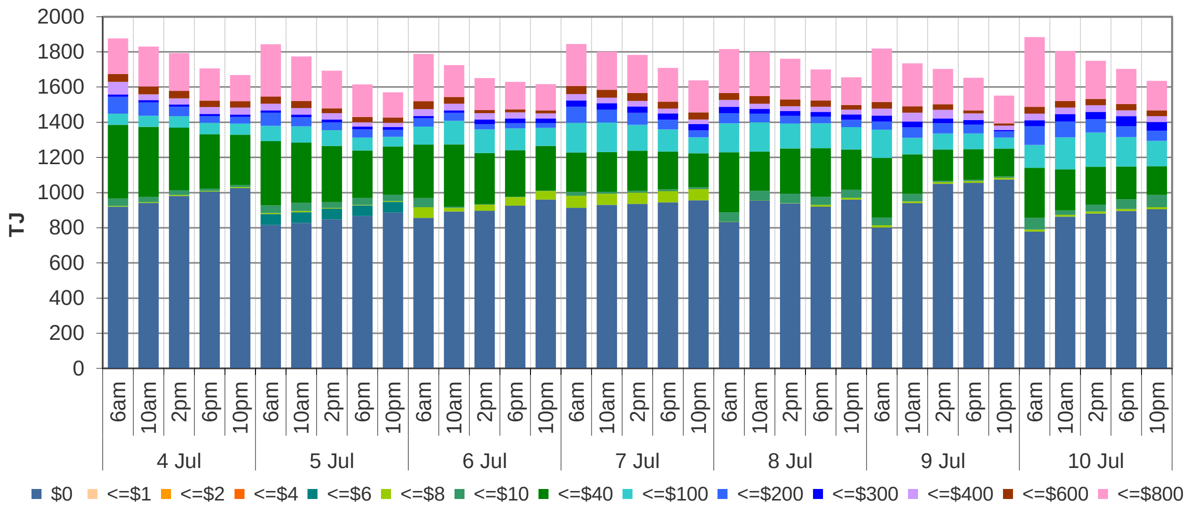


Figure 1.4: Withdrawal bids by price bands (TJ)

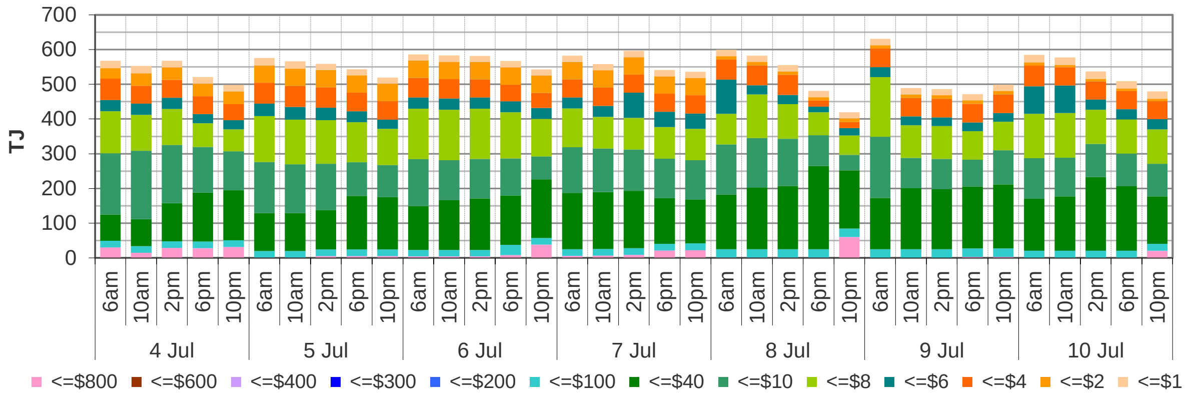
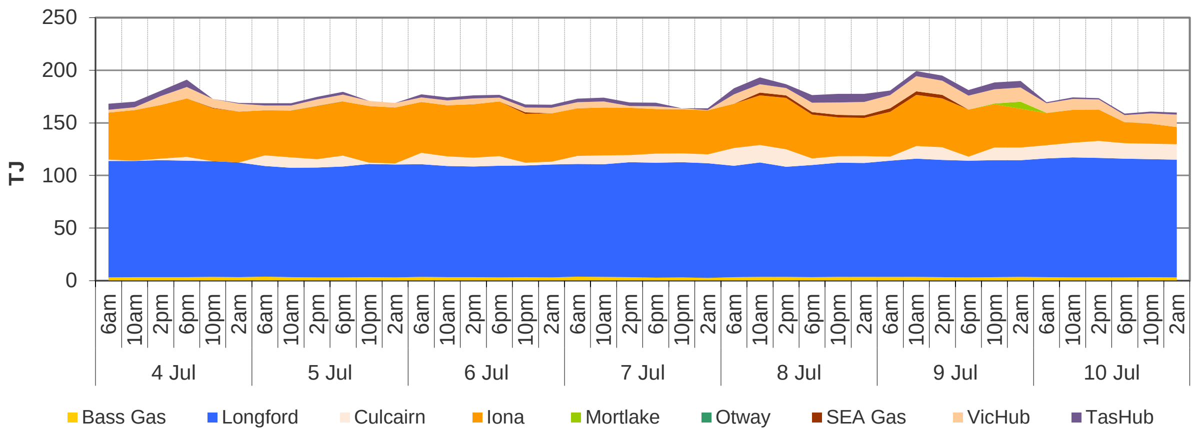


