Market analysis

15–21 JANUARY 2006

Extreme temperatures in South Australia and Victoria late in the week resulted in average spot prices rising to $198/MWh and $115/MWh respectively. A new record demand occurred in South Australia on Thursday and again on Friday reaching almost 2880 MW. This represented an increase of around 40 MW on the previous high set in February 2001. Spot prices peaked at $4900/MWh on Thursday. Demand in Victoria exceeded 8550 MW on Friday, just short of the previous record set in December 2003.

Average spot prices in other regions were similar to the previous week averaging $20/MWh in Queensland, $24/MWh in New South Wales and $35/MWh in Tasmania.

Turnover in the energy market for the mainland was $243 million. The total cost of ancillary services for the week was just over $200 000, or less than 0.1 per cent of turnover. Turnover in Tasmania for the week was $6.3 million with the cost of ancillary services totaling $125 000 or 2 per cent of turnover.

Significant variations between actual prices and those forecast 4 and 12 hours ahead occurred in 136, or around 40 per cent of all trading intervals. Demand forecasts produced 4 and 12 hours ahead varied from actual by more than 5 per cent in almost a third of all trading intervals across the market. These variations were most frequent in South Australia occurring in around two thirds of all trading intervals. In contrast demand forecasts produced 4 and 12 hours ahead in Queensland were within 5 per cent of the actual in all but three trading intervals.

Energy prices

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

Figure 1: national demand and spot prices

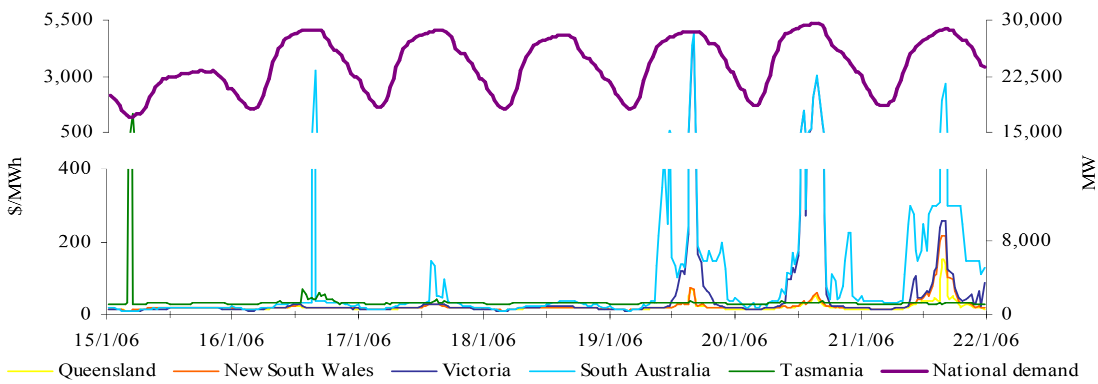


Figure 2: volume weighted average spot price for energy market ($/MWh)

	QLD	NSW	VIC	SA	TAS
Last week	20	24	115	198	35
Previous week	21	26	23	38	32
Same quarter last year	25	35	22	31	-
Financial year to date	31	47	33	46	78
% change from previous week*	▼5%	▼8%	▲389%	▲419%	▲10%
% change from same quarter last year**	▼19%	▼33%	▲419%	▲532%	-
% change from year to date***	▼15%	▼20%	▲4%	▲7%	-

*The percentage change between last week's average spot price and the average price for the previous week.
**The percentage change between last week's average spot price and the average price for the same quarter last year.
***The percentage change between the average spot price for the current financial year to date and the average spot price over the similar period for the previous financial year.

Figure 3: volatility index during peak periods

	QLD	NSW	VIC	SA	TAS
Last week	0.51	0.51	4.64	5.59	0.08
Previous week	1.04	1.28	1.07	0.90	0.12
Same quarter last year	0.73	0.74	0.78	0.70	-

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

Figure 4: Queensland

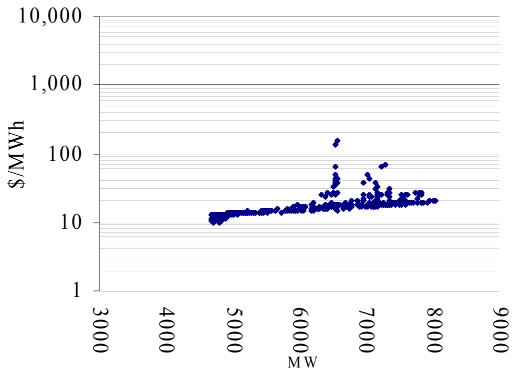


Figure 5: New South Wales

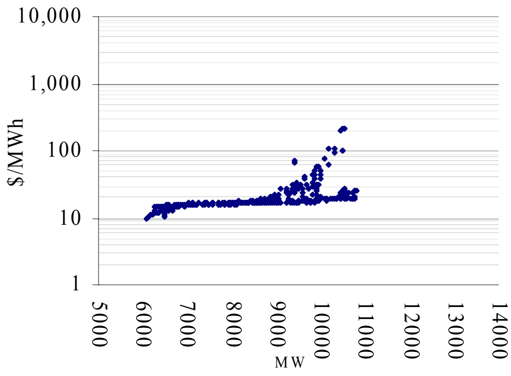


Figure 6: Victoria

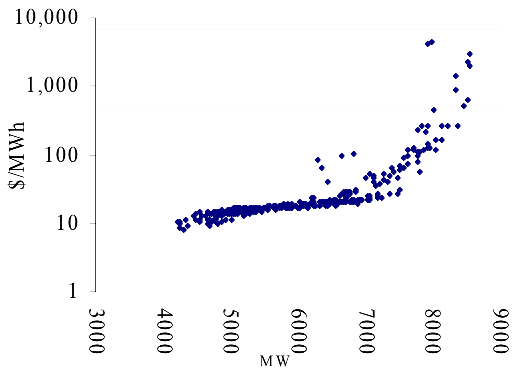


Figure 7: South Australia

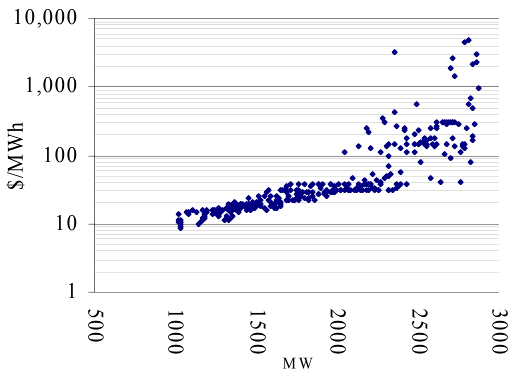
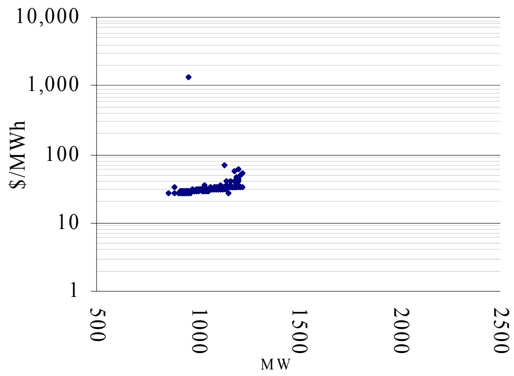


Figure 8: Tasmania



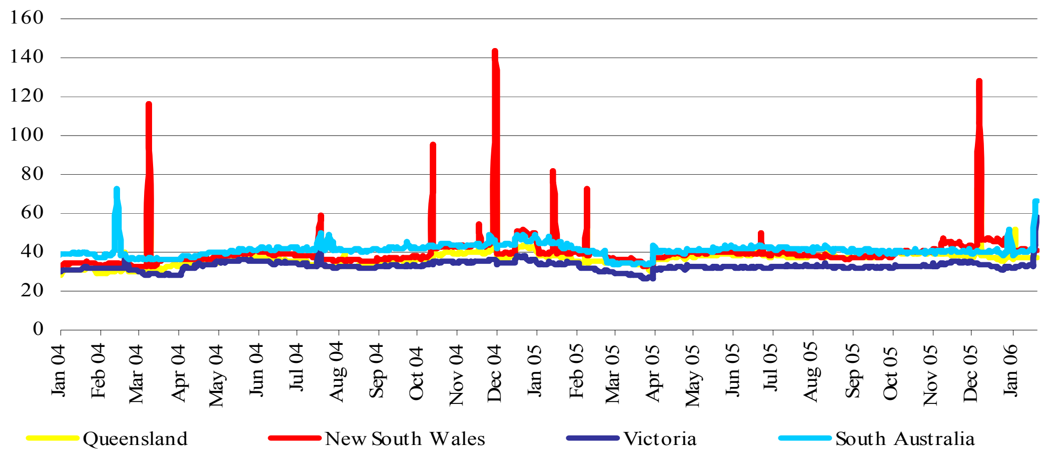
Maximum spot prices of $152/MWh in Queensland and $217/MWh in New South Wales occurred at 3.30pm on Saturday. Maximum spot prices of $4519/MWh in Victoria and $4900/MWh in South Australia occurred at 4 pm on Thursday. In Tasmania, the highest spot price for the week of $1357/MWh was recorded at 4.30am on Sunday following one 5-minute dispatch price of $8000/MWh. This price resulted from a trade-off between energy and ancillary service offers.

Figure 9 sets out the d-cyphaTrade wholesale electricity price index (WEPI) for each region throughout the week excluding Tasmania. The WEPI reflects changes in exchange traded contracts and spot prices, load conditions and the proportion of total load contracted at any one time. Figure 10 sets out the WEPI since 1 January 2004.

