Market analysis

17 JULY - 23 JULY 2005

Spot prices for the week were similar to the previous week, and averaged $36/MWh in South Australia, $31/MWh in Victoria, $29/MWh in New South Wales and $22/MWh in Queensland.

In Tasmania the spot price averaged $117/MWh, up slightly on the previous week.

The price volatility index was higher than for the previous week across the mainland regions. In Tasmania, the volatility index reduced further, with the spot price only varying between $93/MWh and $130/MWh.

Turnover in the energy market was around $134 million, while the total cost of ancillary services for the week was $440,000 or 0.3 per cent of the total turnover in the energy market. The cost for ancillary services in Tasmania totalled $128,000 or 0.5 per cent of the energy market turnover for that region.

Demand forecasts produced 4 and 12 hours ahead varied from actual by more than 5 per cent in around a quarter of all trading intervals across the market with close to two thirds of trading intervals in South Australia affected. The maximum error four hours ahead for under-forecasting demand was 17 per cent (or 260 MW) in South Australia, 8 per cent (800 MW) in New South Wales, 7 per cent (90 MW) in Tasmania and 6 per cent (360 MW) in Queensland and Victoria. These errors are similar to the size of the largest unit in most regions. Significant variations between forecast and actual prices occurred in 41 or 12 per cent of all trading intervals.

Energy prices

Figure 1 compares the volume weighted average price with the averages for the previous week, the same quarter last year and for the 2004-05 financial year. Figure 2 sets out national demand and spot prices in each region for each trading interval. Figure 3 compares the weekly price volatility index with the averages for the previous week and the same quarter last year.

Figure 1: volume weighted average spot price for energy market ($/MWh)

	QLD	NSW	VIC	SA	TAS
Last week	22	29	31	36	117
Previous week	18	26	29	36	107
Same quarter last year	27	31	28	36	-
Financial year 2004 - 05	31	46	29	39	-
% change from previous week	▲22%	▲9%	▲5%	▼1%	▲9%
% change from same quarter last year	▼16%	▼9%	10%	▼2%	-
% change from 2003 - 04	▼1%	▲24%	▲7%	0%	-

Figure 2: national demand and spot prices

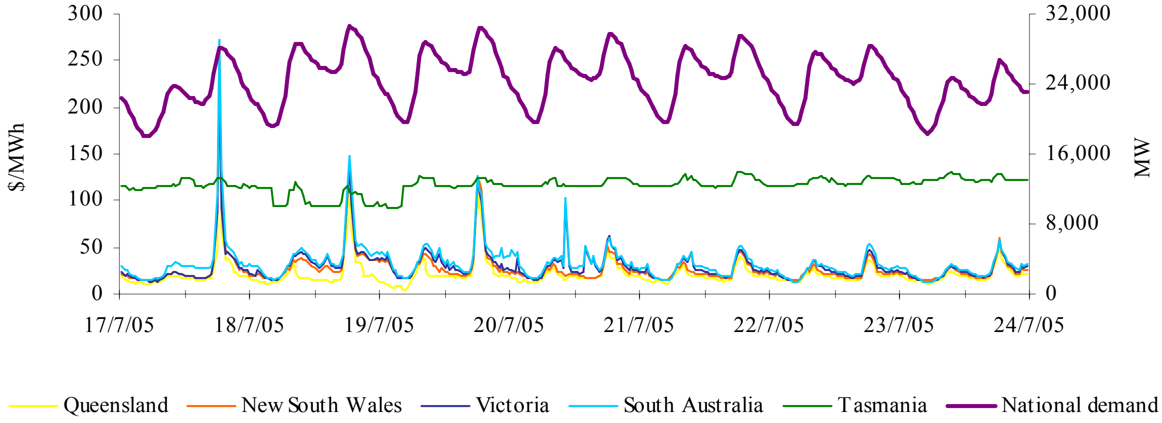


Figure 3: volatility index during peak periods

	QLD	NSW	VIC	SA	TAS
Last week	0.91	0.91	0.77	0.77	0.16
Previous week	0.28	0.46	0.69	0.70	0.24
Same quarter last year	0.64	0.74	0.71	0.56	-

Figures 4 to 8 show the weekly correlation between spot price and demand.

Figure 4: Queensland

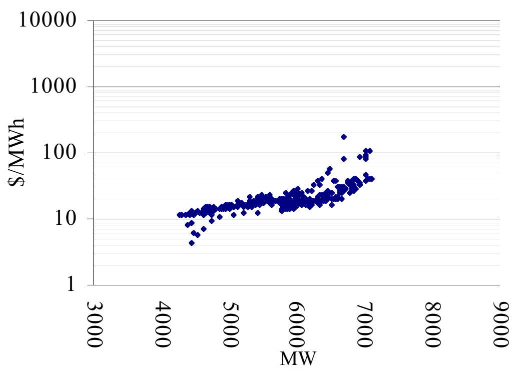


Figure 5: New South Wales

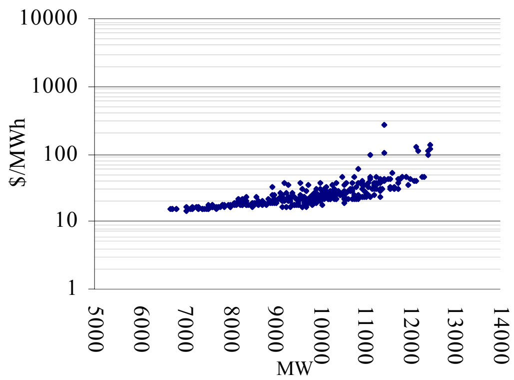


Figure 6: Victoria

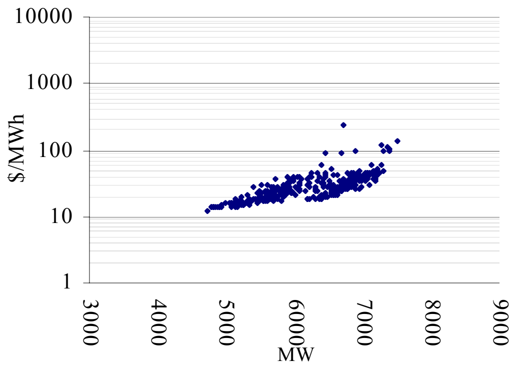


Figure 7: South Australia

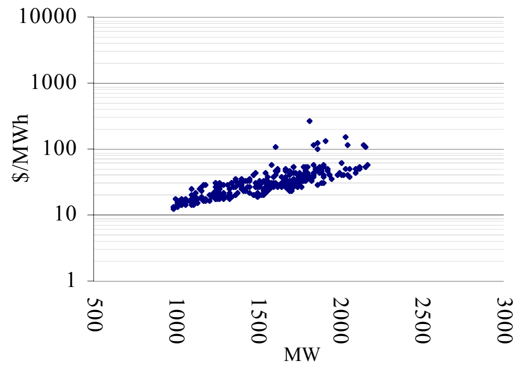
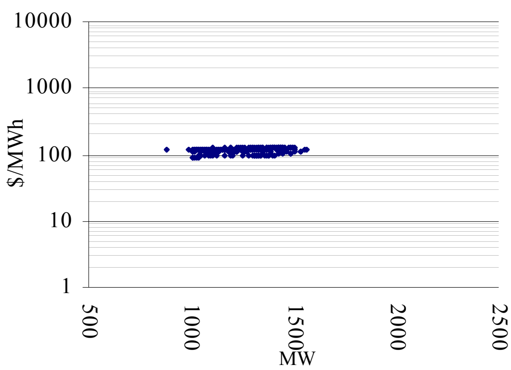


Figure 8: Tasmania



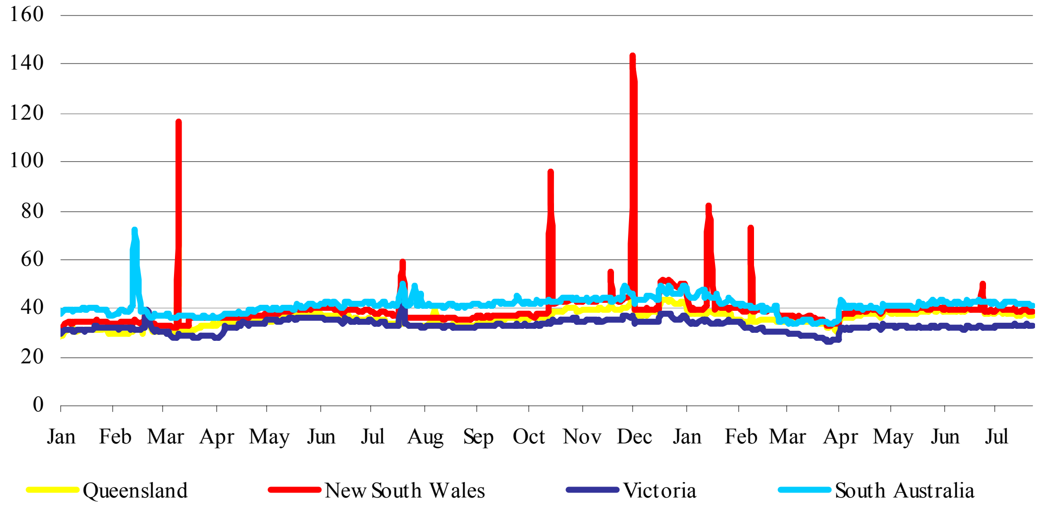
Spot prices peaked at $270/MWh in South Australia and New South Wales, $240/MWh in Victoria and at $180/MWh in Queensland, all on Sunday evening. In Tasmania the spot price peaked at $130/MWh on Saturday morning.

Figure 9 sets out the d-cyphaTrade wholesale electricity price index (WEPI) for each region throughout the week excluding Tasmania. Figure 10 sets out the WEPI since 1 January 2004.

Figure 9: d-cyphaTrade WEPI for the week

	Monday	Tuesday	Wednesday	Thursday	Friday
Queensland	37.89	37.42	37.17	37.24	37.27
New South Wales	39.71	40.22	38.79	38.88	38.78
Victoria	32.90	33.46	32.83	33.08	32.84
South Australia	42.31	42.96	42.23	42.00	41.57

Figure 10: d-cyphaTrade WEPI



Reserve

There were no low reserve conditions forecast throughout the week. Figures 11 to 14 show spot price, net imports and limits at the time of weekly maximum demand.