Figure 1.5: Metered Injections by System Injection Point (TJ)



Note that in figure 1.5, the last 8-hour schedule from 10 pm has been separated into two 4-hour blocks to provide a consistent comparison with earlier scheduled injection volumes.

2. Sydney STTM

In each STTM hub, a daily gas price is calculated before the gas day (the ex ante price) and after the gas day (the ex post price). The main drivers of these prices are participant demand forecasts, and offers to inject or bids to withdraw gas traded at the hub.[33] Divergences in ex ante and ex post prices for a gas day may occur due to differences in scheduled (forecast) and allocated (actual) quantities. Pipeline acronyms are defined in the user guide.

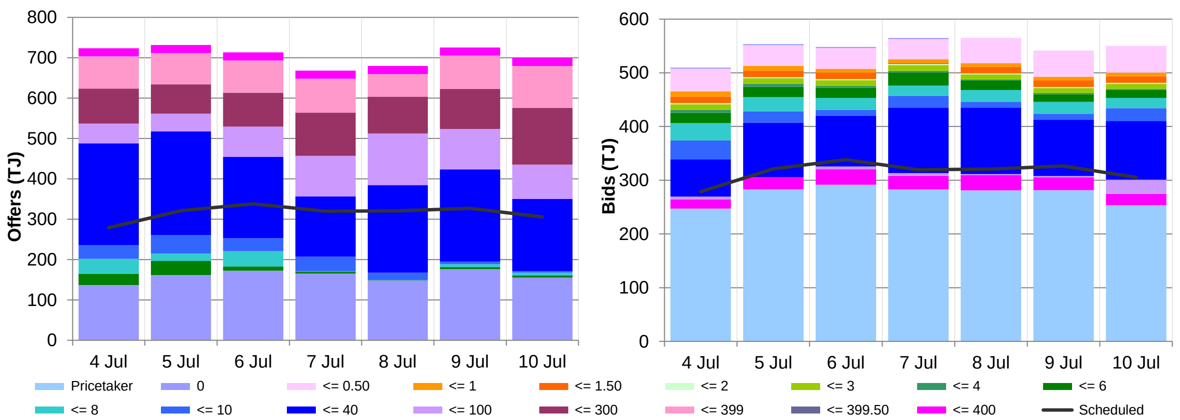
Market Operator Service balancing gas (MOS) payments arise because the amount of gas nominated on pipelines for delivery on a gas day will either exceed or fall short, by some amount, of the amount of gas consumed in the hub. In such circumstances, MOS payments are made to participants for providing a service to park gas on a pipeline or to loan gas from a pipeline to the hub.[34]

Figures 2.1 and 2.2 show daily prices, demand, offers and bids. Figures 2.3 and 2.4 show gas scheduled and allocated on pipelines to supply the hub, indicating the location and relative quantity of gas offers across pipelines and also the amount of MOS allocated for each pipeline.

