Market analysis

6 – 12 NOVEMBER 2005

A combination of warm weather and high demand in New South Wales, generator rebidding and network limitations resulted in high prices for the second consecutive week. Spot prices on both Wednesday and Thursday exceeded $5 000/MWh in New South Wales, with high prices in all other mainland regions on Wednesday. Investigations into the main contributing factors which led to the prices above $5 000/MWh, as required by clause 3.13.7 of the rules, are continuing.

Average prices for the week were $28/MWh in Queensland, $223/MWh in New South Wales, $62/MWh in Victoria and $35/MWh in South Australia.

Turnover in the energy market for the mainland was $410 million – the highest weekly total for the year. The total cost of ancillary services for the week was around $470 000 or 0.1 per cent of turnover.

The average spot price in Tasmania was $61/MWh, down slightly on the previous week. The turnover for the week was $11 million. The cost of ancillary services was around $110 000 or 1 per cent of turnover.

Demand forecasts produced 4 and 12 hours ahead varied from actual by more than 5 per cent in approximately a quarter of all trading intervals across the market. These variations were most frequent in South Australia occurring in around two thirds of all trading intervals. Significant variations between forecast and actual prices occurred in 46, or 14 per cent, of trading intervals. Demand variations were the main contributor.

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 financial year to date. 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	28	223	62	35	61
Previous week	44	158	35	35	65
Same quarter last year	48	90	38	54	-
Financial year to date	23	44	30	34	94
% change from previous week	▼36	▲42	▲76	-	▼6
% change from same quarter last year	▼41	▲149	▲62	▼34	-
% change from year to date	▼30	▲3	▼7	▼11	-

Figure 2: national demand and spot prices

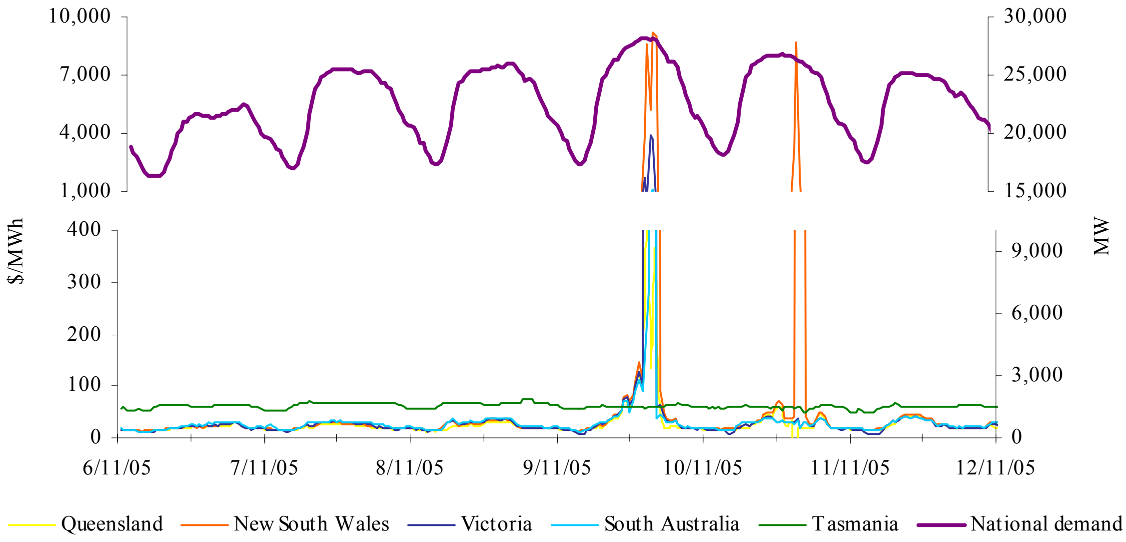


Figure 3: volatility index during peak periods

	QLD	NSW	VIC	SA	TAS
Last week	1.08	1.11	0.72	0.58	0.13
Previous week	0.72	3.22	1.79	0.66	0.18
Same quarter last year	1.13	1.23	0.96	0.77	-