Figures 11 to 14: spot price, net import and limit at time of weekly maximum demand

Figure 11: Queensland

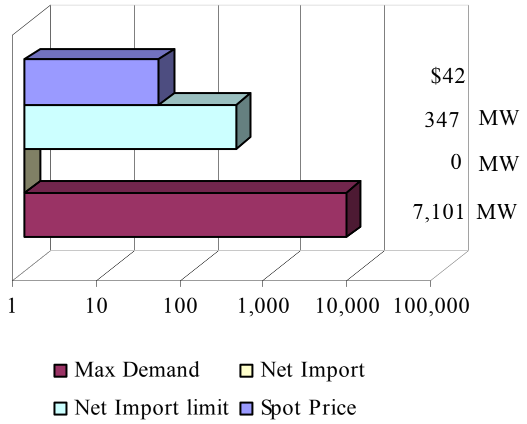


Figure 12: New South Wales

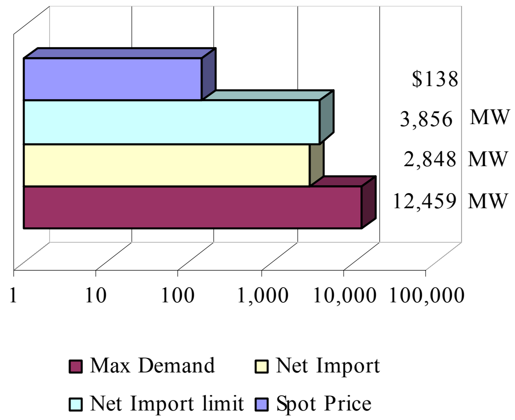


Figure 13: Victoria

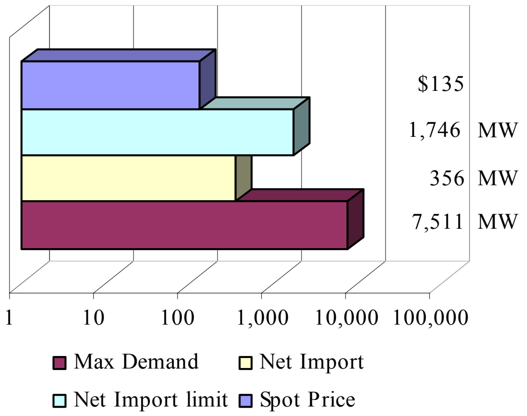
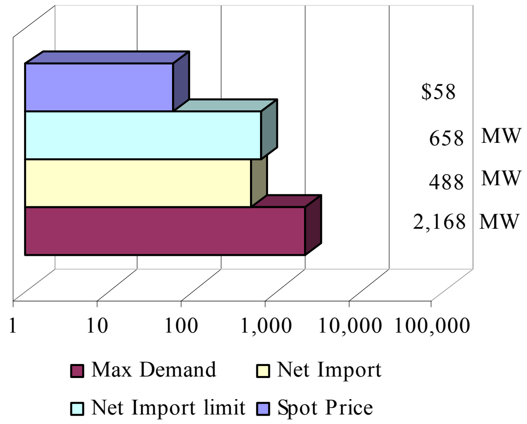


Figure 14: South Australia



In Tasmania the demand reached a maximum of 1,559MW on Monday morning. The spot price at the time reached $119/MWh.

Price variations

There were 41 trading intervals where significant variations between forecast and actual prices occurred, calculated 4 and 12 hours ahead of despatch. Figures 15 to 18 set out the correlation between the actual price and demand and those forecast. The information is presented in terms of the percentage difference from actual. Price differences beyond 200 per cent have been capped.

Figure 15: Queensland

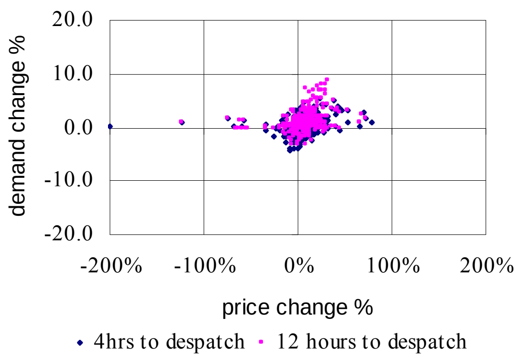


Figure 16: New South Wales

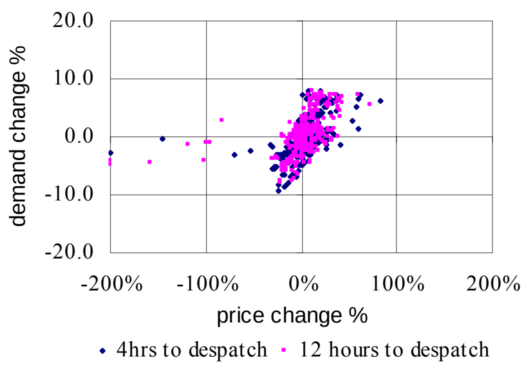


Figure 17: Victoria

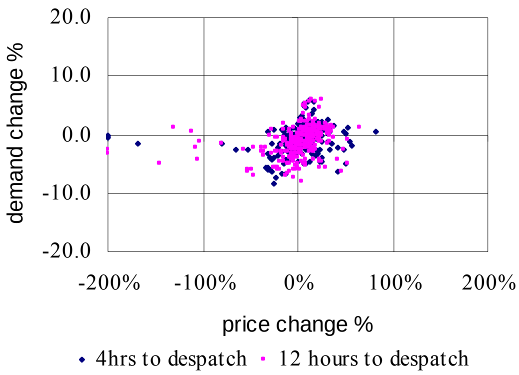


Figure 18: South Australia

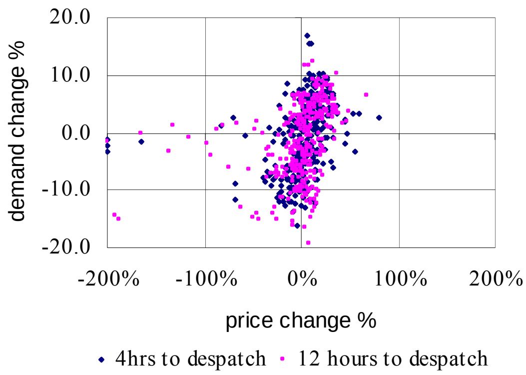


Figure 19: Tasmania

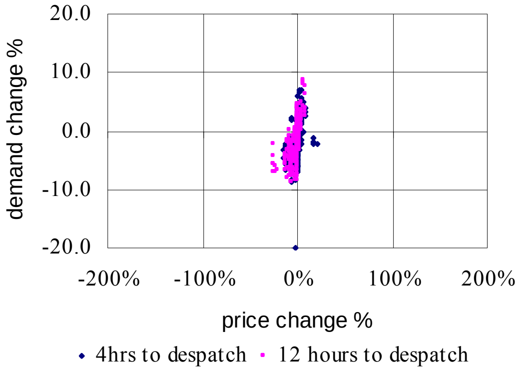
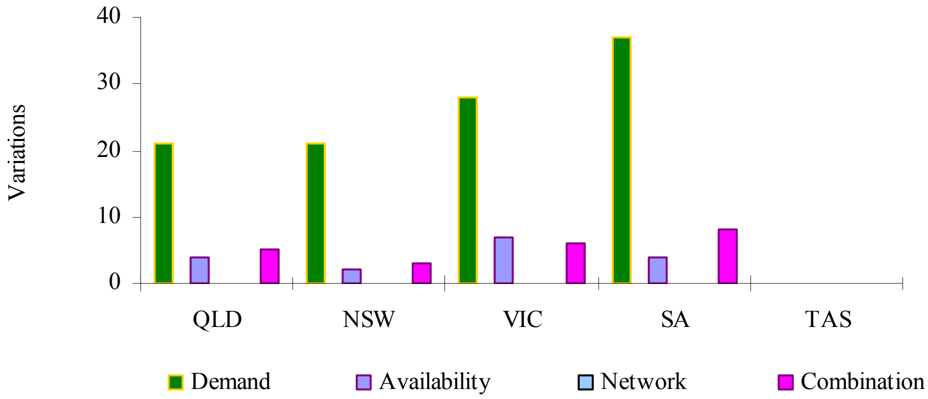


Figure 20 summarises the number and most probable reason for variations between forecast and actual prices.

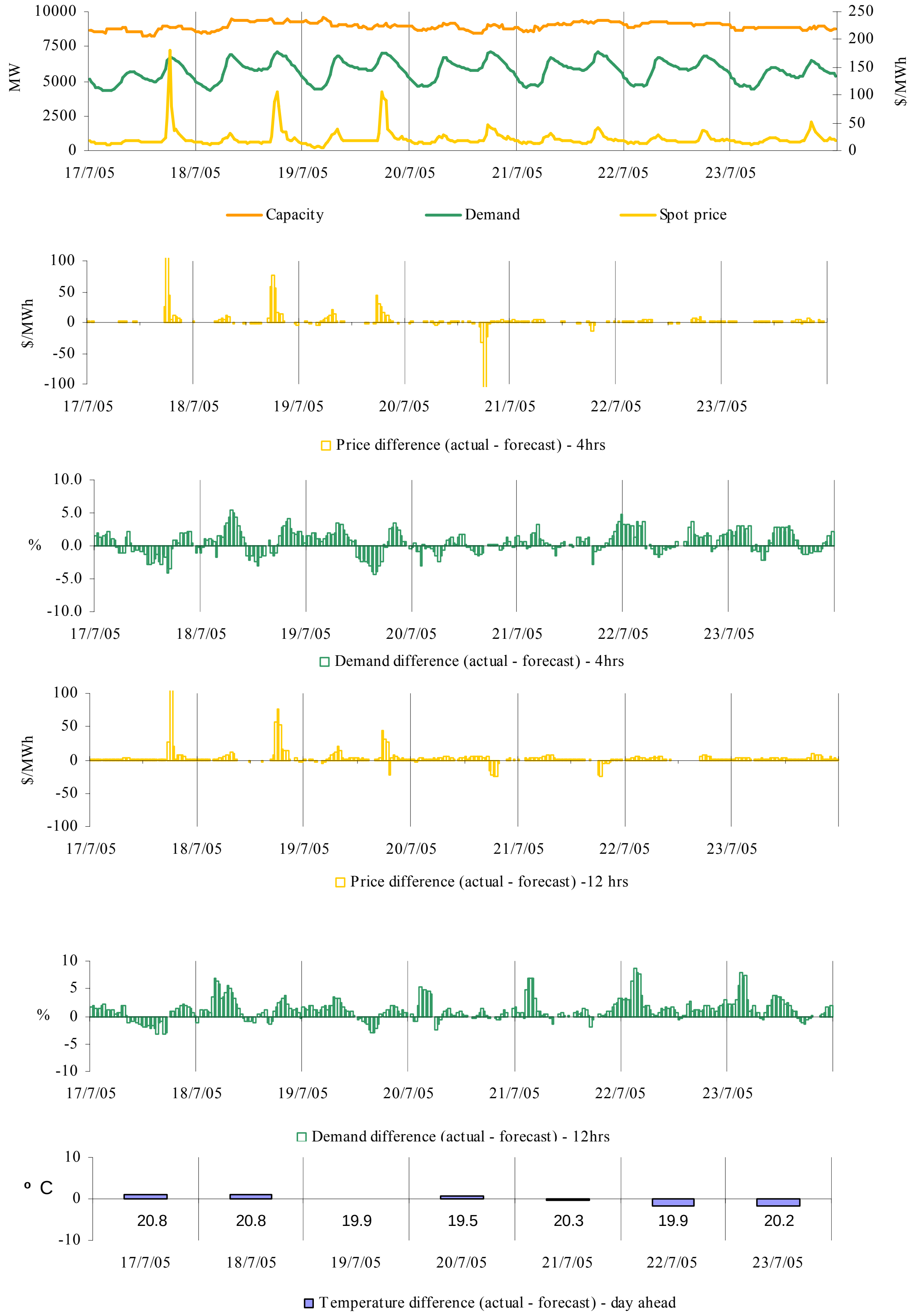
Figure 20: reasons for variations between forecast and actual prices