Figure 2.1: SYD STTM daily ex ante and ex post prices and quantities

	Sun	Mon	Tue	Wed	Thu	Fri	Sat
Ex ante price ($/GJ)	14.10	15.45	20.00	27.56	26.88	20.75	26.99
Ex ante quantity (TJ)	279	321	338	320	321	327	305
Ex post price ($/GJ)	14.75	15.45	21.00	29.78	28.99	22.50	28.00
Ex post quantity (TJ)	291	320	343	333	329	344	314

Figure 2.2: SYD daily hub offers and daily hub bids in price bands ($/GJ)



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33 The main driver of the amount of gas scheduled on a gas day is the 'price-taker' bid, which is forecast hub demand that cannot respond to price and which must be delivered, regardless of the price.

34 MOS service payments involve a payment for a MOS increase service when the actual quantity delivered exceeds final gas nominations for delivery to a hub, and a payment for a MOS decrease service when the actual quantity delivered is less than final nominations. As well as a MOS 'service' payment, as shown in figure 2.4, MOS providers are paid for or pay for the quantity of MOS sold into the market or bought from the market (MOS 'commodity' payments/charges).

Figure 2.3: SYD net scheduled and allocated gas hub supply (excluding MOS)

Figure 2.3 shows the daily scheduled and allocated quantities sorted by facility for Sydney this week. For a more detailed description of this figure, please refer to the user guide.

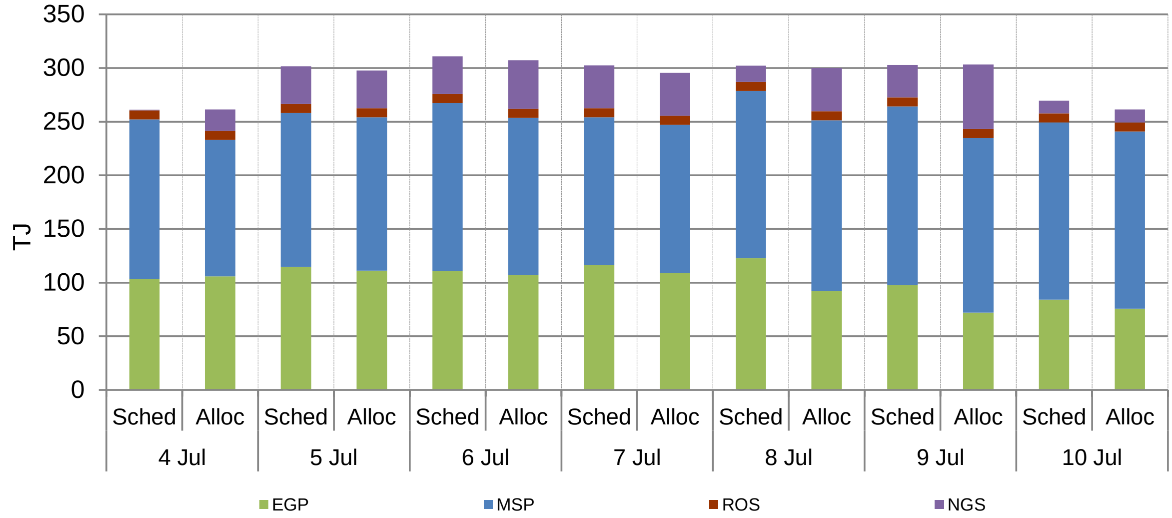
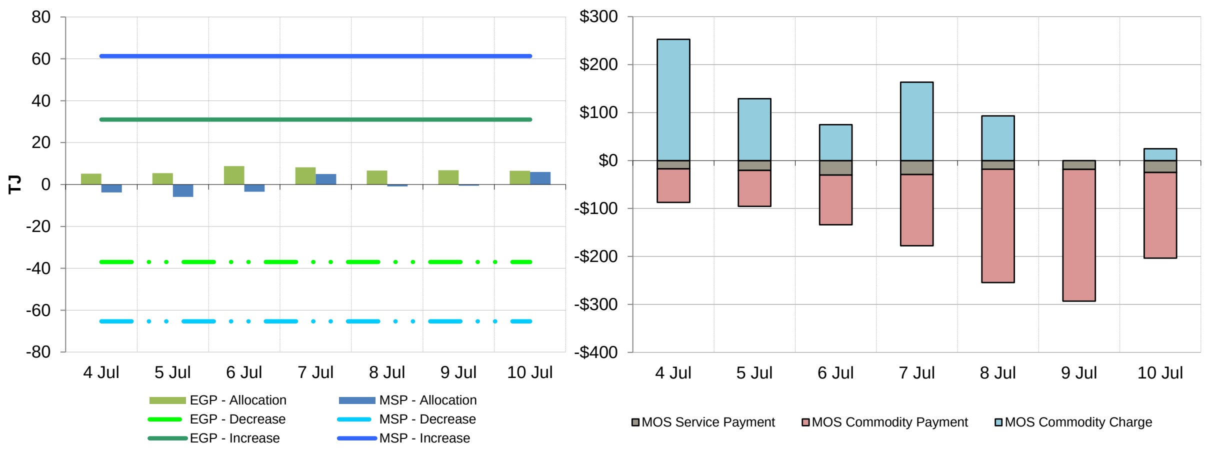