Figure 9: d-cyphaTrade WEPI for the week

	Monday	Tuesday	Wednesday	Thursday	Friday
Queensland	37.11	37.21	36.99	37.21	37.01
New South Wales	41.22	41.30	40.82	40.86	41.12
Victoria	33.24	33.04	33.05	43.20	58.21
South Australia	41.46	41.06	40.49	65.17	66.22

Figure 10: d-cyphaTrade WEPI



Reserve

Despite the high demand in Victoria and South Australia there were no low reserve conditions forecast for the week. Directions were issued to a MNSP each day throughout the working week to manage local network issues in northern New South Wales. 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

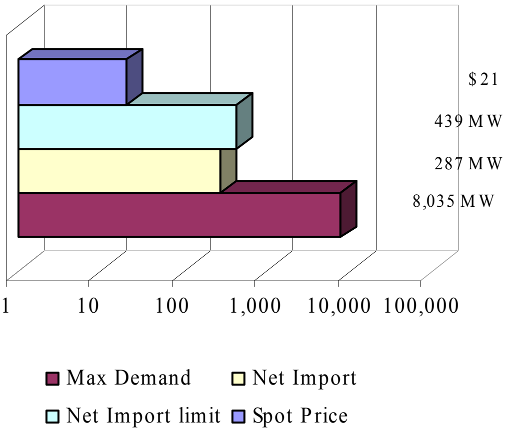


Figure 12: New South Wales

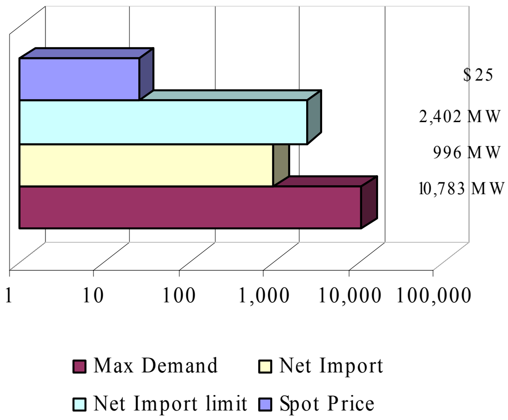


Figure 13: Victoria

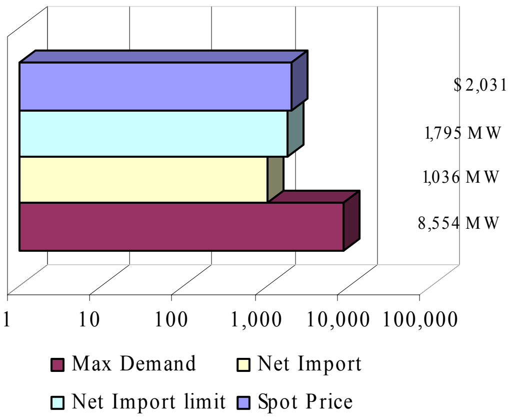
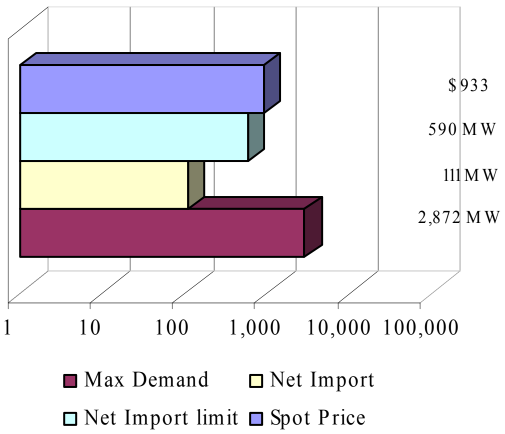


Figure 14: South Australia



In Tasmania, demand reached a maximum of 1222 MW at 8am on Wednesday morning. The spot price at that time was $34/MWh.

Price variations

There were 136 trading intervals where actual prices significantly varied from forecasts made 4 and 12 hours ahead of dispatch. Figures 15 to 19 show the difference in actual and forecast price versus the difference in actual and forecast demand. The figures highlight the correlation between price variation and demand forecast error. The information is presented in terms of the percentage difference from actual. Price differences beyond 100 per cent have been capped.

Figure 15: Queensland

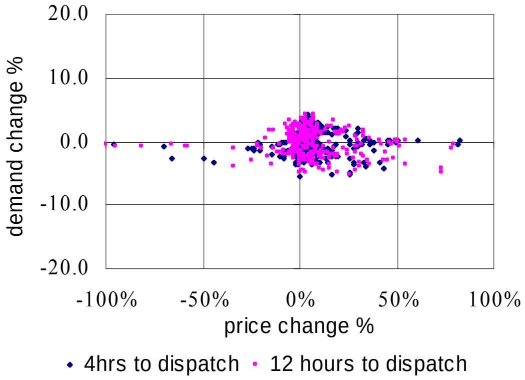


Figure 16: New South Wales

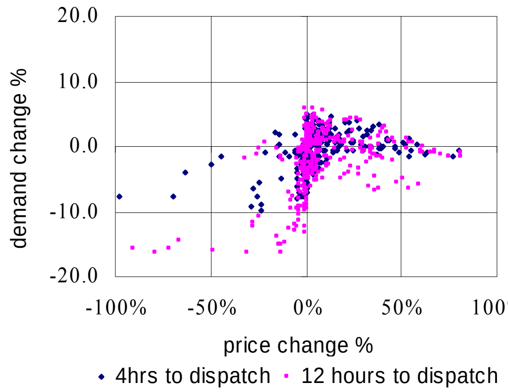


Figure 17: Victoria

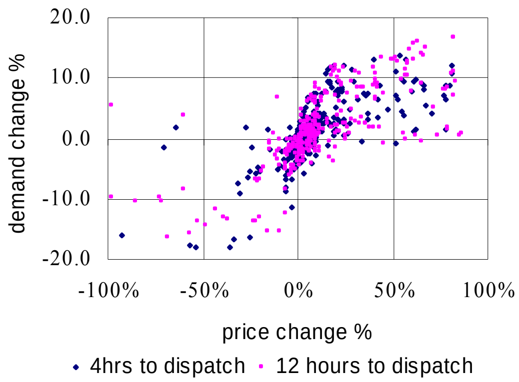


Figure 18: South Australia

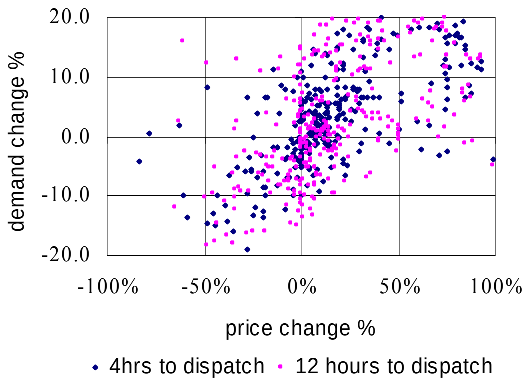


Figure 19: Tasmania

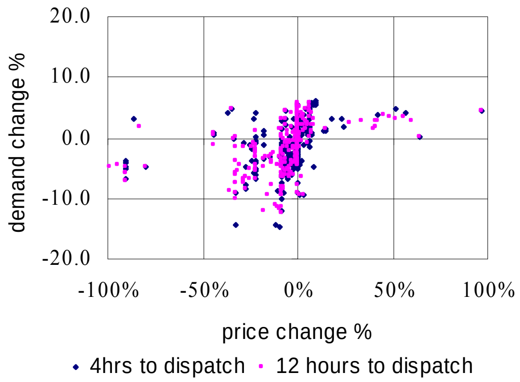
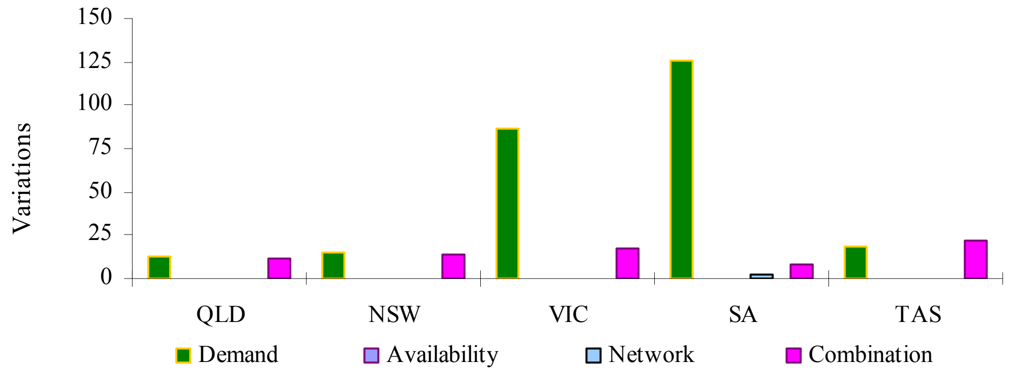


Figure 20 summarises the number and most probable reason for variations between forecast and actual prices.