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

Figure 4: Queensland

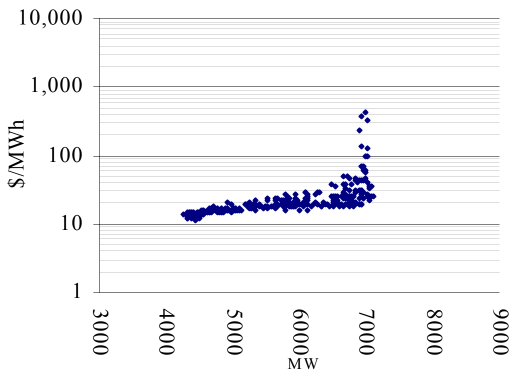


Figure 5: New South Wales

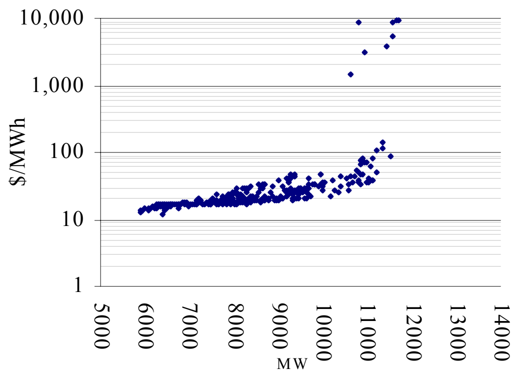


Figure 6: Victoria

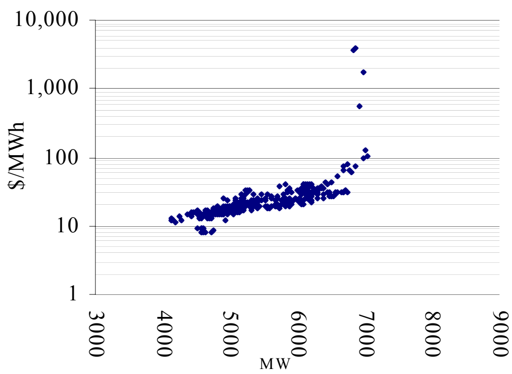


Figure 7: South Australia

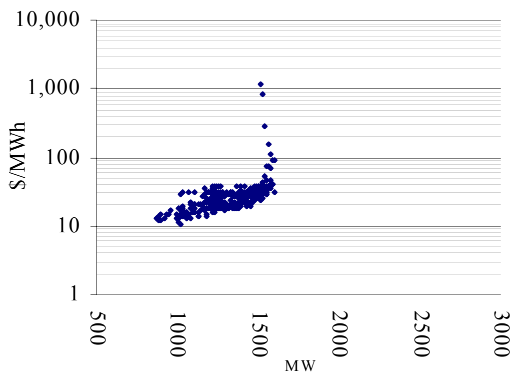
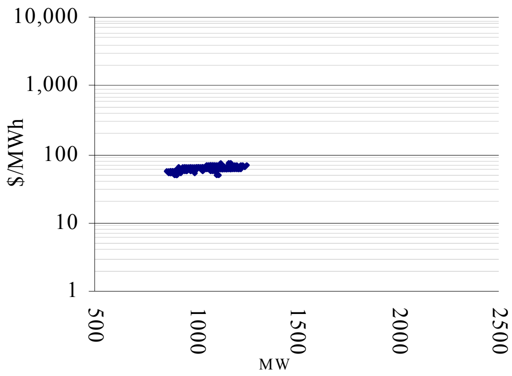


Figure 8: Tasmania



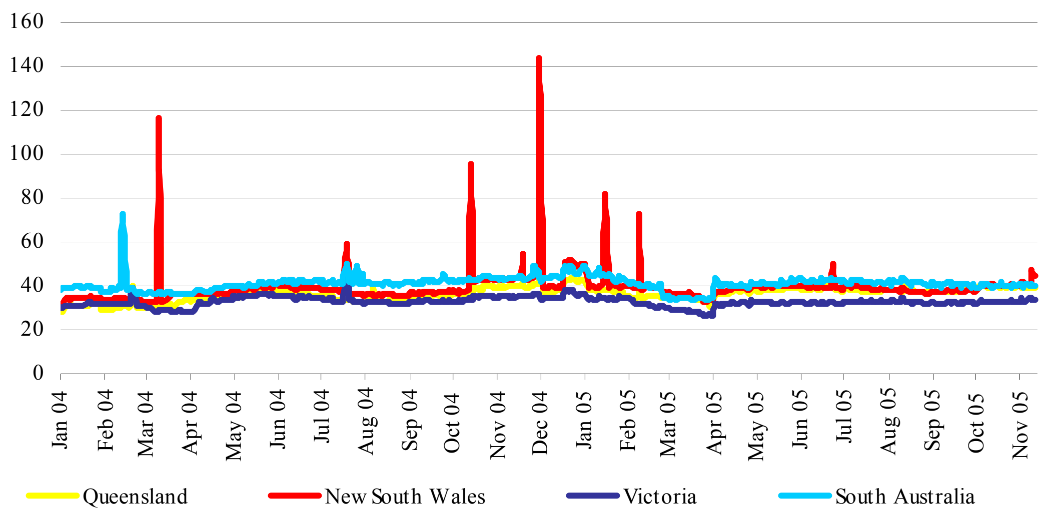
Maximum spot prices for the week were $431/MWh in Queensland, $9 167/MWh in New South Wales, $3 860/MWh in Victoria, $1 144/MWh in South Australia, and $76/MWh in Tasmania.