Figure 2.4: SYD MOS allocations (TJ), service payments and commodity payments/charges ($000)[35]



35 The commodity cost of MOS illustrated on the right of the figure represents the commodity quantity at the D+2 ex ante price. Commodity payments and charges for a given gas day relate to quantities traded two days earlier. That is, the commodity cost for services provided on Sunday will appear in the chart for Tuesday, when the D+2 price is set. In contrast, service payments are shown alongside the day they occurred.

3. Adelaide STTM

The Adelaide STTM hub functions in the same way as the Sydney STTM hub. The same data that was presented for the Sydney hub is presented for the Adelaide hub in the figures below.

Figure 3.1: ADL STTM daily ex ante and ex post prices and quantities

	Sun	Mon	Tue	Wed	Thu	Fri	Sat
Ex ante price ($/GJ)	13.49	14.99	19.00	21.00	25.20	28.00	28.01
Ex ante quantity (TJ)	72	87	81	79	78	81	67
Ex post price ($/GJ)	13.49	14.80	19.00	21.00	25.20	28.00	28.01
Ex post quantity (TJ)	71	86	81	82	80	82	67

Figure 3.2: ADL daily hub offers and daily hub bids in price bands ($/GJ)

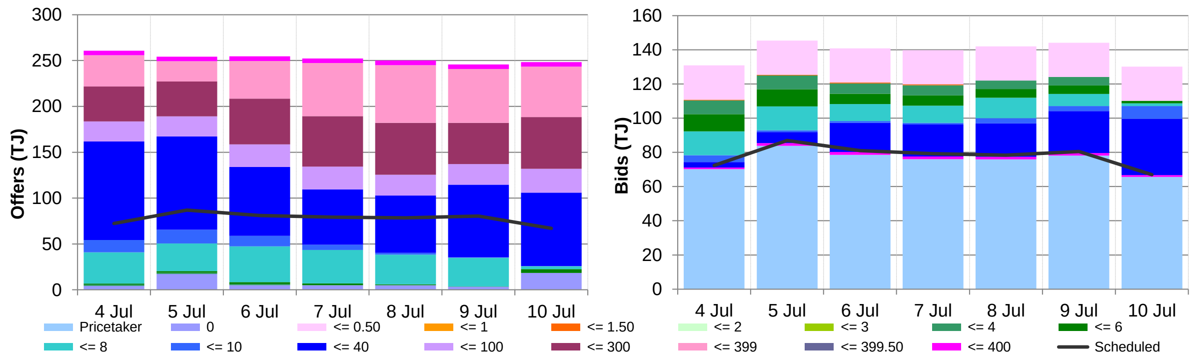


Figure 3.3: ADL net scheduled and allocated gas hub supply (excluding MOS)