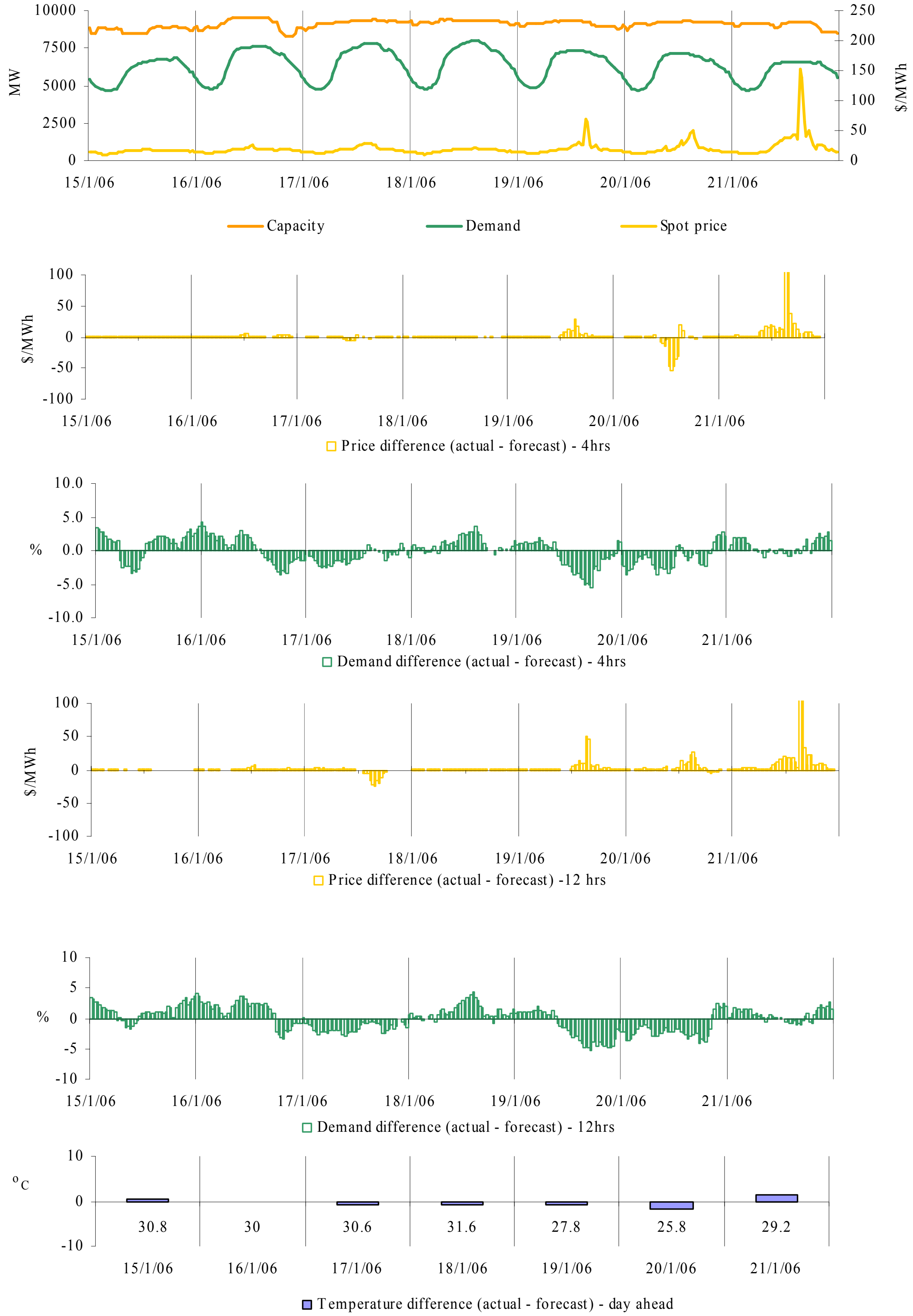
Figure 20: reasons for variations between forecast and actual prices



Price and demand

Figures 21 - 50 set out details of spot prices and demand on a regional basis. They include the actual spot price, actual demand outcomes and variation from forecasts made 4 and 12 hours ahead of dispatch 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 dispatched in a region are overlaid.

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



There were 5 occasions in Queensland where the spot price was greater than three times the weekly average price of $20/MWh. These occurred on Thursday and Saturday afternoon.

Thursday, 19 January

3:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	67.90	38.50	18.24
Demand (MW)	7280	7589	7580
Available capacity (MW)	9220	9613	9637
4:00 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	64.25	48.00	17.37
Demand (MW)	7222	7595	7570
Available capacity (MW)	9239	9613	9637

Conditions at the time saw demand around 300 MW lower than forecast with available capacity almost 400 MW lower than expected.

Steam feed pump problems on Unit 4 at Callide C had seen the unit operating at a reduced output of 150 MW since the previous day. The unit was forecast to return to 415 MW from 1pm. Rebids from around 11.20am saw the reduction in output extended for the remainder of the day. The rebid reason given was “SFP repairs” The unit returned to full capacity the following day.

From around 2pm, a further 11 5MW reduction in available capacity occurred across Gladstone and Millmerran power stations. The rebid reasons given by Enertrade were “plant problem::change availability” and “sootblow::change MW distrib”. The rebid reasons given by Millmerran were “dust emission limits”.

At 3.08pm, effective immediately, Stanwell Corporation rebid 180 MW of capacity at Stanwell power station from prices below $20/MWh to more than $90/MWh. The rebid reason given was “RRP grt pre disp, bandshift up”.

There was no other significant rebidding.

Saturday, 21 January

3:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	151.66	27.00	30.70
Demand (MW)	6574	6570	6599
Available capacity (MW)	9208	9208	9208
4:00 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	137.05	25.20	29.81
Demand (MW)	6541	6565	6604
Available capacity (MW)	9208	9208	9208
4:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	63.81	25.15	30.70
Demand (MW)	6533	6526	6592
Available capacity (MW)	9211	9208	9208

Conditions at the time saw demand and available capacity aligned with the forecast. Flows south into New South Wales were constrained at their limits for most of the period.

Just prior to 3pm, CS Energy rebid 60 MW of capacity at Callide B and Swanbank B and E from prices of less than $50/MWh to prices ranging from $90/MWh to more than $4000/MWh. The reason given was “response to interconnector constraint”.

Between 3pm and 4pm Tarong rebid a total of 70 MW of capacity from the Tarong Power Station from prices below $15/MWh to prices of around $170/MWh and $290/MWh. The rebid reason was “change in PD: optimise portfolio”. This capacity was returned to prices below $15/MWh at 4.16pm.

There was no other significant rebidding.

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

There were 10 occasions in New South Wales where the spot price was greater than three times the weekly average price of $24/MWh. These occurred on Thursday and Saturday afternoon.

Thursday, 19 January

3:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	72.04	38.75	17.73
Demand (MW)	9416	9421	9563
Available capacity (MW)	10 527	10 707	10 889

Conditions at the time saw demand close to forecast and available capacity down slightly. Prices in New South Wales were aligned with Queensland but separated from the much higher prices in the southern regions. Flows from Snowy into New South Wales were counter- price during this period.

There was no significant rebidding.

Saturday, 21 January

1:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	76.79	39.25	30.41
Demand (MW)	10 102	10 184	10 200
Available capacity (MW)	10 575	11 177	11 173
2:00 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	104.89	39.66	30.55
Demand (MW)	10 168	10 291	10 288
Available capacity (MW)	10 575	11 177	11 173
2:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	110.63	40.84	35.79
Demand (MW)	10 319	10 403	10 415
Available capacity (MW)	10 559	11 477	11 473
3:00 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	204.30	39.58	39.21
Demand (MW)	10 439	10 514	10 522
Available capacity (MW)	10 589	11 477	11 473
3:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	216.81	50.00	39.77
Demand (MW)	10 495	10 657	10 652
Available capacity (MW)	10 726	11 475	11 478
4:00 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	214.89	100.00	39.97
Demand (MW)	10 544	10 705	10 700
Available capacity (MW)	11 119	11 475	11 478
4:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	103.02	86.81	39.53
Demand (MW)	10 511	10 590	10 607
Available capacity (MW)	11 169	11 475	11 478

5:00 pm	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	100.00	86.30	39.32
Demand (MW)	10 472	10 529	10 529
Available capacity (MW)	11 122	11 475	11 478
5:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	95.98	42.83	30.73
Demand (MW)	10 306	10 362	10 361
Available capacity (MW)	11 002	11 475	11 478

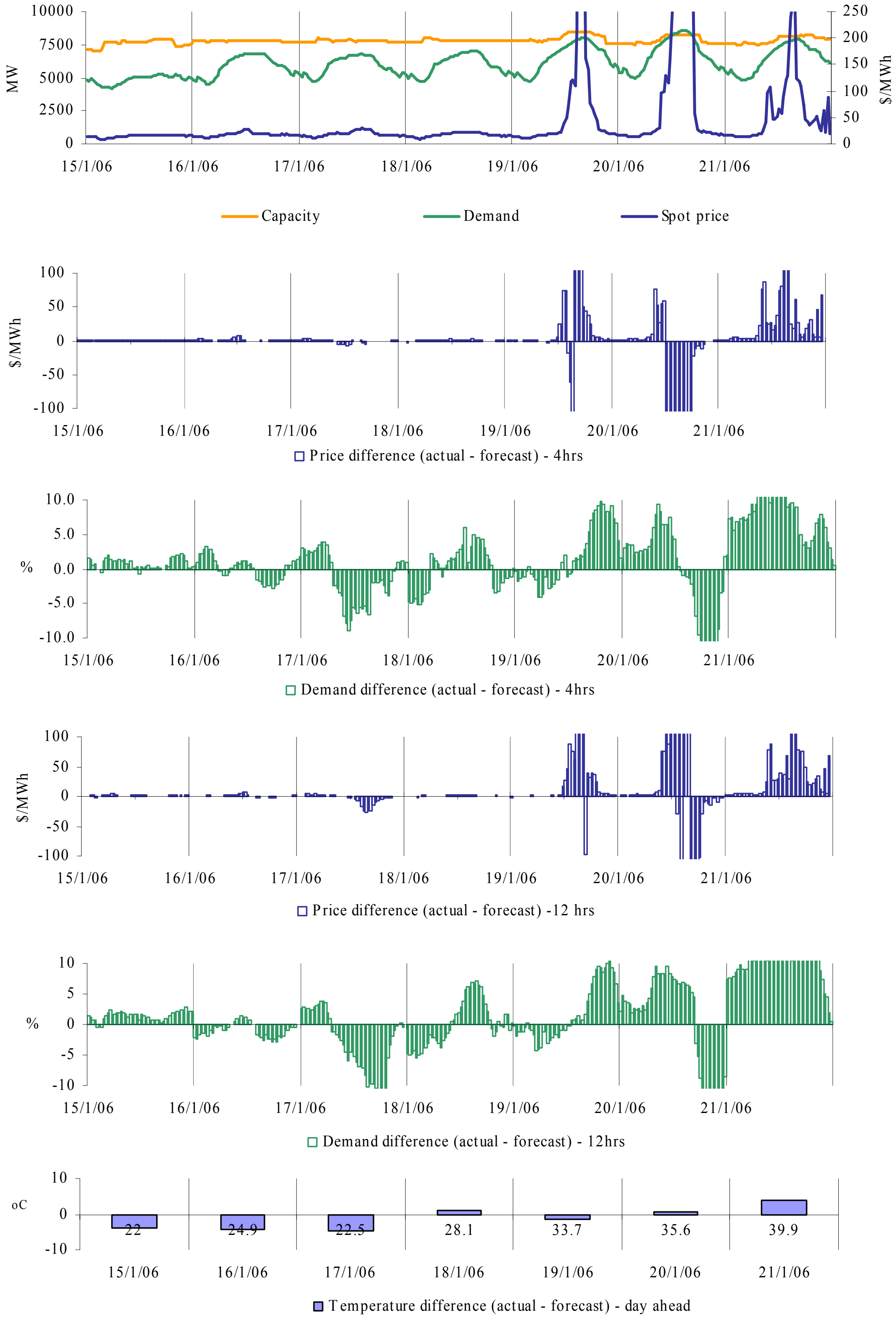
Conditions at the time saw demand and available capacity lower than forecast. Available capacity was up to 800 MW lower than anticipated, primarily as a result of delays in the return to service of a Vales Point unit and problems at Eraring.