Price and demand

Figures 21 – 50 set out details of spot prices and demand on a regional basis. They include the actual spot price and demand outcomes and difference graphs both four and twelve hours ahead of despatch on a daily basis. The differences between the maximum temperature and the temperature forecast at around 6.00 pm the day before are also included. Figures 51 - 55 set out, for each region, the extent of capacity offered into the market within a series of price thresholds. Actual price and generation despatched in a region are overlaid.

Figures 21-26: Queensland actual spot price, demand and forecast differences



There were 8 occasions in Queensland where the spot price was greater than three times the weekly average price of $22/MWh. These occurred between 6pm and 6.30pm on Sunday and between 6pm and 7pm on Monday and Tuesday.

Sunday, 17 July

6:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	180.05	38.92	62.64
Demand (MW)	6,687	6,635	6,622
Available capacity (MW)	8,911	8,953	8,963
7:00 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	81.14	37.17	60.72
Demand (MW)	6,683	6,623	6,618
Available capacity (MW)	8,906	8,953	8,963

Conditions at the time saw demand close to forecast, with prices reflecting conditions in New South Wales for most of the period. A rebid at 5.17pm by Tarong Energy saw 185MW of capacity at Wivenhoe shifted from prices of $63/MWh to $9/MWh – committing a unit. The reason given was "alter PB volumes based on latest predespatch". At 6.17pm 15 MW of capacity at Oakey was repriced from $287/MWh to $0/MWh committing another unit. The reason given was "Material change in market conditions." There was no other significant rebidding.

Monday, 18 July

6:00 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	87.00	29.61	29.51
Demand (MW)	6,927	6,908	6,871
Available capacity (MW)	9,214	9,567	9,510
6:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	106.94	29.61	30.11
Demand (MW)	7,069	6,959	6,949
Available capacity (MW)	9,165	9,527	9,510
7:00 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	78.96	23.51	25.33
Demand (MW)	7,031	6,838	6,863
Available capacity (MW)	9,152	9,527	9,510

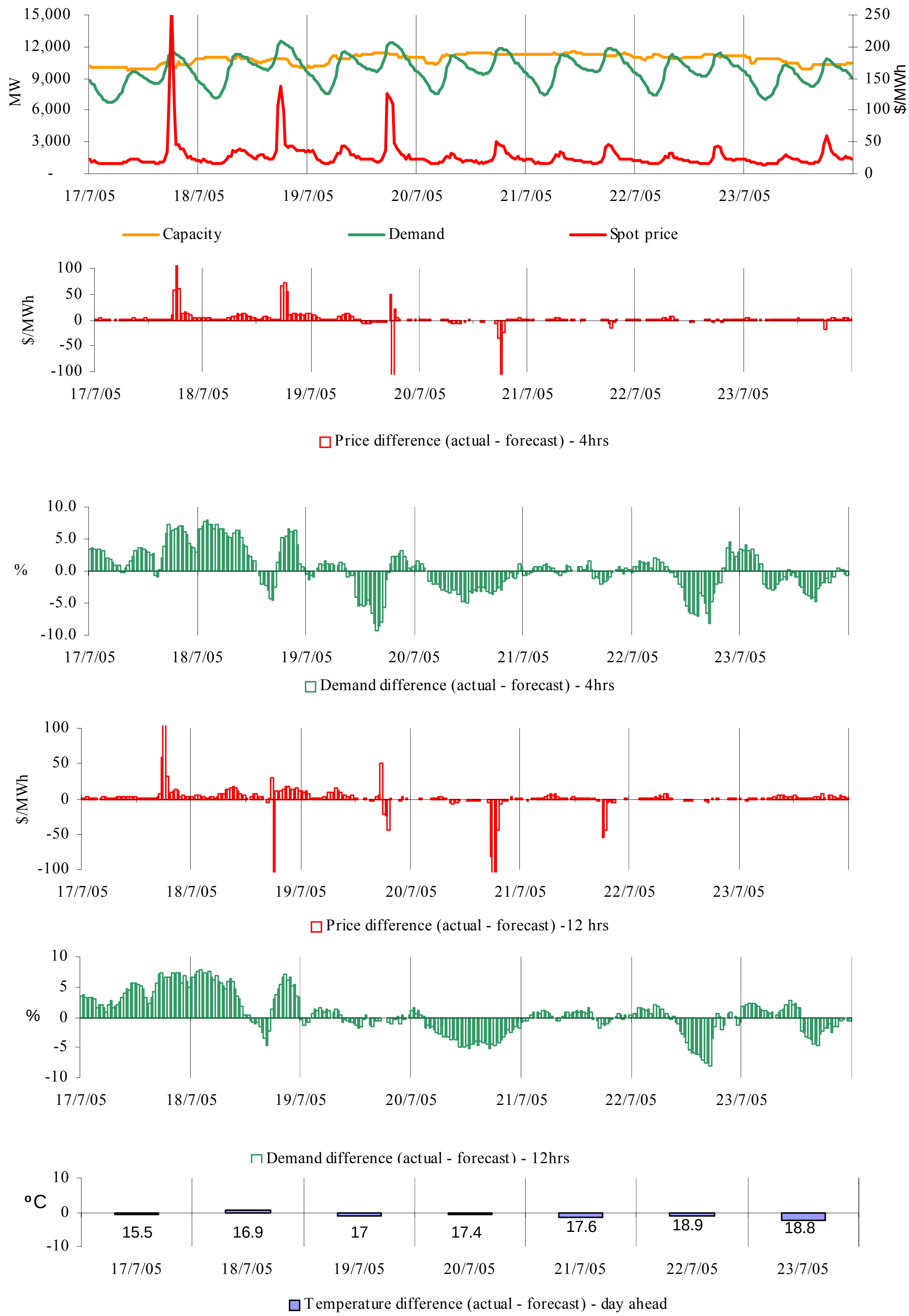
Conditions at the time saw demand up slightly on that forecast. Prices were aligned across the mainland regions for most of this period. Over a number of rebids from 5.30pm, Callide B unit 1 was shut down from 350 MW. This was in part offset by the rebidding of capacity into low prices to commit units at Oakey and Wivenhoe at 5.47pm and 5.59pm respectively. There was no other significant rebidding.

Tuesday, 19 July

6:00 pm	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	105.99	62.64	62.64
Demand (MW)	7,022	7,008	7,002
Available capacity (MW)	8,947	9,307	9,307
6:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	94.19	63.24	63.24
Demand (MW)	7,034	7,054	7,038
Available capacity (MW)	9,012	9,307	9,307
7:00 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	88.99	62.64	62.64
Demand (MW)	7,013	6,965	6,959
Available capacity (MW)	9,127	9,307	9,307

Conditions at the time saw demand and price close to forecast, with prices aligned across the mainland regions. There was no significant rebidding.

Figures 27-32 New South Wales actual spot price, demand and forecast differences



There were 9 occasions in New South Wales where the spot price was greater than three times the weekly average price of $29/MWh. These occurred between 6pm and 7pm on Sunday, Monday and Tuesday.

Sunday, 17 July

6:00 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	96.76	37.64	38.90
Demand (MW)	11,126	10,320	10,310
Available capacity (MW)	10,220	11,170	10,520
6:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	269.28	44.08	76.18
Demand (MW)	11,414	10,716	10,771
Available capacity (MW)	10,350	11,260	10,660
7:00 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	104.03	42.75	71.50
Demand (MW)	11,412	10,682	10,658
Available capacity (MW)	10,090	11,310	10,760

Conditions at the time saw demand around 700MW higher than forecast four hours to despatch. Prices were aligned across the mainland regions for most of this period.

Delta Electricity reduced its availability across its portfolio by around 600MW with rebids made around 4pm and 5.30pm. This included the delayed return to service of Munmorah power station and fixed load rebidding at Vales Point which saw unit 6 bid inflexible for almost an hour. The rebid reasons given were “RTS::Capacity change”, “Enter plant condition::Fixed load change stack emission” and ‘Dust burden”.

With a number of rebids close to despatch, Eraring Energy delayed the return to service of unit 2, reducing its available capacity by as much as 600MW. The unit had been scheduled to return from around 2.30pm, earlier in the afternoon. The rebid reasons given included “Bid rearrangement due to unit failure”, “unit experiencing difficulties” and “unit having difficulties”.

At 5.17pm, Macquarie Generation rebid 200MW across its Bayswater units from prices of $14/MWh to prices around $60/MWh. A further rebid at 5.58pm for the 6.30pm trading interval shifted this capacity to prices around $250/MWh. At 6.30pm a rebid for the 7pm trading interval shifted 200MW of capacity from prices of around $60/MWh to prices around $90/MWh. The rebid reason given on each occasion was ‘RP/Volume Tradeoff – NEMMCO load forecast increased”. The rebid combined with the daily offer saw a reduction in output across the Macquarie Generation portfolio of 510MW during the evening peak. As a result, gas turbines at Valley Power in Victoria, Hallet in South Australia and Oakey in Queensland were all committed.