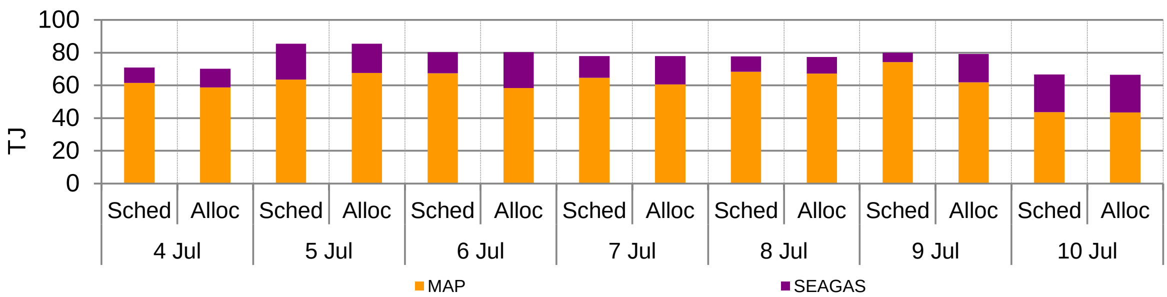
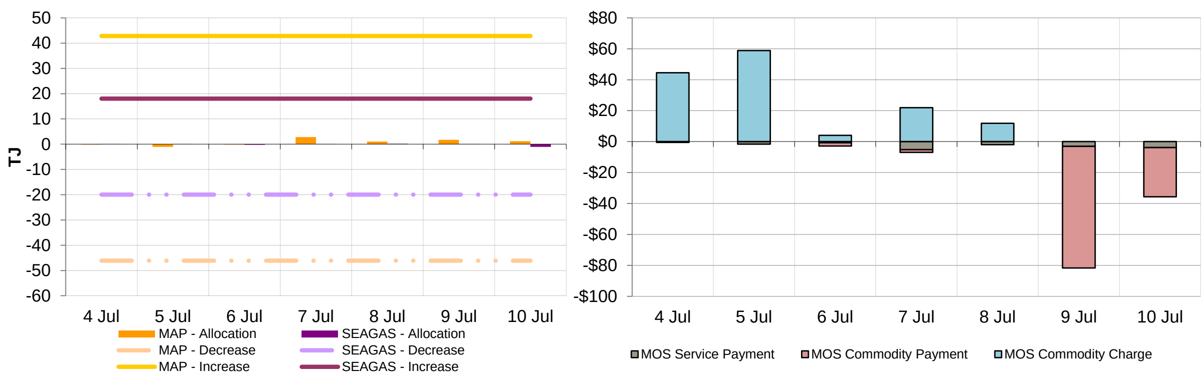


Figure 3.4: ADL MOS allocations (TJ), service payments and commodity payments/charges ($000)



4. Brisbane STTM

The Brisbane STTM hub functions in the same way as the Sydney STTM hub. The same data that was presented for the Sydney hub is presented for the Brisbane hub in the figures below.

Figure 4.1: BRI STTM daily ex ante and ex post prices and quantities

	Sun	Mon	Tue	Wed	Thu	Fri	Sat
Ex ante price ($/GJ)	13.50	14.50	18.50	19.10	20.08	18.70	16.35
Ex ante quantity (TJ)	85	102	100	98	97	98	78
Ex post price ($/GJ)	13.50	14.40	15.98	19.10	18.20	17.50	15.25
Ex post quantity (TJ)	82	98	97	95	86	92	73

Figure 4.2: BRI daily hub offers and daily hub bids in price bands ($/GJ)

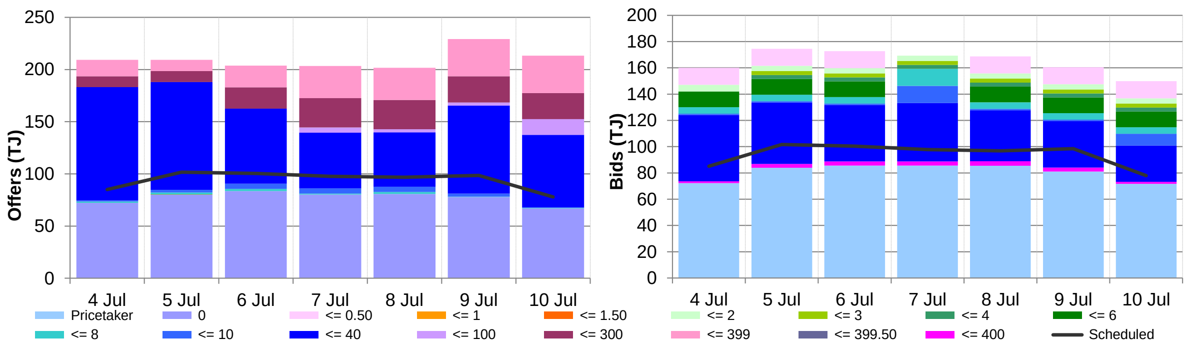


Figure 4.3: BRI net scheduled and allocated gas hub supply (excluding MOS)