Delta Electricity's Vales Point Unit 6 had been out of service since the previous Wednesday and was schedule to return at 9am. A number of delays saw the unit return around 2pm reaching 330 MW, or half of its capacity, by 8pm.

Eraring Unit 1, which had 380 MW available, was scheduled to return an additional 300 MW to service at approximately 2pm. Rebids at 1.56pm and 2pm delayed the return of that capacity. The reasons given were "P: Air heater still out of service @13:55" and "P: capacity update @14:01" The capacity was returned to service at 4pm.

There was no other significant rebidding.

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



There were 10 occasions in Victoria where the spot price was greater than three times the weekly average price of $115/MWh. These occurred on Thursday and Friday afternoon.

Thursday, 19 January

3:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	4063.65	4251.39	595.73
Demand (MW)	7927	7782	7885
Available capacity (MW)	8460	8457	8121
4:00 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	4519.47	4250.49	595.74
Demand (MW)	7984	7764	7924
Available capacity (MW)	8498	8452	8121
4:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	456.90	266.92	262.06
Demand (MW)	8026	7735	7892
Available capacity (MW)	8492	8442	8121

Conditions at the time saw demand peak at just over 8000 MW. At the same time demand in South Australia was at record levels of more than 2800 MW with prices aligned across the two regions.

A network limitation within the Snowy region between Murray and Tumut, was at times affecting the limits on both the Victoria to Snowy and Snowy to New South Wales interconnectors. Generation at Murray, on the Victorian side of this constraint, was not dispatched with all capacity priced above $7000/MWh.

At 1.40pm NEMMCO invoked constraints, to manage the accumulation of negative settlements across the Victoria to Snowy interconnector.

There was no significant rebidding.

Friday, 20 January

1:00 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	1471.86	4450.74	265.42
Demand (MW)	8344	8317	7744
Available capacity (MW)	8280	8229	8496
2:00 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	520.56	4450.73	356.83
Demand (MW)	8453	8541	7881
Available capacity (MW)	8219	8232	8496
2:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	656.18	4450.74	1780.42
Demand (MW)	8535	8621	7951
Available capacity (MW)	8234	8245	8482

3:00 pm	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	2031.36	4821.87	1780.42
Demand (MW)	8554	8651	7980
Available capacity (MW)	8205	8268	8482
3:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	2995.17	5109.80	1780.42
Demand (MW)	8553	8673	8000
Available capacity (MW)	8276	8289	8482
4:00 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	2280.99	4747.04	1780.42
Demand (MW)	8510	8699	7990
Available capacity (MW)	8236	8289	8482
4:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	902.69	4794.74	1790.42
Demand (MW)	8358	8690	7915
Available capacity (MW)	8204	8284	8367

Conditions at the time saw demand just short of the record at 8554 MW, almost 600 MW higher than that forecast 12 hours prior to dispatch. Available capacity during this time was up to 300 MW lower than forecast.

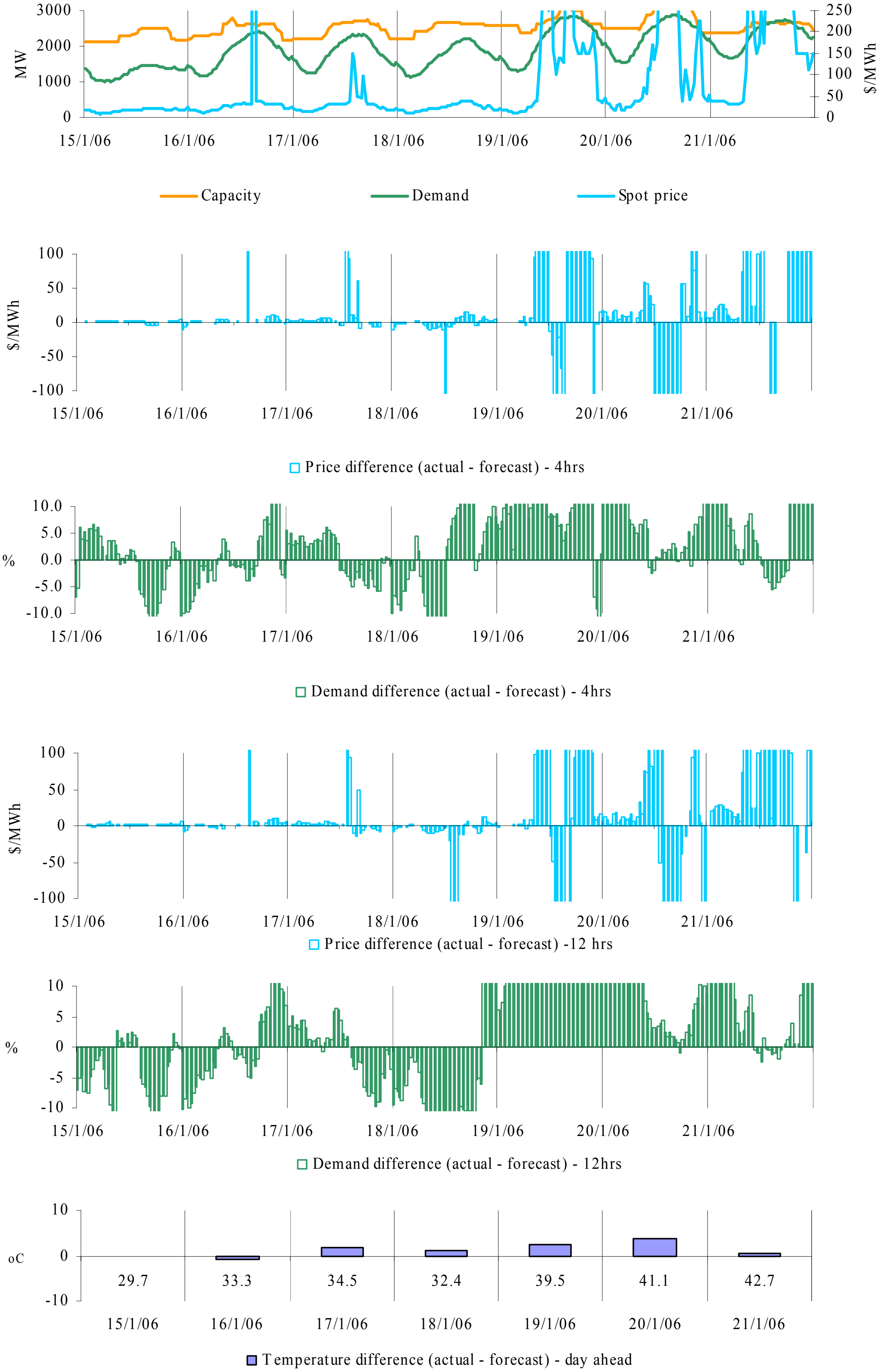
International Power shifted 160 MW of capacity at Hazelwood from prices over $1700/MWh at 12.15pm. Of this, 100 MW was re-priced below $260/MWh and the remaining 60 MW at approximately $90/MWh. The rebid reason given was “change in price forecast”. At 12.40pm Hazelwood’s available capacity was increased by 80 MW, however, at 1.30pm this was reduced by 25 MW. The rebid reasons given were “Draft plant limit” and “fuel limitations” respectively.

From midday, Ecogen shifted as much as 230 MW of capacity across Jeeralang A and B from prices above $4000/MWh to prices of $145/MWh and $1/MWh. The rebid reasons given included “Adj to unit commitment due to PD conditions” and “Adj to unit commitment due to plant limitations”.

LYMMCO shifted 155 MW of capacity at Loy Yang A from below $15/MWh to over $9500/MWh at 1pm. The rebid reason given was “material change in PD”. At 2.30pm, 420 MW was rebid from over $9500/MWh to approximately -$950/MWh. The rebid reason given was “potential bushfire risk management”.

There was no other significant rebidding.

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



There were 10 occasions in South Australia where the spot price was greater than three times the weekly average price of $198/MWh. These occurred on Monday, Thursday, Friday and Saturday.