There was no other significant rebidding.

Monday, 18 July

6:00 pm	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	107.58	42.57	77.43
Demand (MW)	12,171	12,000	11,999
Available capacity (MW)	10,847	11,337	11,547
6:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	138.43	65.19	253.55
Demand (MW)	12,459	12,099	12,098
Available capacity (MW)	10,872	11,337	11,547
7:00 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	98.81	42.64	87.35
Demand (MW)	12,422	11,780	11,962
Available capacity (MW)	10,847	11,337	11,547

Conditions at the time saw demand up to 640MW higher than forecast four hours to despatch. Prices were aligned across the mainland regions for most of this period. Delta Electricity reduced its availability at Vales Point by 490MW with rebids made around 4.30pm and 6pm. The rebid reasons given were "Dust emission limit:: Capacity limit change" and "Precip problems:: Capacity limit". There was no other significant rebidding.

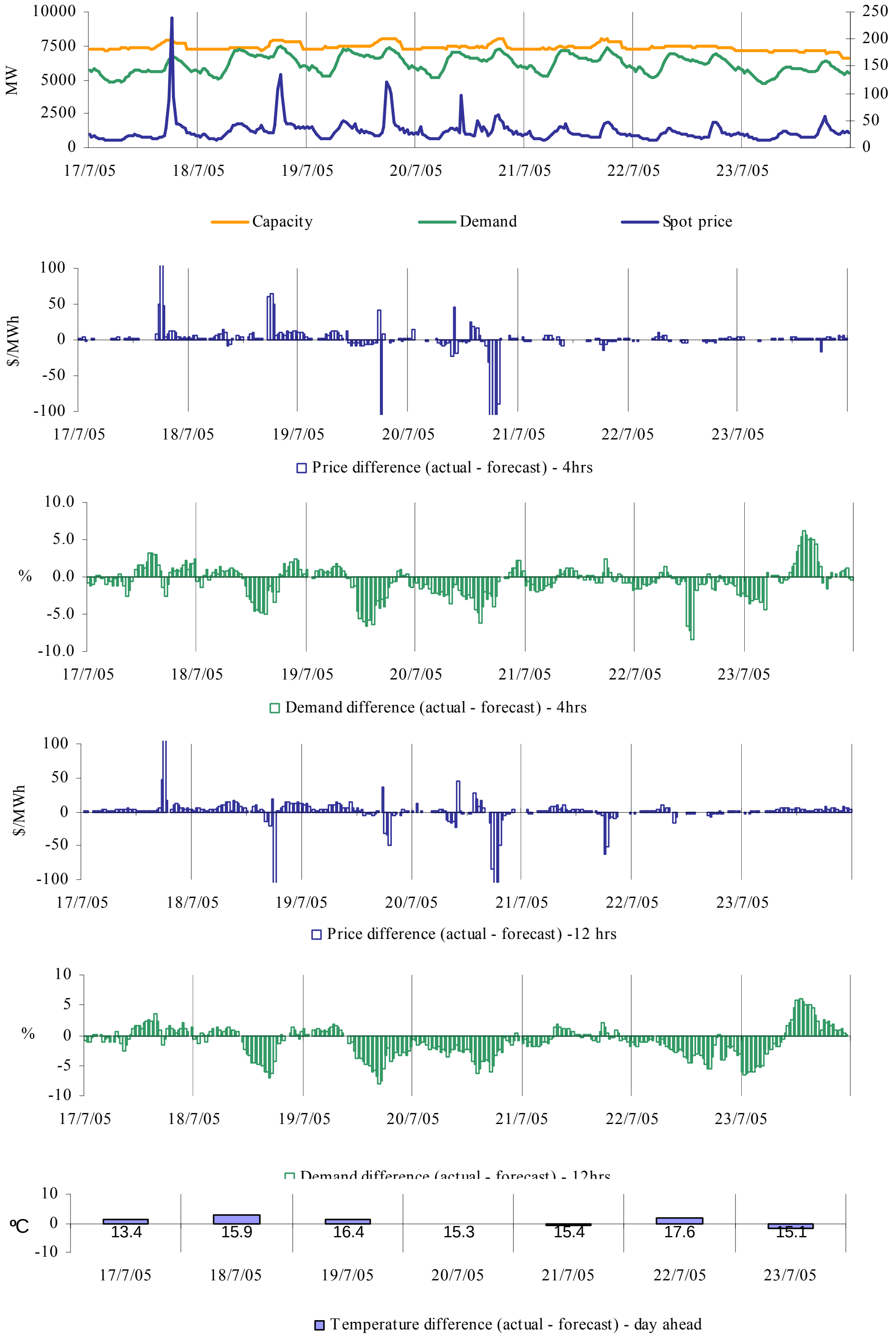
Tuesday, 19 July

6:00 pm	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	125.32	74.64	75.79
Demand (MW)	12,153	12,317	12,158
Available capacity (MW)	11,376	11,445	11,547
6:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	120.24	295.40	141.87
Demand (MW)	12,453	12,477	12,473
Available capacity (MW)	11,343	11,443	11,547
7:00 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	110.42	88.48	133.30
Demand (MW)	12,411	12,262	12,417
Available capacity (MW)	11,343	11,443	11,547

Conditions at the time saw demand and price close to forecast, with prices aligned across the mainland regions.

At around 4pm, Macquarie Generation rebid 610MW of capacity from prices of $14/MWh to $250/MWh. The rebid reason given was "RP/Volume Tradeoff – NEMMCO load forecast reduced". The rebid combined with the daily offer saw a reduction in output across the Macquarie Generation portfolio of almost 930MW during the evening peak. Delta Electricity reduced its availability at Vales Point by 100MW with a rebid at 5.30pm. The rebid reason given was "Dust emission limit:: Capacity limit change". There was no other significant rebidding.

Figures 33-38: Victoria actual spot price, demand and forecast differences



There were 9 occasions in Victoria where the spot price was greater than three times the weekly average price of $31/MWh. These occurred at 6.30pm and 7pm on Sunday, between 6pm and 7pm on Monday, between 6pm and 7pm on Tuesday and at 10.30am on Wednesday.

Sunday, 17 July

6:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	238.64	44.76	80.48
Demand (MW)	6,722	6,682	6,652
Available capacity (MW)	7,858	7,850	7,462
7:00 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	93.17	44.39	76.32
Demand (MW)	6,688	6,614	6,585
Available capacity (MW)	7,809	7,860	7,462

Conditions at the time saw demand in Victoria close to forecast, with prices aligned with neighbouring regions and reflecting conditions in New South Wales.

A rebid at around 9.30am saw 500MW of capacity at Newport committed for the evening peak. The reason given was "Adj to unit commitment due to PD conditions @9.32". Over a number of rebids throughout the day, International Power reduced the availability at Hazelwood by as much as 176MW from that offered at the beginning of the day. Most of this capacity was priced at less than $20/MWh. The rebid reasons included "Draft plant limit", "Firing plant limit", "Plant limit relieved", "Fuel limitation", and "Revised rate of run up capacity".

From around 5.49pm all six Valley Power gas turbines were committed in response to the changing prices, through rebidding 315 MW of capacity priced at $94/MWh and above to zero. The rebid reason given was "change in actual prices". There was no other significant rebidding.

Monday, 18 July

6:00 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	106.67	46.88	88.41
Demand (MW)	7,377	7,524	7,692
Available capacity (MW)	7,902	7,878	7,545
6:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	134.59	70.13	274.62
Demand (MW)	7,511	7,477	7,609
Available capacity (MW)	7,959	7,878	7,535
7:00 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	97.37	47.36	96.63
Demand (MW)	7,378	7,361	7,473
Available capacity (MW)	7,958	7,883	7,515

Conditions at the time saw demand close to forecast, with prices aligned with neighbouring regions and reflecting conditions in New South Wales and Queensland.

Valley Power units 2, 3, 4, 5 and 6 were committed in response to the changing prices, through rebidding 283 MW of capacity priced at $80/MWh and above to zero at around 5.45pm. The rebid reason given was "change in actual prices". There was no other significant rebidding.

Tuesday, 19 July

6:00 pm	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	120.83	79.48	84.10
Demand (MW)	7,277	7,476	7,685
Available capacity (MW)	7,998	7,967	8,054
6:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	110.28	295.15	141.11
Demand (MW)	7,348	7,456	7,586
Available capacity (MW)	8,020	7,967	8,029
7:00 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	99.58	91.36	133.91
Demand (MW)	7,297	7,353	7,459
Available capacity (MW)	8,011	7,817	7,854

Conditions at the time saw demand and price close to forecast, with prices aligned across the mainland regions.

Valley Power units 1, 3, 5 and 6 were committed in response to the changing prices, through rebidding 230 MW of capacity priced at around $400/MWh to zero at around 5.30pm. The reason given was "change in price forecasts". At around 5.30pm 70 MW of capacity at Somerton was committed through rebidding capacity priced at $9,444/MWh to zero. The reason given was "predispatch: forecast price increase". At around 6pm, 400 MW of capacity at Newport was rebid from $9,147MWh to less than $35/MWh. The reason given was "predispatch: forecast price increase". There was no other significant rebidding.