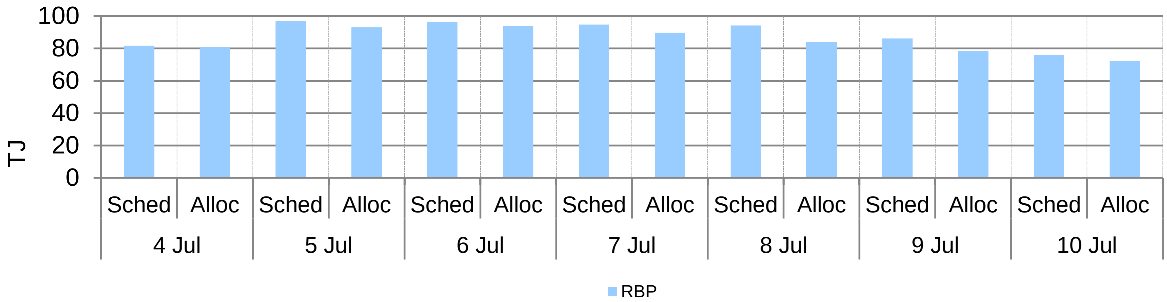
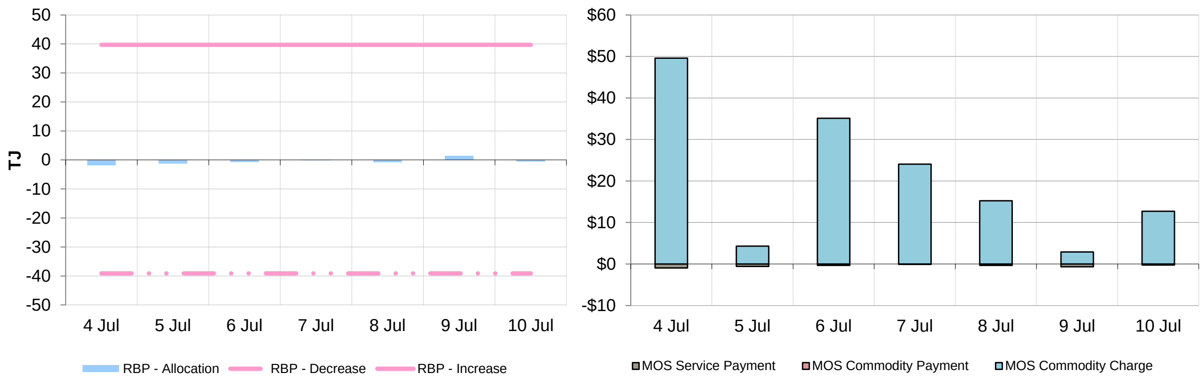


Figure 4.4: BRI MOS allocations (TJ), service payments and commodity payments/charges ($000)



5. National Gas Bulletin Board

Figure 5.1 shows average daily actual flows for the current week[36] from the Bulletin Board (changes from the previous week's average are shown in brackets). Average daily prices[37] are provided for gas markets and gas supply hubs. Average daily quantities are provided for gas powered generation for each region.

Figure 5.1: Gas market data ($/GJ, TJ); Bulletin Board flows (TJ)[38]

Totals	Current Week	Change (TJ)
Domestic gas flows	2212	(+226)
Export gas flows	3363	(-140)
Gas production	5383	(+68)
GPG gas usage	599	(+165)
Pipelines		
Queensland		
Gladstone		
APLNG	1552	(-17)
GLNG	1113	(-106)
QGP	138	(+2)
WGP	697	(-17)
Mt Isa		
CGP	84	(+0)
Brisbane		
RBP	91	(-2)
South West		
SWQP	24	(-16)
Wallumbilla		
BWP	171	(+1)
CRWP	-68	(-57)
DDP	114	(+11)
QGP (WAL)	14	(+2)
RBP (WAL)	-110	(-37)
SWQP (WAL)	319	(+100)
New South Wales		
MSP	287	(+63)
EGP	209	(-22)
Victoria		
LMP	740	(+55)
SWP	263	(+43)
South Australia		
MAP	229	(+35)
SEAGas	82	(+16)
Tasmania		
TGP	40	(+4)
Storage (held volume)		
Moomba LDB	15128	(-74)
Iona UGS	12305	(-1964)
LNG Storage Dandenong	329	(-8)
Silver Springs	19876	(-169)
Roma UGS	38192	(-469)