Monday, 16 January

3:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	3279.33	38.00	35.85
Demand (MW)	2360	2454	2474
Available capacity (MW)	2609	2614	2781

Conditions at the time saw demand and available capacity close to forecast. Five-minute prices of $4900/MWh were published for the 3.15pm to 3.30pm dispatch intervals. This followed the introduction of a constraint by NEMMCO that reduced the limit on the MurrayLink interconnector from 216 MW to 40 MW at 3.15pm. The limit returned to around 210 MW from 3.35pm.

During the period, Origin Energy reduced the availability of Ladbroke Unit 1 from 43MW to zero. Rebid reason given was “Unit failed to start”. Cummins Engine Company shifted 20 MW of capacity at Angaston from prices above $5000/MWh to $10/MWh. The rebid reason given as “optimise AS and energy::decrease energy band”.

Thursday, 19 January

3:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	4411.97	4900.00	4900.00
Demand (MW)	2788	2684	2469
Available capacity (MW)	3033	2808	2745
4:00 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	4900.00	4900.00	2037.50
Demand (MW)	2814	2664	2438
Available capacity (MW)	3037	2808	2745

Spot prices during this period peaked at $4900/MWh and were close to forecast. Demand peaked above 2800 MW setting a new record, surpassing the old record by 10 MW. Actual demand was 400 MW higher than forecast 12 hours ahead and around 100 MW higher than the four hour ahead forecast. The temperature reached 40 degrees, around 3 degrees higher than the day ahead forecast. Available capacity was around 300 MW higher than forecast.

At 12.08pm, International Power increased the availability of Pelican Point by 222 MW, with 170 MW of this capacity priced at less than zero. The rebid reason given was “Change in price forecasts”. The increased availability was extended at 1.51pm until 6.30pm.

At 1.55pm, Cummins Engine Company shifted 40 MW of capacity at Angaston from around $5000/MWh to $11/MWh. The rebid reason given was “Optimise AS and Energy::Decrease energy band”.

There was no other significant rebidding.

Friday, 20 January

1:00 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	1442.59	5043.32	295.80
Demand (MW)	2731	2725	2635
Available capacity (MW)	3112	2898	2941
2:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	686.18	4614.70	2102.79
Demand (MW)	2823	2781	2752
Available capacity (MW)	3126	3150	2941
3:00 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	2085.17	4999.00	4998.00
Demand (MW)	2838	2800	2788
Available capacity (MW)	3098	3080	2941
3:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	3067.41	4999.98	4998.00
Demand (MW)	2861	2806	2793
Available capacity (MW)	3077	3110	2941
4:00 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	2305.23	4998.00	9631.82
Demand (MW)	2862	2833	2815
Available capacity (MW)	3134	3110	2941
4:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	932.54	4998.00	2254.07
Demand (MW)	2872	2785	2821
Available capacity (MW)	3158	3110	2941

For the second consecutive day, demand reached record levels in South Australia peaking at 2872 MW surpassing the record set the previous day by 30 MW and around 40 MW higher than the previous record set in February 2001. The high demands on the day were as forecast with temperatures reaching above 41 degrees, and around 4 degrees higher than forecast. Actual prices were generally lower than forecast during the period. Similar conditions were occurring in Victoria at the same time.

Cummins Engine Company shifted 37 MW of capacity at Angaston from prices of around $5000/MWh to approximately $10/MWh. The rebid reason given was “optimise AS and energy::decrease energy band”.

At 8.34am, International Power increased the availability of Pelican Point by 210 MW, with 170 MW of this capacity was priced at less than zero. The rebid reason given was “change in price forecast”.

There were no other significant rebids.

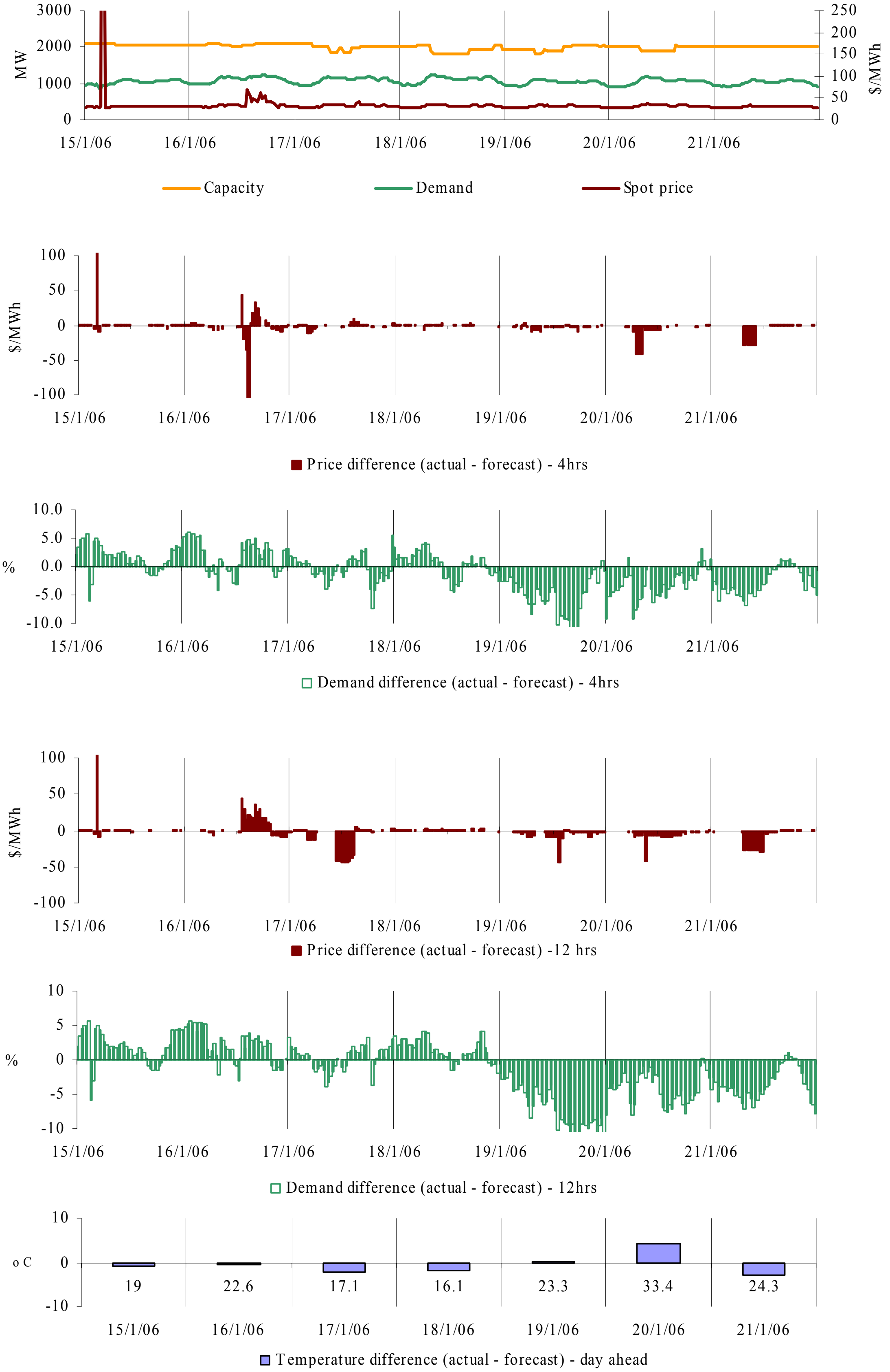
Saturday, 21 January

3:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	1882.21	9999.95	299.00
Demand (MW)	2700	2844	2728
Available capacity (MW)	2652	2636	2685

Conditions at the time saw demand peak at 2700 MW, setting a new weekend record demand and surpassing the previous record by 140 MW. Demand forecasts were around 150 MW higher than actual demand.

There was no significant rebidding.

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



There was one occasion in Tasmania where the spot price was greater than three times the weekly average price of $35/MWh.

Sunday, 15 January

4:30 am	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	1356.58	37.00	37.00
Demand (MW)	955	911	911
Available capacity (MW)	2082	2082	2082

Conditions at the time saw demand close to forecast.

A small increase in the requirement for raise 6 second frequency control service in Tasmania, coinciding with a reduction in available capacity for the service at the same time, led to a single dispatch price of $8000/MWh in the energy market and $10 000/MWh in the raise 6 second ancillary service market .

There was no significant rebidding.

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

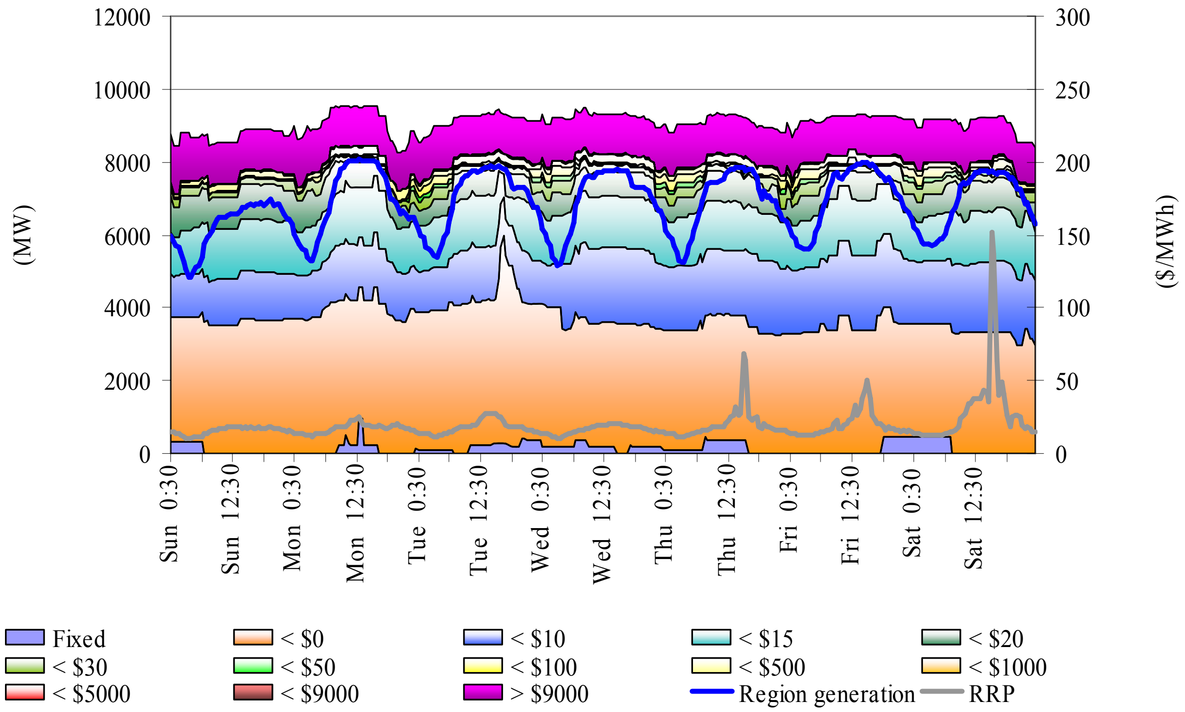


Figure 52: New South Wales closing bid prices, dispatched generation and spot price