Wednesday, 20 July

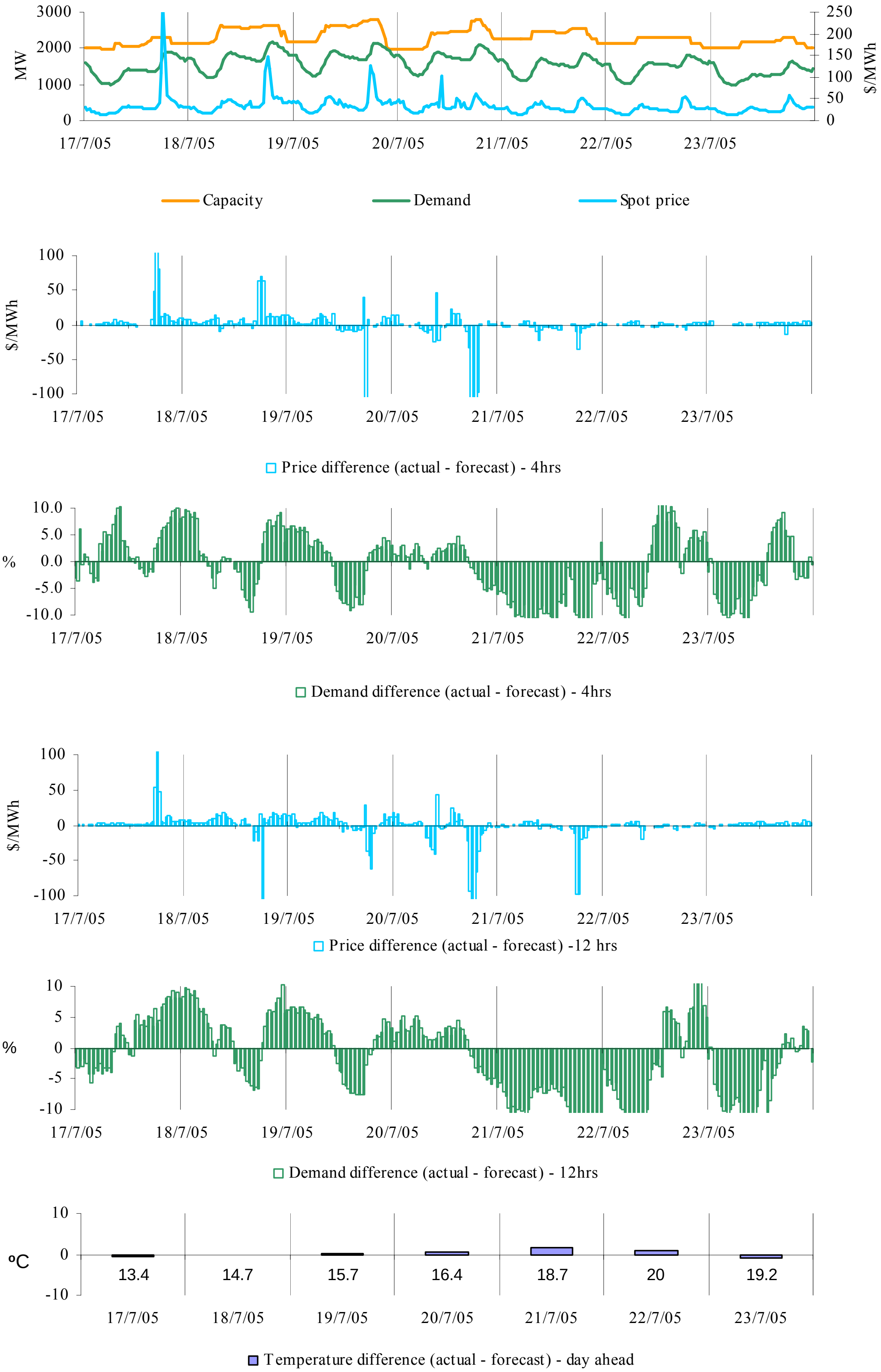
10:30 am	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	95.60	49.90	49.90
Demand (MW)	6,886	7,052	7,059
Available capacity (MW)	7,424	7,492	7,636

Conditions at the time saw demand in Victoria around 150MW below that forecast four hours earlier.

At around 10.10am an unplanned network outage of the Lower Tumut - Murray line in the Snowy region saw the import limit into Victoria reduced from around 1,350MW to 670MW by 10.30am. As a result, flows into Victoria were reducing by around 500MW. Fast start plant at Jeeralang, Eildon, McKay and Angaston all responded. As a result the 5-minute price in Victoria and South Australia rose from around $30/MWh to $290/MWh for one despatch interval. Unit 4 at Torrens Island also responded by rebidding 75MW of capacity from $290/MWh to -$1,000/MWh at 10.18am. The reason given was "Mkt conditions – Gen response to conditions @10.15"

The line was restored and the constraint removed at 10.45am. There was no other significant rebidding.

Figures 39-44: South Australia actual spot price, demand and forecast differences



There were 8 occasions in South Australia where the spot price was greater than three times the weekly average price of $36/MWh. These occurred between 6pm and 7pm on Sunday, between 6pm and 7pm on Monday and at 6pm and 6.30pm on Tuesday.

Sunday, 17 July

6:00 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	108.10	59.76	55.00
Demand (MW)	1,612	1,643	1,556
Available capacity (MW)	2,302	2,162	2,160
6:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	271.28	52.04	89.25
Demand (MW)	1,816	1,771	1,701
Available capacity (MW)	2,305	2,162	2,160
7:00 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	134.52	52.96	88.18
Demand (MW)	1,909	1,845	1,833
Available capacity (MW)	2,307	2,182	2,160

Conditions at the time saw demand close to forecast, with prices aligned with Victoria and reflecting conditions in New South Wales. Delays in the return of transmission elements in Victoria, following a planned network outage, limited flows across the Victoria to South Australia interconnector to 250MW, around 150MW less than that forecast. The Murraylink interconnector was unconstrained during this period. At 6.12pm a rebid by AGL saw 60MW of capacity at Hallet shifted from prices around $9,400/MWh to zero resulting in the unit being committed. The reason given was "Predispatch forecast price increase: 5 min". There was no other significant rebidding.

Monday, 18 July

6:00 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	112.87	50.40	96.04
Demand (MW)	1,838	1,900	1,960
Available capacity (MW)	2,630	2,697	2,690
6:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	148.87	79.80	291.80
Demand (MW)	2,035	2,039	2,076
Available capacity (MW)	2,641	2,647	2,690
7:00 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	119.00	55.10	110.44
Demand (MW)	2,146	2,073	2,129
Available capacity (MW)	2,644	2,647	2,690

Conditions at the time saw demand close to forecast with prices aligned with Victoria and reflecting conditions in New South Wales and Queensland.

Over two rebids at 5.30pm and 6pm, TRU Energy rebid up to 130 MW of capacity at Torrens Island priced at $55/MWh and below to $149/MWh. The rebid reason given was "market conditions- gen response to PD conditions". AGL committed 60 MW of capacity at Hallett in response to the changing prices, through rebids that shifted 60 MW of capacity priced at $9,444/MWh to zero at around 6pm. The rebid reason given were "predispatch: forecast price increase", and "capacity adjustment due to ambient temperature". There was no other significant rebidding.

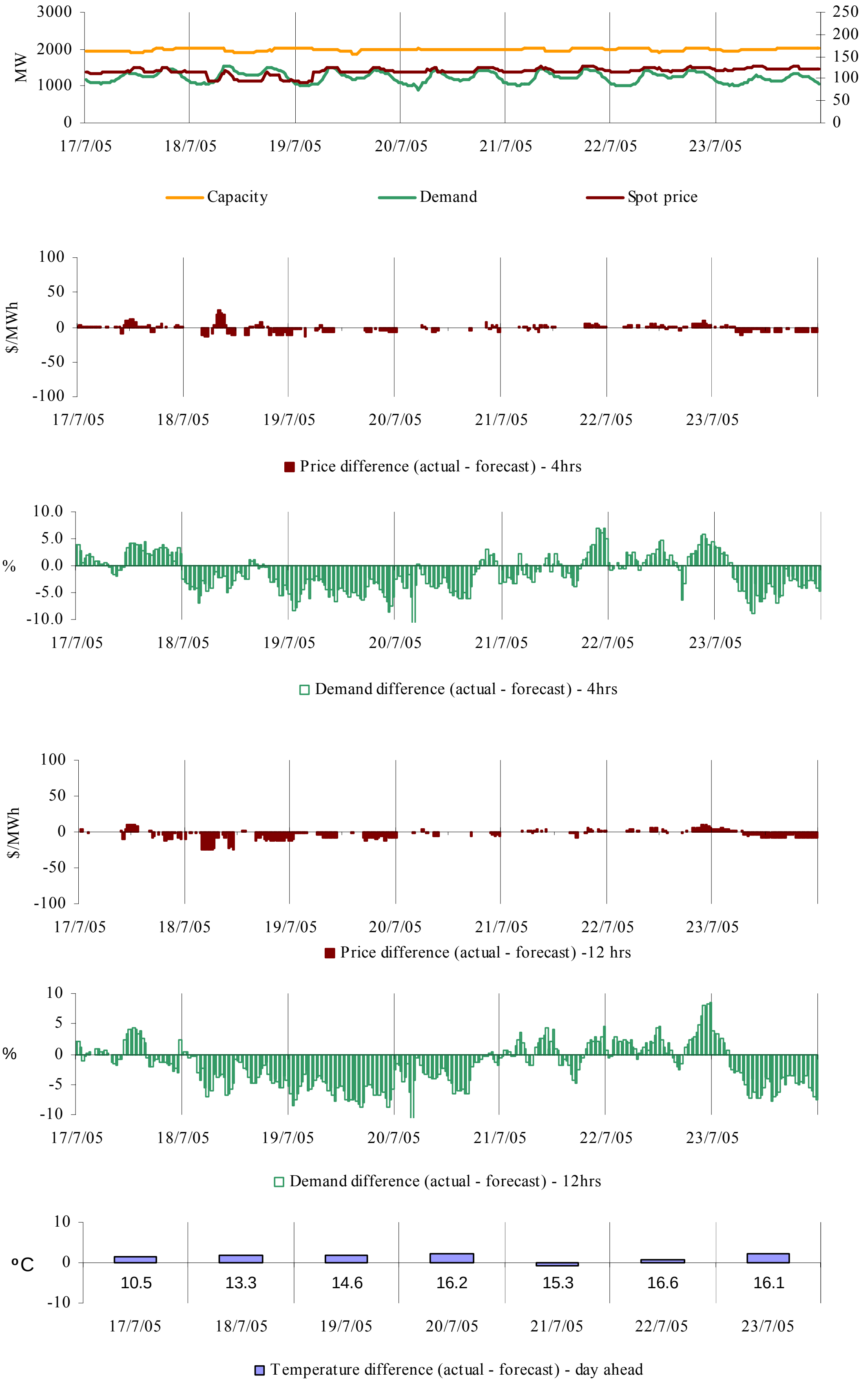
Tuesday, 19 July

6:00 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	125.94	85.38	96.80
Demand (MW)	1,865	1,982	2,008
Available capacity (MW)	2,793	2,759	2,760
6:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	112.47	299.10	149.10
Demand (MW)	2,053	2,086	2,110
Available capacity (MW)	2,799	2,759	2,760

Conditions at the time saw demand and price close to forecast, with prices aligned across the mainland regions.