36 **Domestic gas flows** are calculated as the total of: **SA** = MAP + SEAGAS; **VIC** = SWP + LMP + (flows towards Victoria on the 'NSW-VIC interconnect'); **NSW/ACT** = EGP + MSP; **TAS** = TGP; **QLD (Brisbane)** = RBP; **QLD (Mt Isa)** = CGP; and **QLD (Gladstone)** = QGP.
Export gas flows are calculated as the total of: the APLNG pipeline; the GLNG pipeline; and the Wallumbilla to Gladstone pipeline.
GPG volumes may include gas usage that does not show up on Bulletin Board pipeline flows.

37 GSH supply is the average daily volume of gas 'traded', while price is a volume weighted average. Optional hub services (for compression and redirection) are shown separately from commodity trades.

38 Net flows are shown for Bulletin Board facilities, as outlined in the user guide.

6. Gas Supply Hub

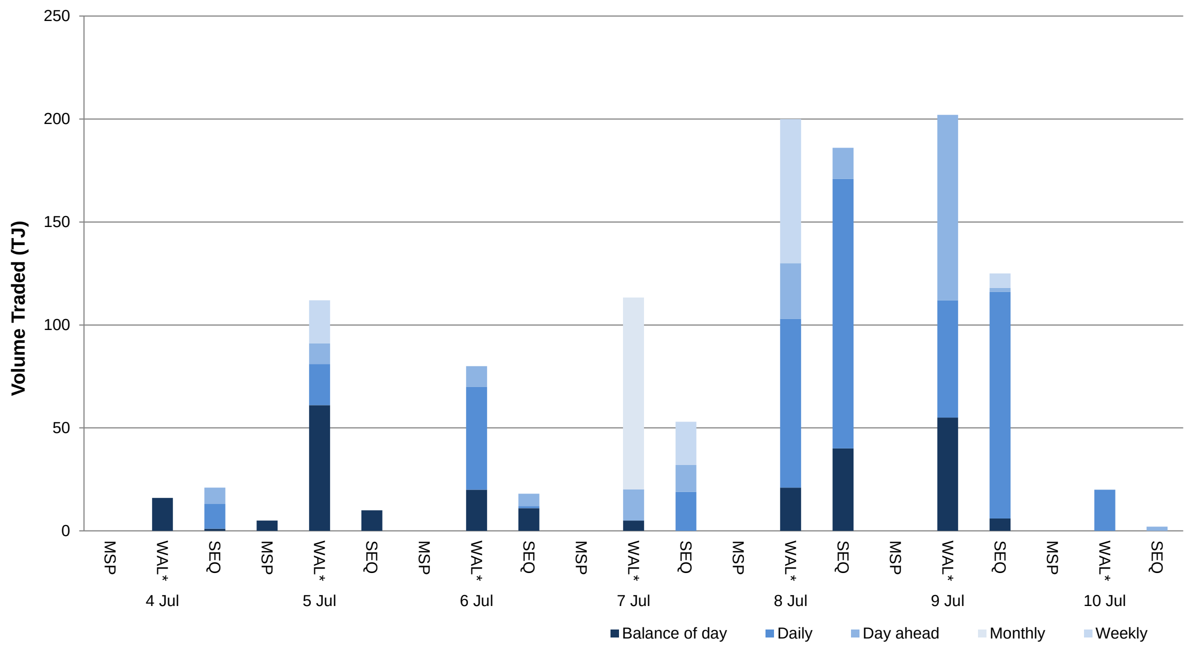
The gas supply hub was established at Wallumbilla in March 2014 to facilitate the voluntary trading of gas between participants, with products listed for sale and purchase at delivery points on three major connecting pipelines. There are separate products for each trading location and delivery period (daily, day-ahead, balance-of-day, weekly and monthly products).[39]

The Moomba hub commenced operation from June 2016 to further facilitate trading on the **MAP** and **MSP**, with trading between the two hubs on the SWQP via a spread product (representing the price differential between the hubs). From October 2016, the addition of a Wallumbilla Compression Product was introduced to facilitate the supply hub's transition from three different trading locations into one. From March 2017, Wallumbilla transitioned into an optional hub services model, replacing the three trading locations (QGP, SWQP and RBP) with a single product at Wallumbilla **(WAL)** and an in-pipe RBP trading location at South East Queensland **(SEQ)**. On 28 January 2021, trading locations at Wilton (Sydney) and Culcairn (Victoria) were introduced.