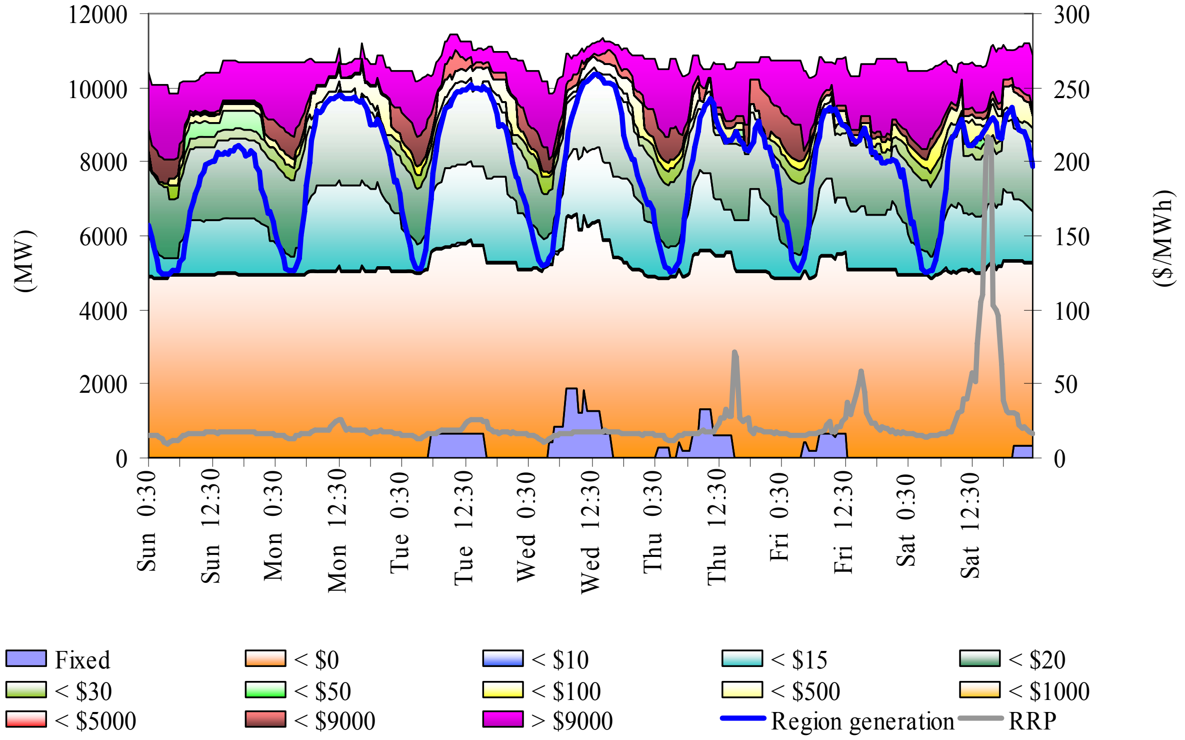


Figure 53: Victoria closing bid prices, dispatched generation and spot price

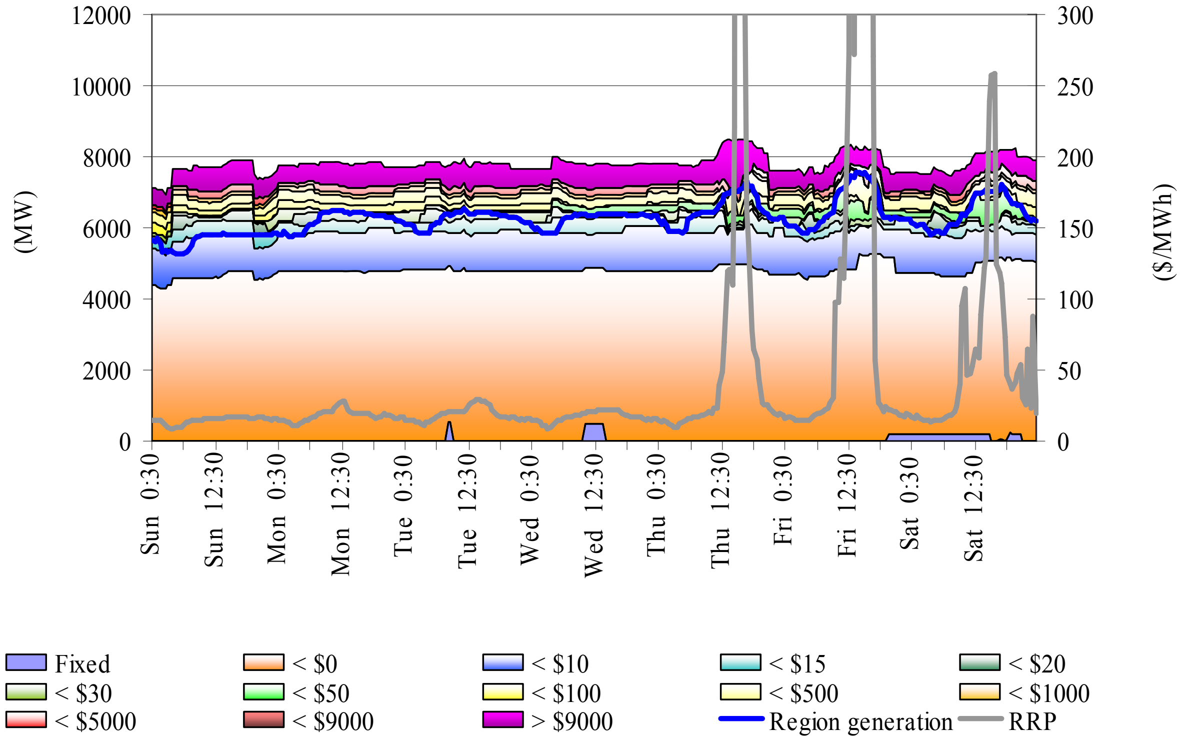


Figure 54: South Australia closing bid prices, dispatched generation and spot price