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	39.54	39.71	39.54	39.34	39.09
New South Wales	41.08	41.72	47.16	44.73	44.34
Victoria	34.23	34.06	34.25	33.81	33.78
South Australia	39.99	40.72	40.48	40.15	40.31

Figure 10: d-cyphaTrade WEPI



Reserve

There were no low reserve conditions forecast for 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

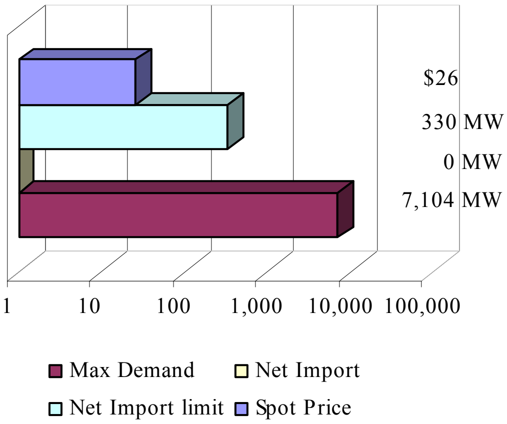


Figure 12: New South Wales

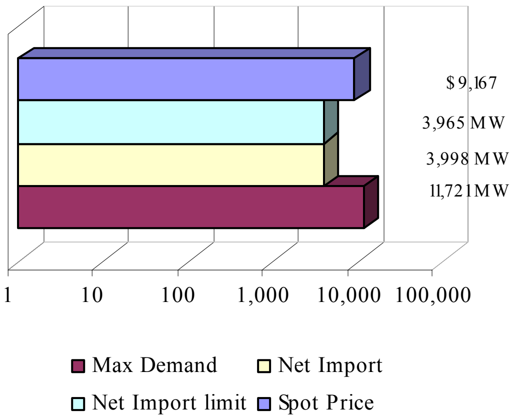


Figure 13: Victoria

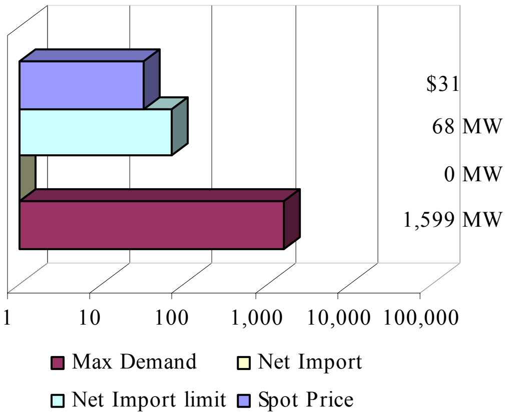
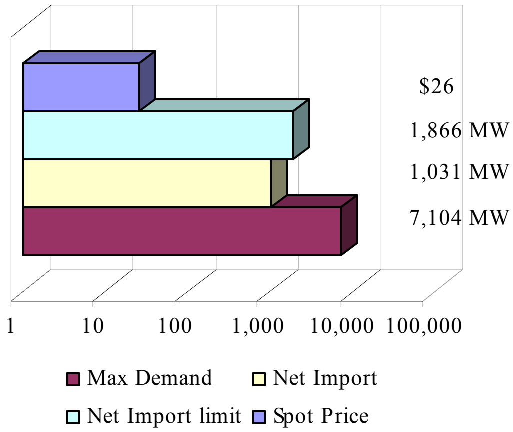


Figure 14: South Australia



In Tasmania, demand reached a maximum of 1 252MW at 7.30am on Tuesday, 8 November. The spot price at the time was $67/MWh.

Price variations

There were 46 trading intervals where actual prices significantly varied from forecasts made 4 and 12 hours ahead of dispatch. 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 100 per cent have been capped.