At 5.15pm, for the 6pm trading interval, TRU Energy rebid 240 MW of capacity at Torrens Island priced less than $100/MWh to greater than $149/MWh. The rebid reason given was “market conditions- gen response to PD conditions”. This bid was largely reversed by a rebid first used in the 6pm despatch interval. AGL committed 60 MW of capacity at Hallett in response to the changing prices, through rebids that shifted 60 MW of capacity priced at $9,444/MWh to zero at around 6pm. The rebid reasons given were “predispatch: forecast price increase”. There was no other significant rebidding.

Figures 45-50: Tasmania actual spot price, demand and forecast differences



There were no occasions in Tasmania where the spot price was greater than three times the weekly average price of $117/MWh.

Figure 51: Queensland closing bid prices, despatched generation and spot price

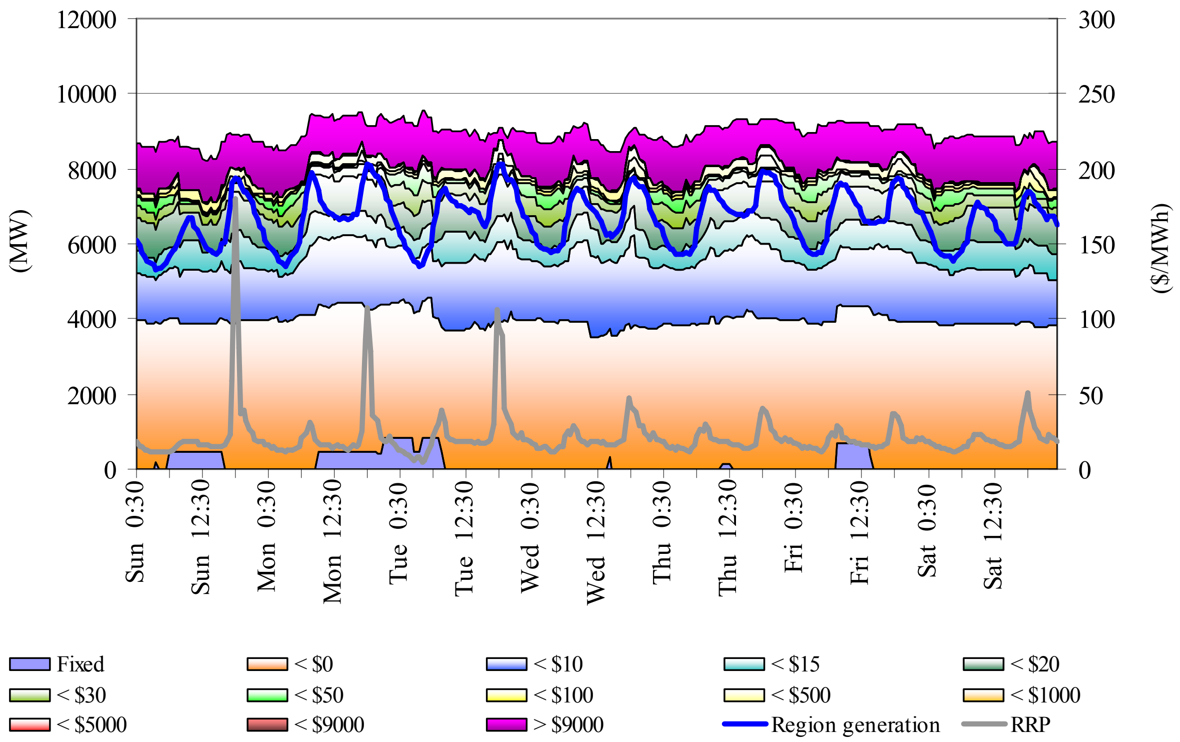


Figure 52: New South Wales closing bid prices, despatched generation and spot price

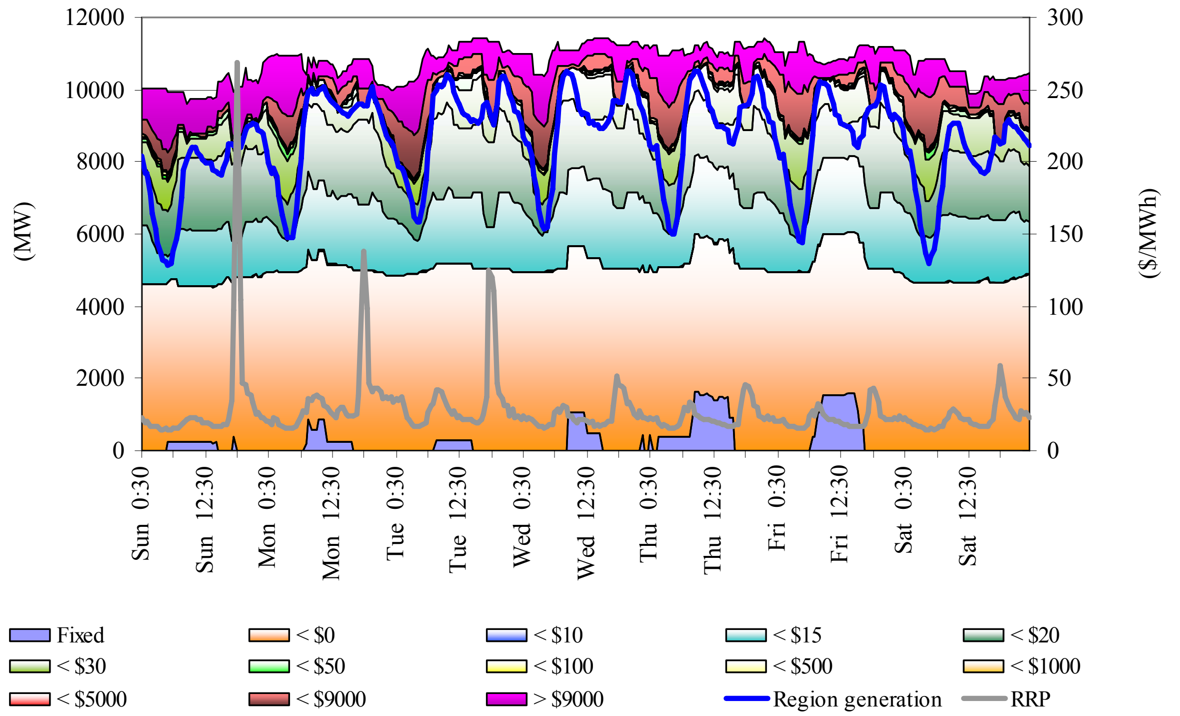


Figure 53: Victoria closing bid prices, despatched generation and spot price

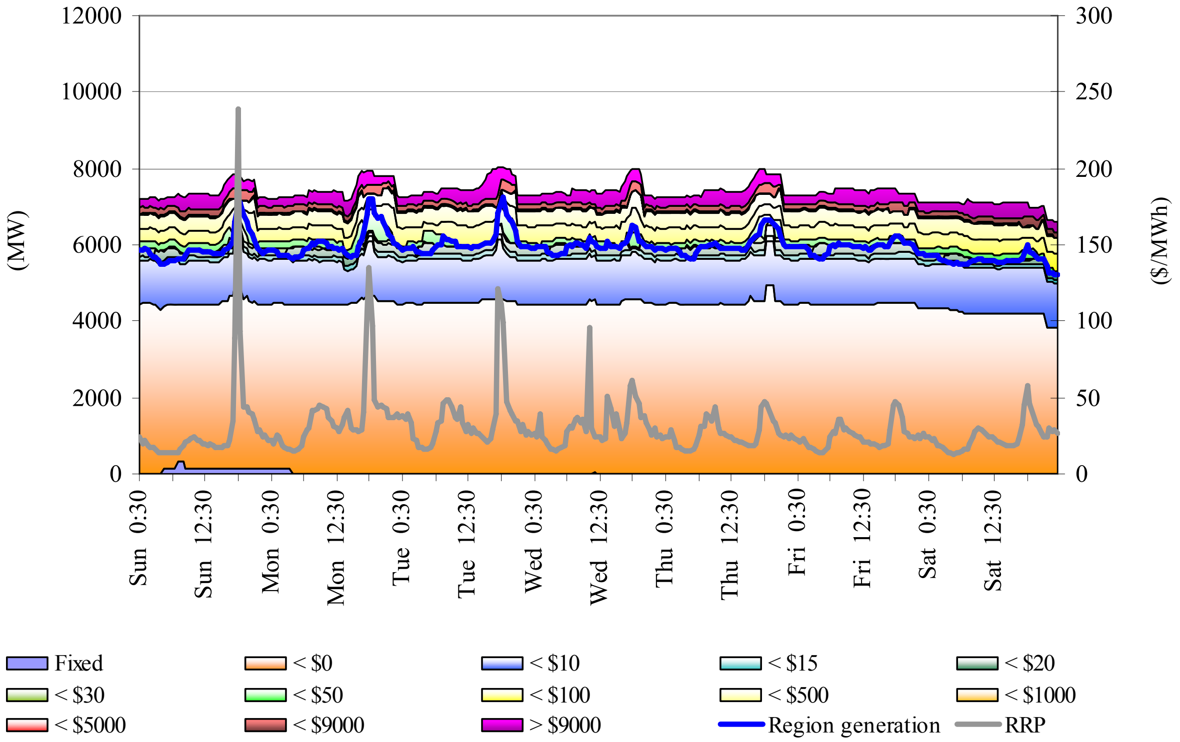


Figure 54: South Australia closing bid prices, despatched generation and spot price