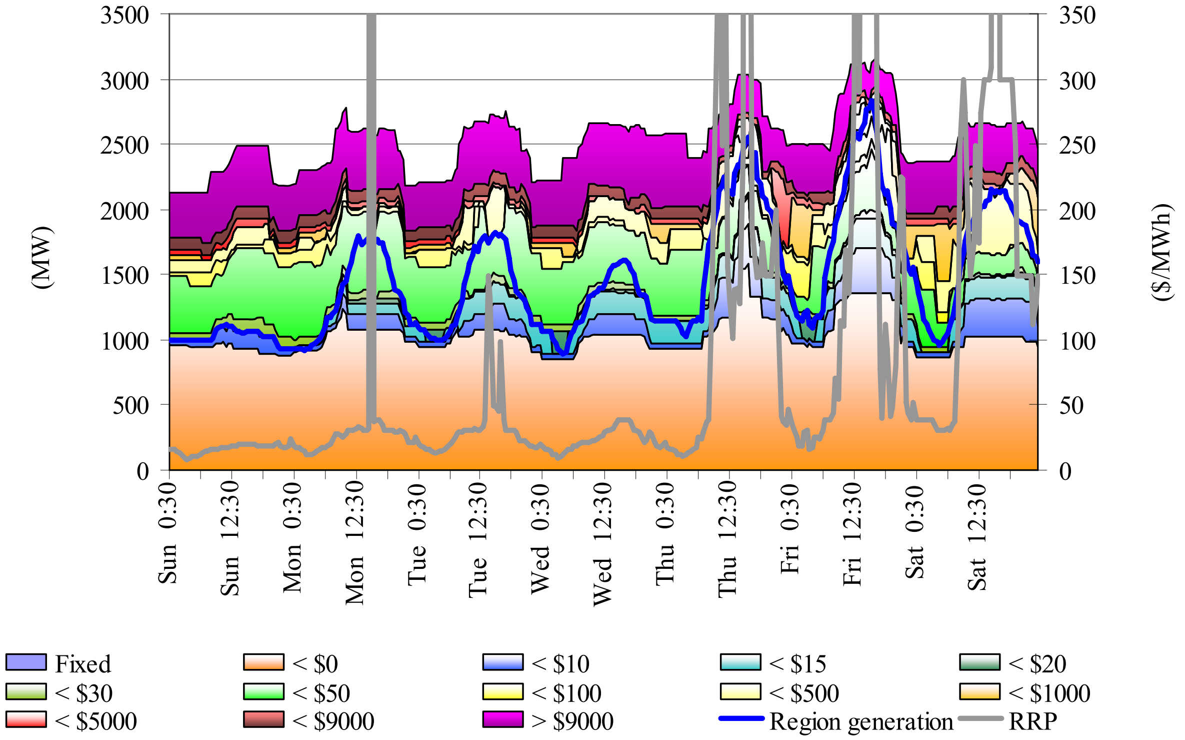
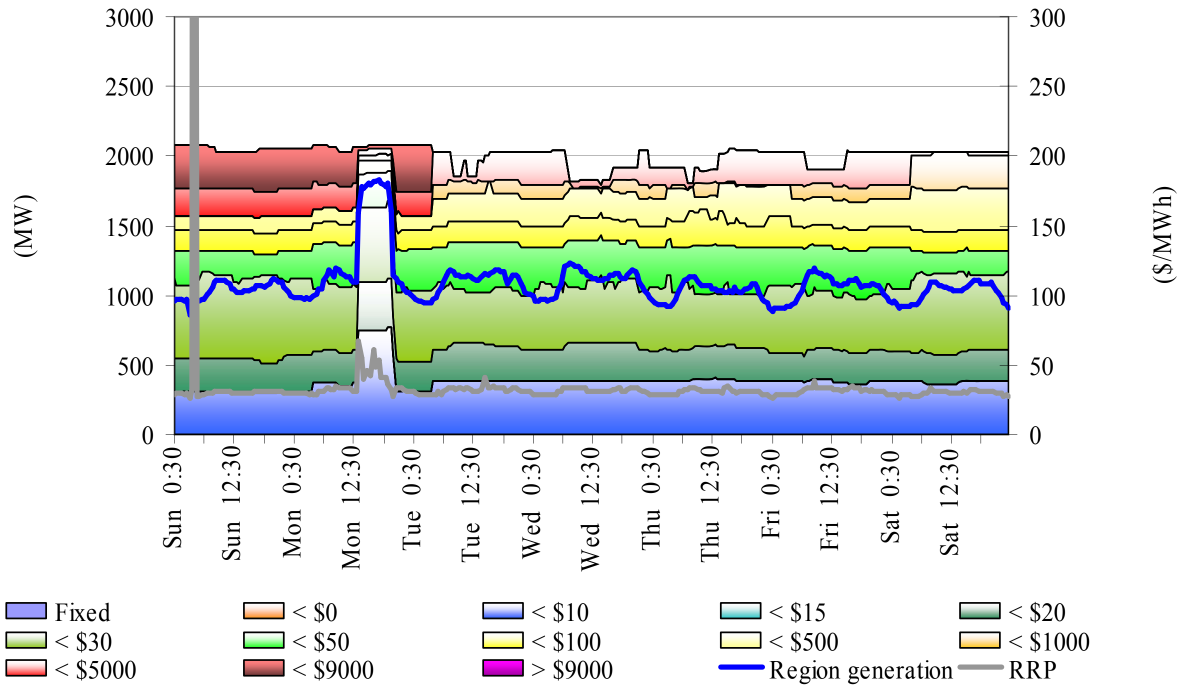


Figure 55: Tasmania closing bid prices, dispatched generation and spot price



Ancillary service market

The total cost of ancillary services on the mainland for the week was just over $200 000 or less than 0.1 per cent of the total turnover in the energy market. Figure 56 summarises the volume weighted average prices and costs for the eight frequency control ancillary services across the interconnected regions.

Figure 56: frequency control ancillary service prices and costs

	Raise 6 sec	Raise 60 sec	Raise 5 min	Raise reg	Lower 6 sec	Lower 60 sec	Lower 5 min	Lower reg
Last week	0.44	0.31	0.87	0.69	0.17	1.40	3.25	1.47
Previous week	0.79	0.42	1.11	1.16	0.21	0.35	0.57	1.66
Last quarter	1.76	0.73	1.15	1.54	0.39	2.28	5.00	1.93
Market Cost ($1000s)	20	14	56	15	1	14	55	32
% of energy market	0.01%	0.01%	0.02%	0.01%	0.00%	0.01%	0.02%	0.01%

The total cost of ancillary services in Tasmania for the week was $125 000 or 2 per cent of the total turnover in the energy market in Tasmania. Around half of this cost resulted from one dispatch interval on Sunday morning which saw the raise 6 second frequency control service price reach $10 000/MW. Figure 57 summarises for Tasmania the prices and costs for the eight frequency control ancillary services.

Figure 57: frequency control ancillary service prices and costs 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	7.53	0.45	0.47	0.52	0.54	0.49	0.50	0.63
Previous week	6.92	1.05	1.05	1.06	1.12	1.06	1.05	1.08
Last quarter	7.89	1.05	1.05	1.58	4.43	1.06	1.06	1.97
Market Cost ($1000s)	67	6	5	4	8	16	12	5
% of energy market	1.07%	0.09%	0.08%	0.07%	0.13%	0.25%	0.19%	0.08%

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

Figure 58: daily frequency control ancillary service costs

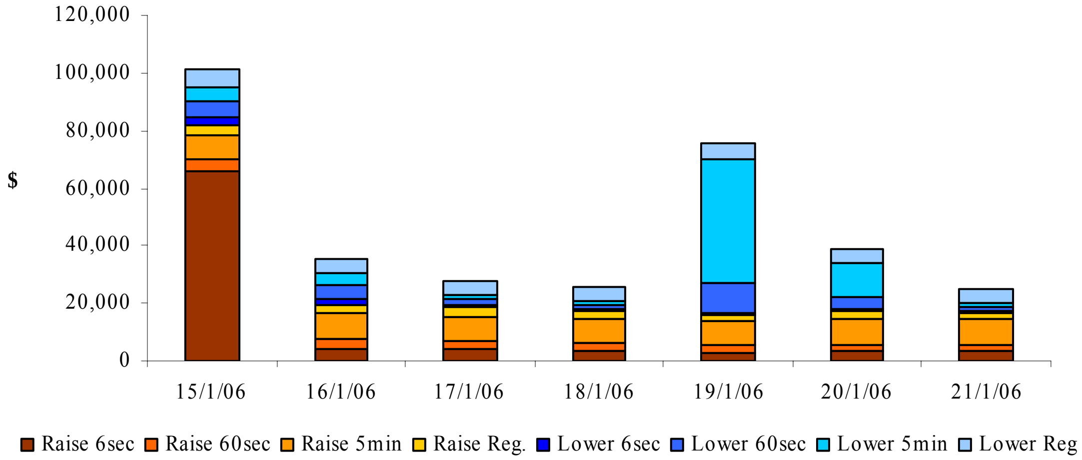
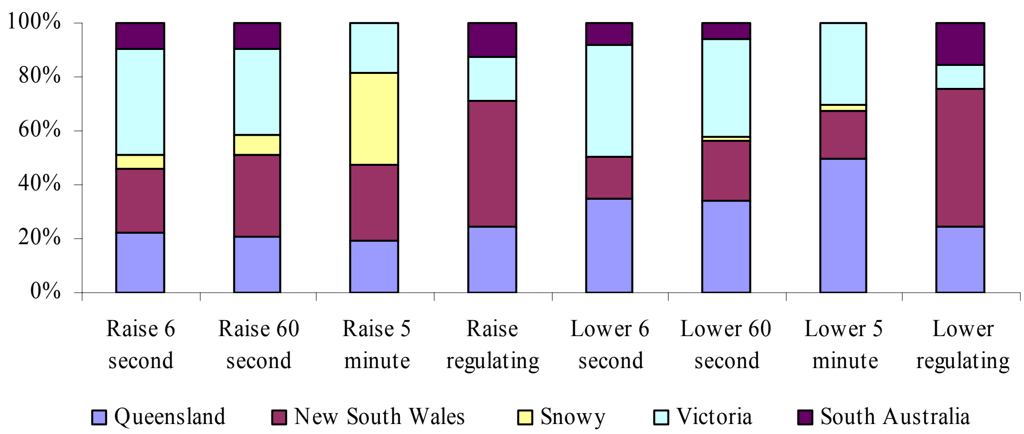


Figure 59 shows the contribution, on a percentage basis, that frequency control ancillary service providers are utilised (in each mainland region) to satisfy the total requirement for each service.

Figure 59: regional participation in ancillary services on the mainland



Figures 60 and 61 show 30-minute prices for each frequency control ancillary service throughout the week.