This week there were 110 trades for 1163.2 TJ of gas at a volume weighted price of $13.81/GJ. These consisted of 73 trades at WAL (743.2 TJ at $14.60/GJ), 36 trades at SEQ (415 TJ at $12.35/GJ) and 1 trade at MSP (5 TJ at $18.25/GJ). There were 3 spread trades this week between SEQ and WAL.

Figure 6.1 shows the quantity of gas traded by product type for each trading day on pipeline trading locations in the Wallumbilla and Moomba Gas Supply Hubs.[40]

Figure 6.1: GSH traded quantities



39 Additional information on trading locations and available products is detailed in the user guide.

40 Non-netted (off-market) trades, allowing the selection of specific delivery point at a trading location, are included with other Wallumbilla trades (WAL*). Non-netted trades at Moomba are shown separately (MOO) from MAP and MSP.

7. Day Ahead Auction

The DAA is a centralised auction platform providing the release of contracted but un-nominated transportation capacity on designated pipelines and compression facilities across eastern Australia. The auction, enables transportation facility users to procure residual capacity on a day-ahead basis after nomination cut-off, with a zero reserve price and compressor fuel provided.

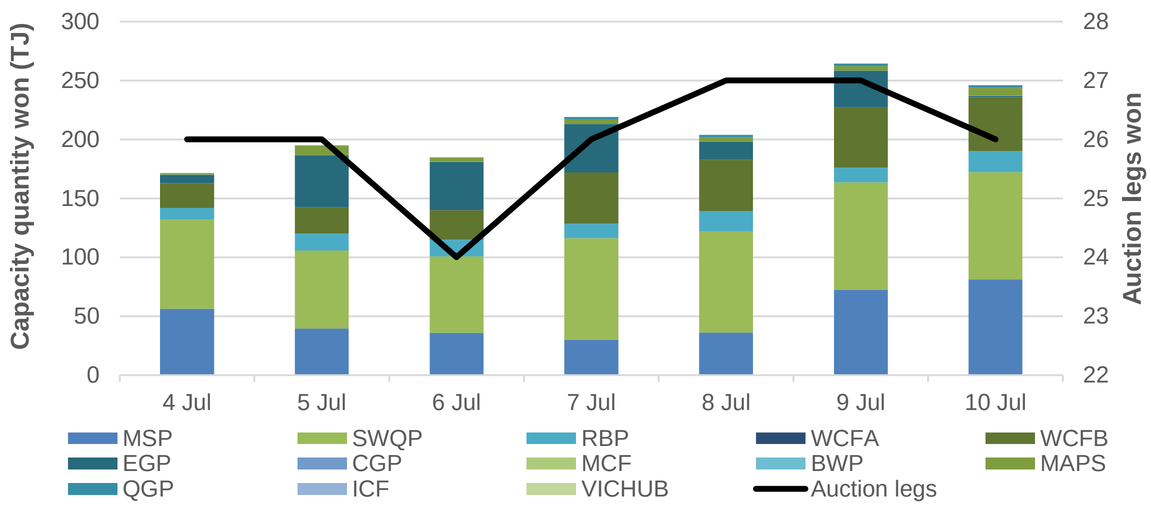
Participants may bid in to the DAA in order to procure the following services:

- park services;
- forward haul pipeline services with products offered in both directions on bi-directional pipelines;
- interruptible backhaul services; and
- stand-alone compression services.

This week, 16 participants took part in the DAA, winning 1635 TJ of capacity across 11 different facilities.

Figure 7.1 shows the quantities of gas and auction legs won through the DAA by gas date, with gas deliverable up to the level of capacity procured. Auction legs reflect each individual facility transaction.[41]

Figure 7.1: DAA traded quantities and auction legs won



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[41] Additional information is available in the user guide to the AER gas weekly report.