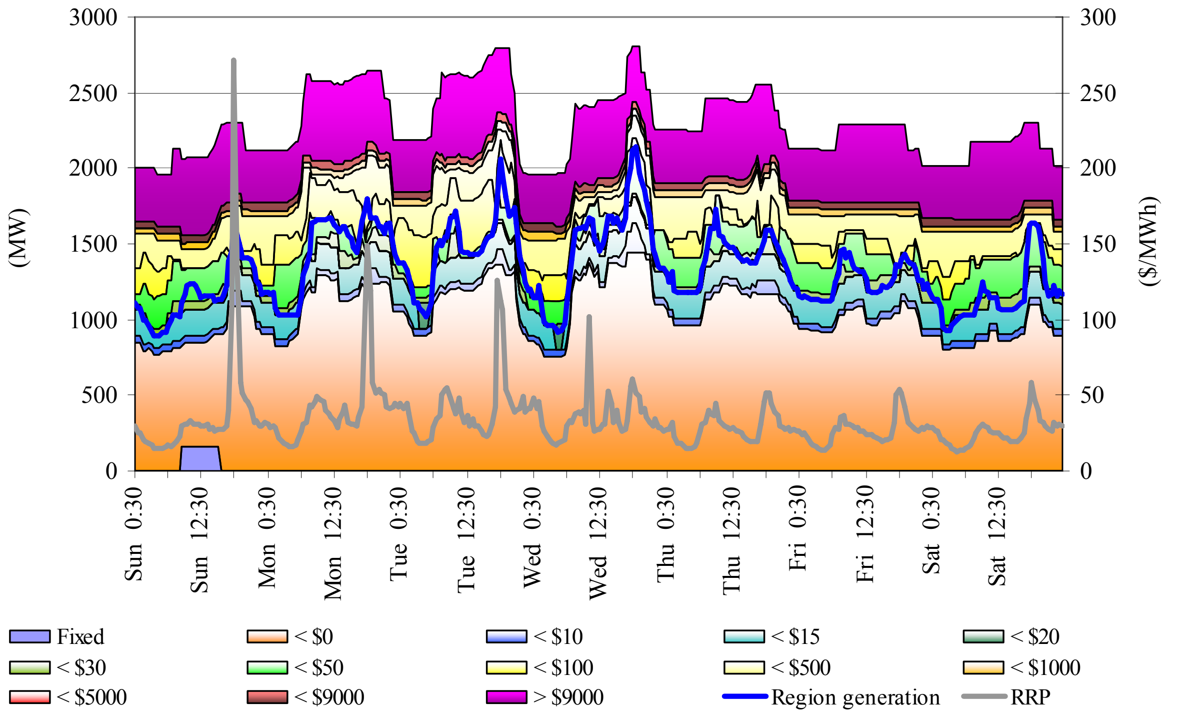
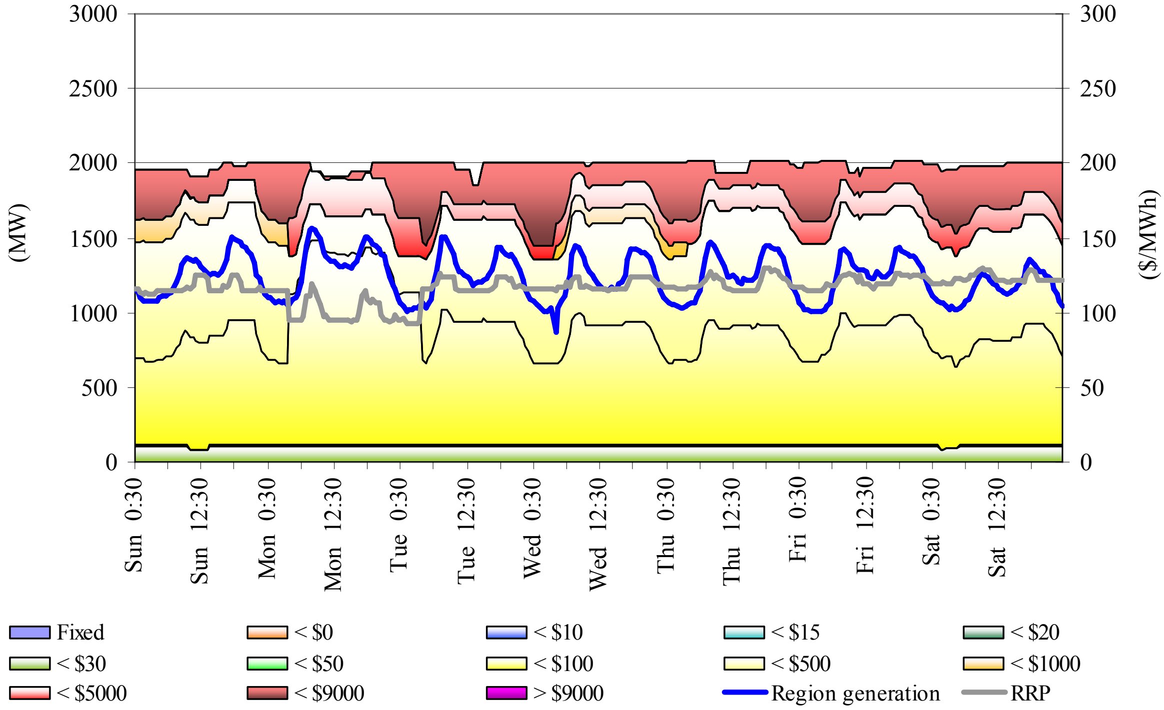


Figure 55: Tasmania closing bid prices, despatched generation and spot price



Ancillary service market

The total cost of ancillary services for the week was $440,000 or 0.3 per cent of the total turnover in the energy market. A planned transmission outage in Victoria on Sunday, and for a number of short periods throughout the week, resulted in an increased requirement for lower contingency services.

The cost for ancillary services in Tasmania totalled $128,000 or 0.5 per cent of the energy market turnover for that region. Figure 56 summarises the volume weighted average prices and costs for the eight frequency control ancillary services across the interconnected regions. Figure 57 summarises the volume weighted average prices and costs for the eight frequency control ancillary services for Tasmania.

Figure 56: volume weighted average frequency control ancillary service prices

	Raise 6 sec	Raise 60 sec	Raise 5 min	Raise reg	Lower 6 sec	Lower 60 sec	Lower 5 min	Lower reg
Last week ($)	1.29	0.58	0.87	1.44	0.17	1.56	2.57	1.79
Previous week($)	1.36	0.51	0.85	0.96	0.18	1.45	2.26	1.60
Last Quarter($)	2.43	0.81	0.99	1.07	0.23	0.96	2.96	1.51
Market Cost ($1000s)	$64	$29	$58	$34	$1	$17	$64	$42
% of energy market	0.03%	0.01%	0.03%	0.02%	0.00%	0.01%	0.03%	0.02%

Figure 57: volume weighted average frequency control ancillary service price for Tasmania

	Raise 6 sec	Raise 60 sec	Raise 5 min	Raise reg	Lower 6 sec	Lower 60 sec	Lower 5 min	Lower reg
Last week ($)	1.48	1.05	1.06	1.36	1.06	1.05	1.05	1.05
Previous week($)	2.75	1.05	1.06	1.28	1.06	1.05	1.05	1.05
Market Cost ($1000s)	$15	$11	$12	$11	$13	$31	$26	$9
% of energy market	0.06%	0.04%	0.05%	0.05%	0.06%	0.13%	0.11%	0.04%

Figure 58 shows the daily breakdown of cost for each frequency control ancillary service.

Figure 58: daily frequency control ancillary service costs

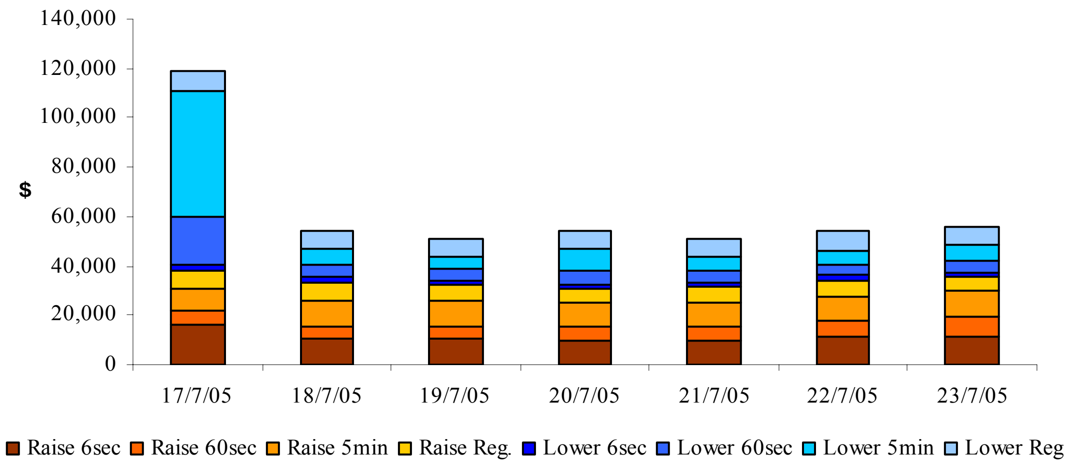
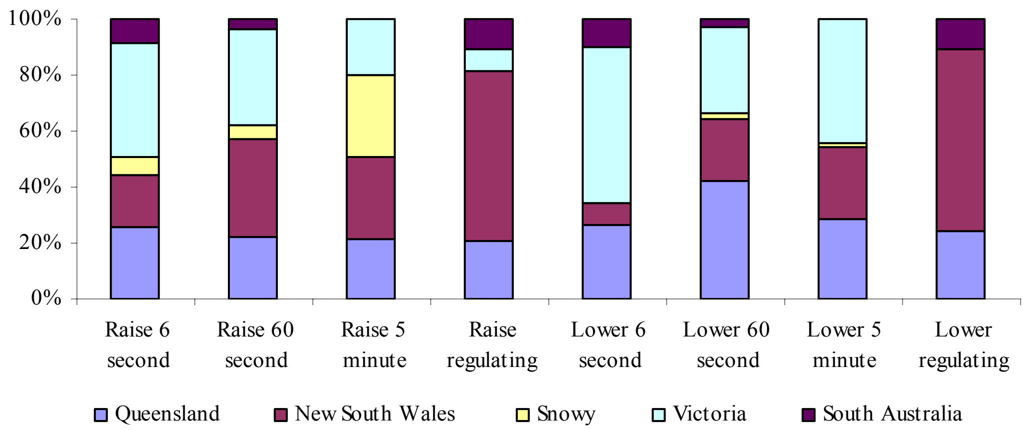


Figure 59 shows the regional weekly participation in each of the ancillary service markets on the mainland.

Figure 59: regional participation in ancillary services



Figures 60 and 61 show 30-minute prices for each of the ancillary services.