Figure 60: prices for raise services

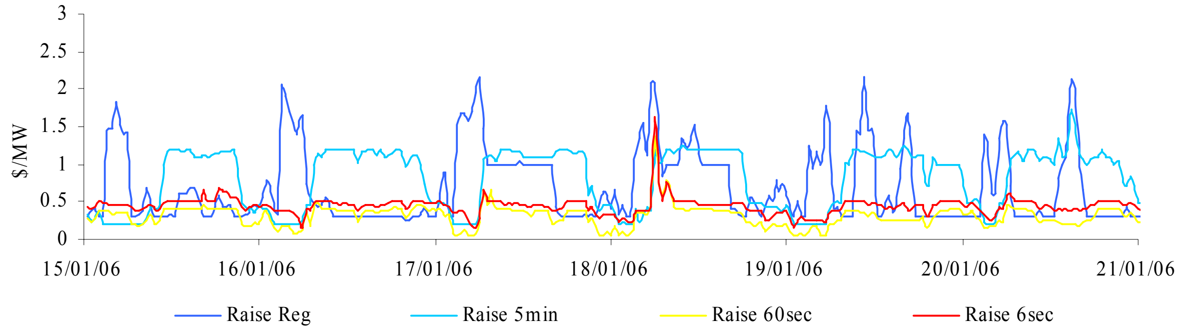


Figure 60A: prices for raise services - Tasmania

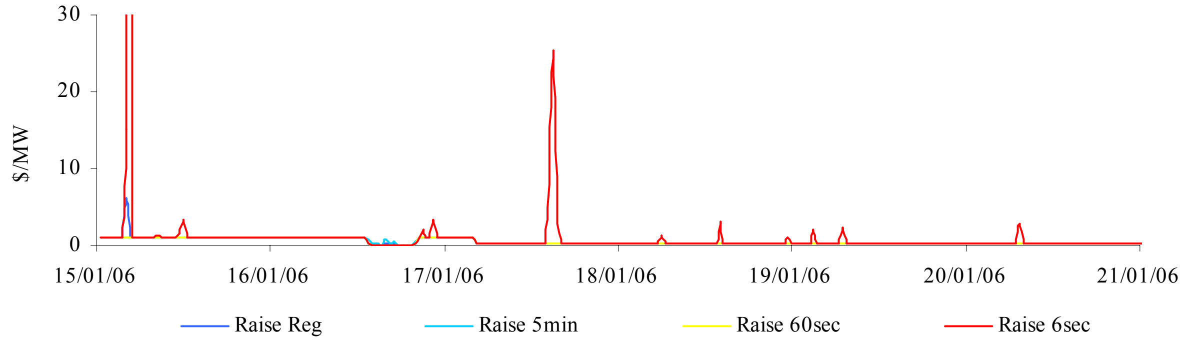


Figure 61: prices for lower services

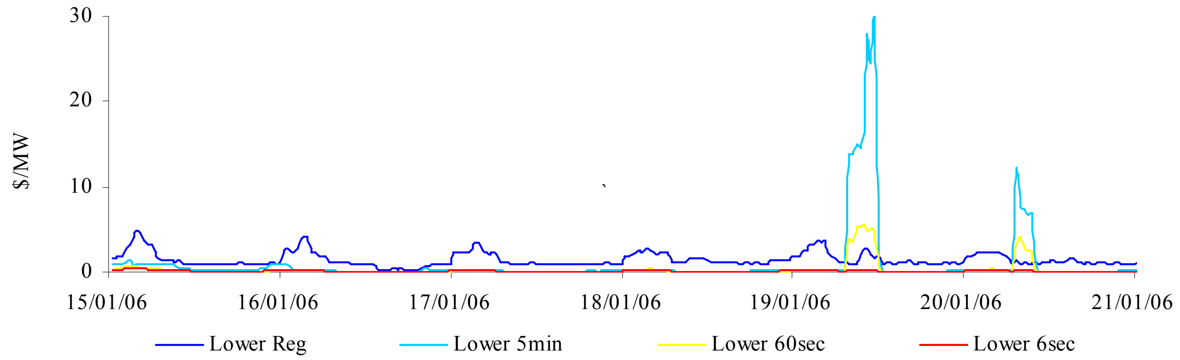
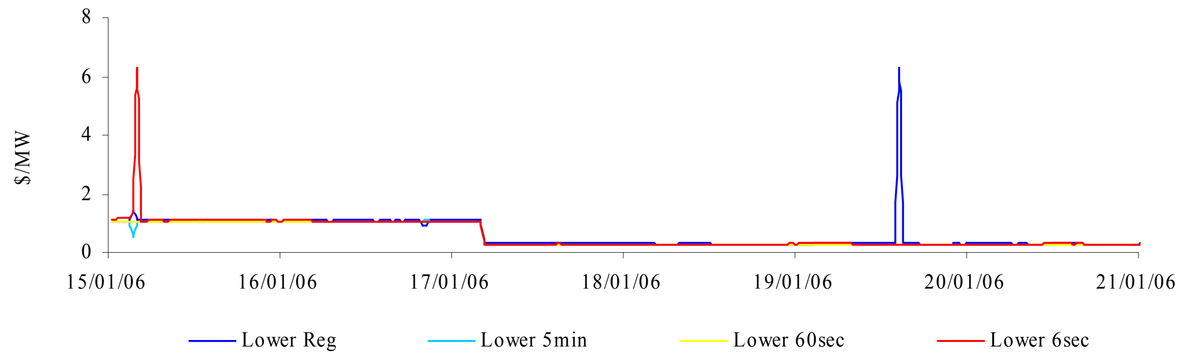


Figure 61A: prices for lower services - Tasmania



Figures 62 and 63 present for both raise and lower frequency control services the requirement, established by NEMMCO, for each service to satisfy the frequency standard.

Figure 62: raise requirements

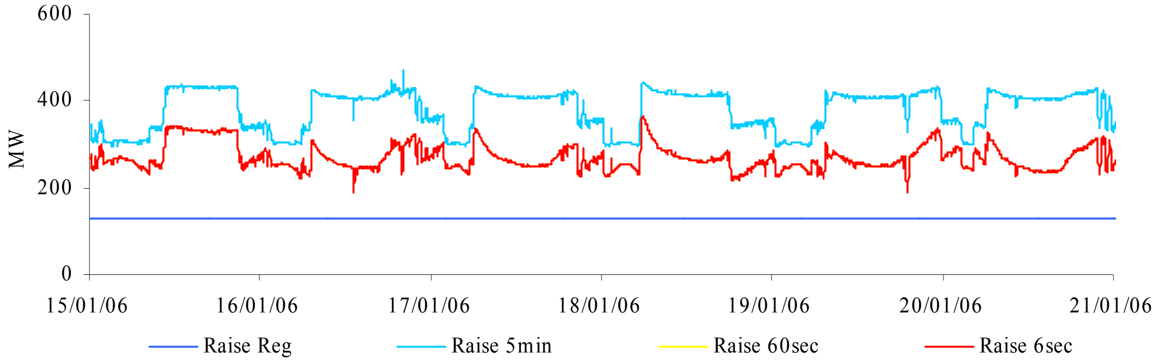


Figure 62A: raise requirements - Tasmania

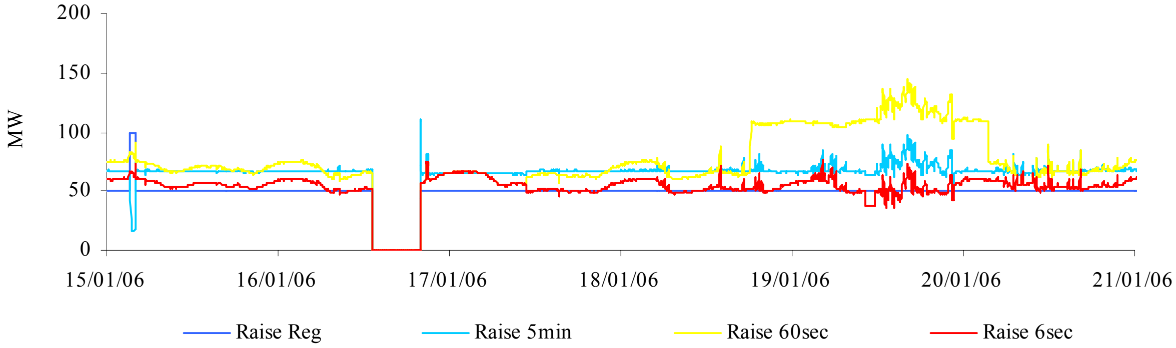


Figure 63: lower requirements

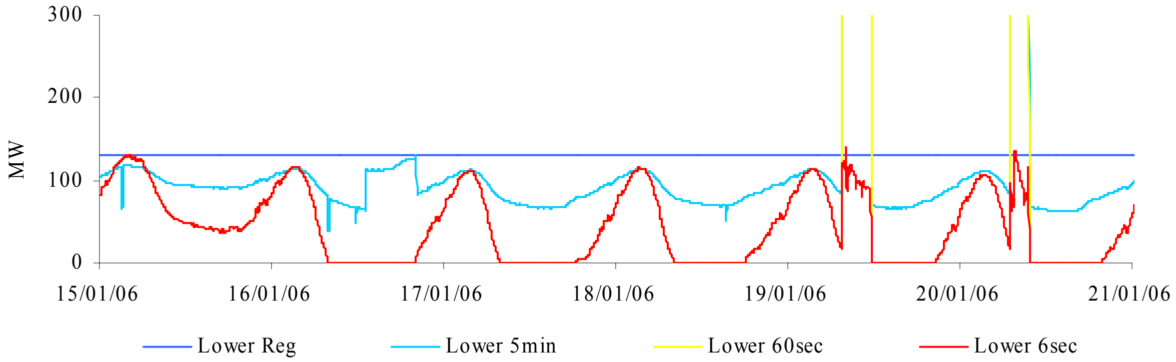
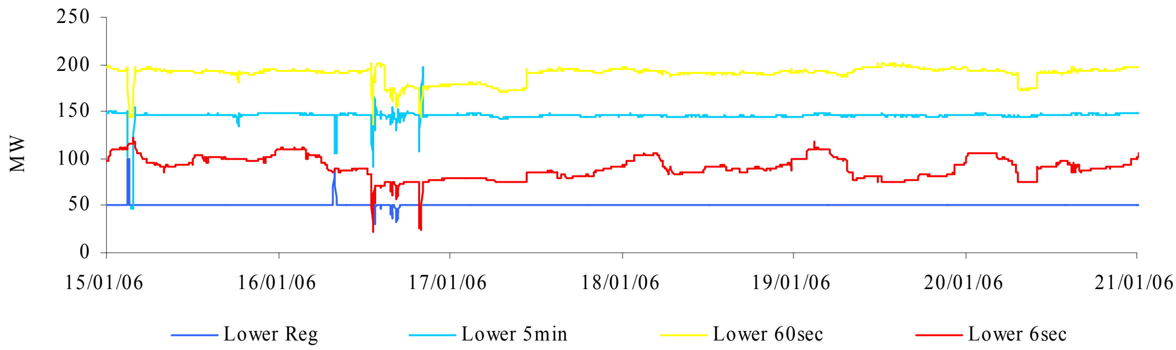


Figure 63A: lower requirements - Tasmania



Australian Energy Regulator
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