Figure 60: prices for raise services

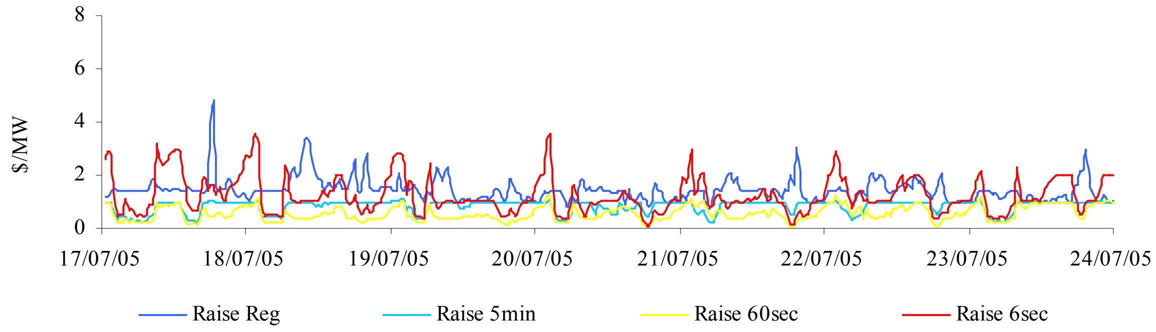


Figure 60A: prices for raise services - Tasmania

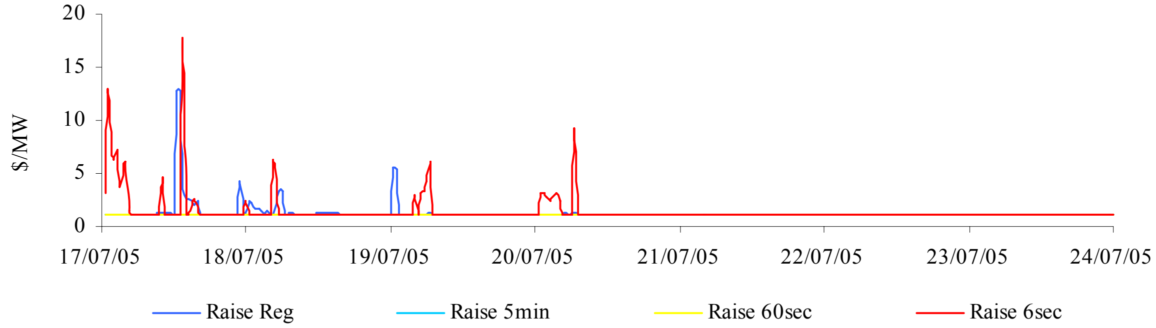


Figure 61: prices for lower services

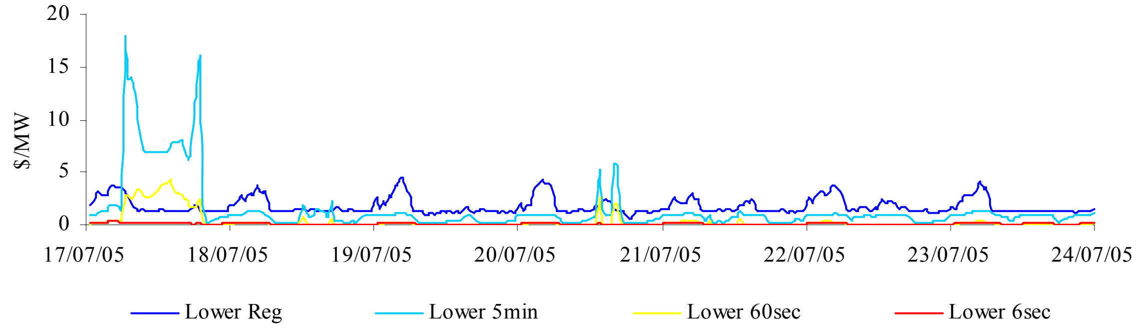
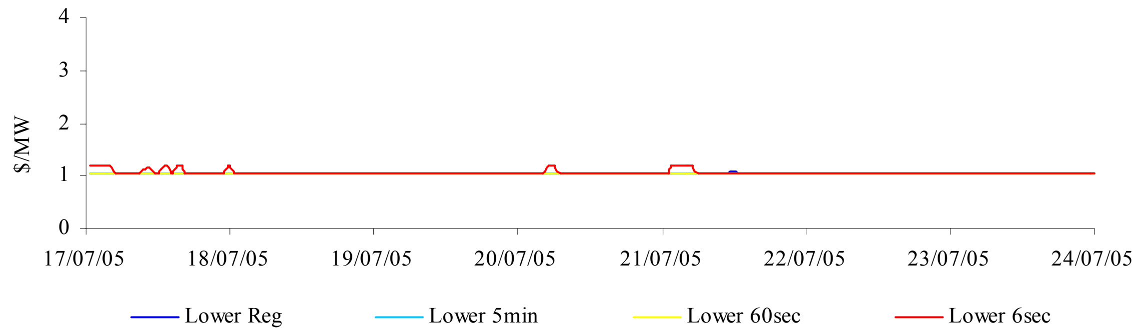


Figure 61A: prices for lower services - Tasmania



Figures 62 and 63 present for both raise and lower services the requirement for each service over the week.

Figure 62: raise requirements

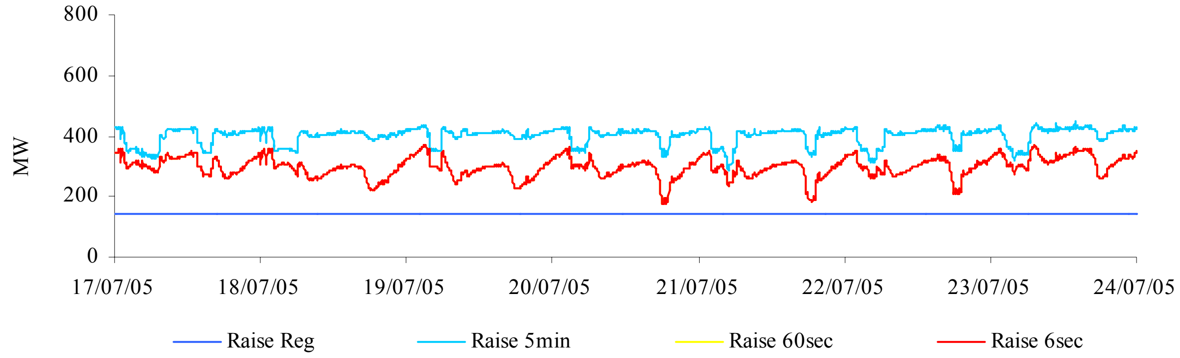


Figure 62A: raise requirements - Tasmania

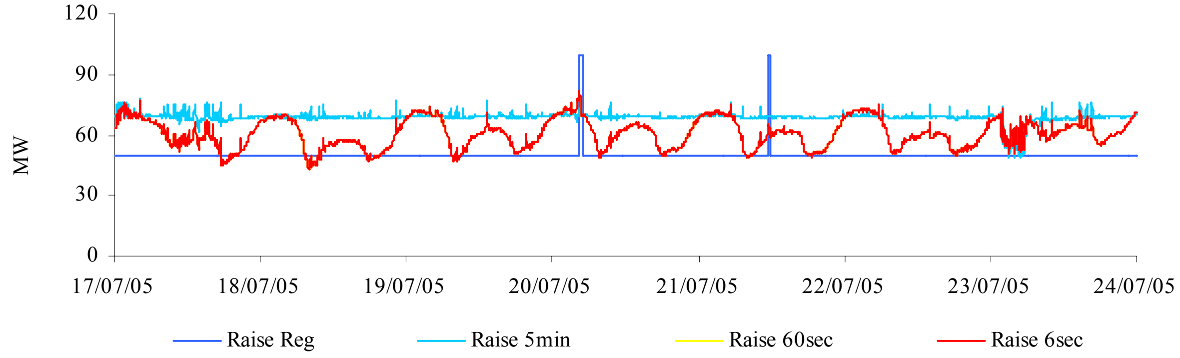


Figure 63: lower requirements

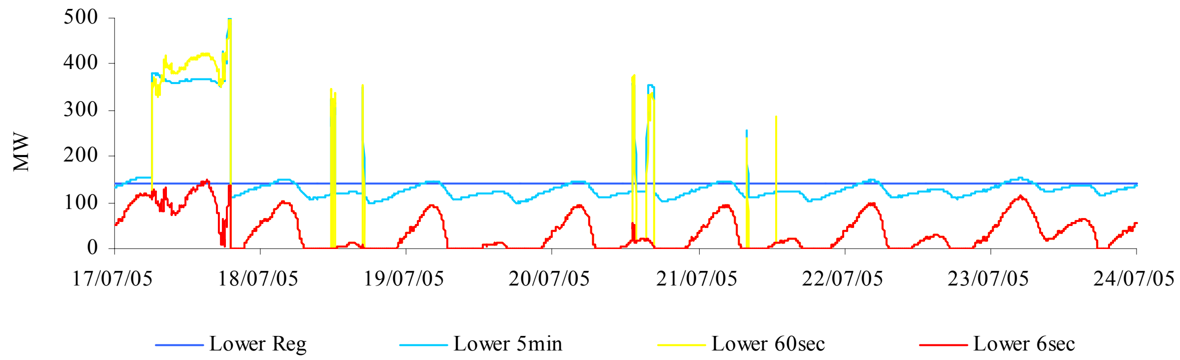
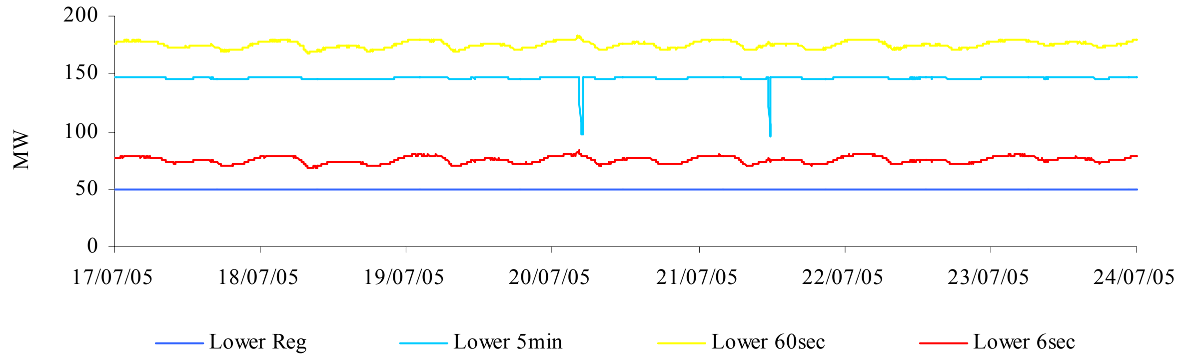


Figure 63A: lower requirements - Tasmania



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