Figure 15: Queensland

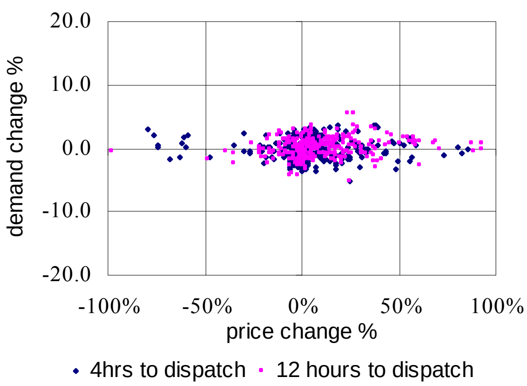


Figure 16: New South Wales

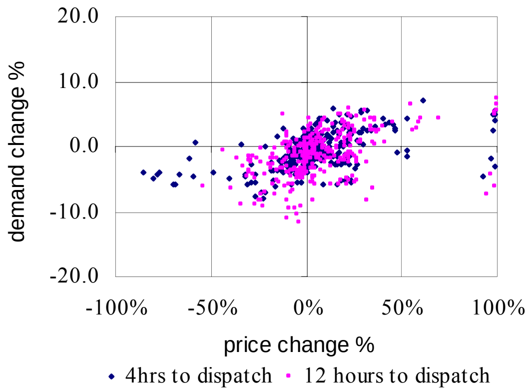


Figure 17: Victoria

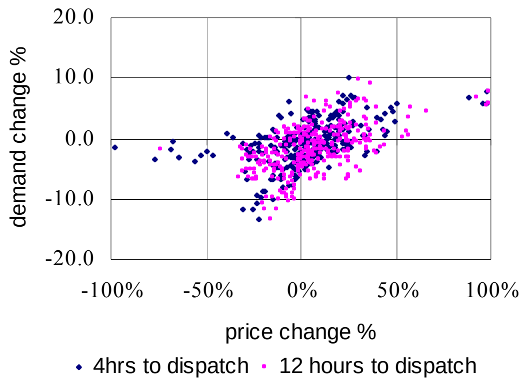


Figure 18: South Australia

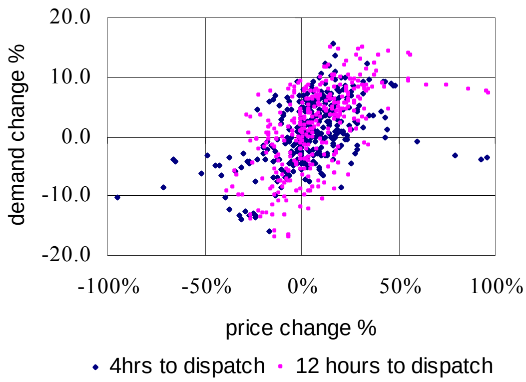


Figure 19: Tasmania

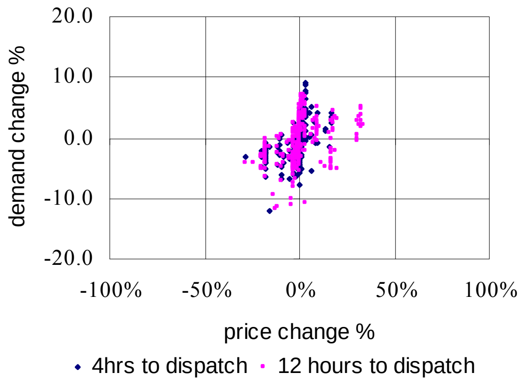
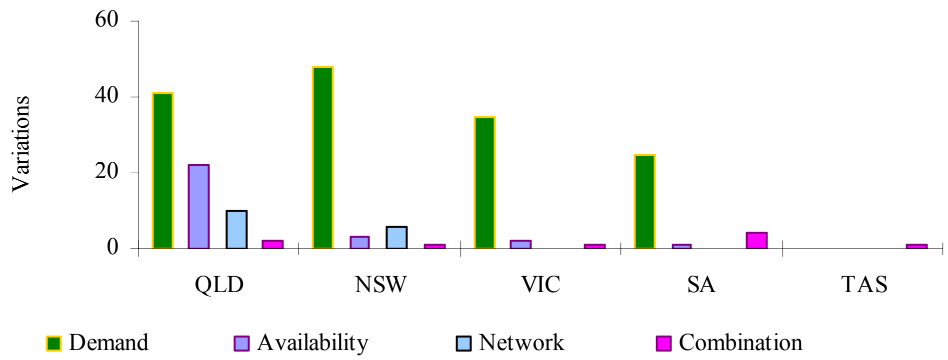


Figure 20 summarises the number and most probable reason for variations between forecast and actual prices.

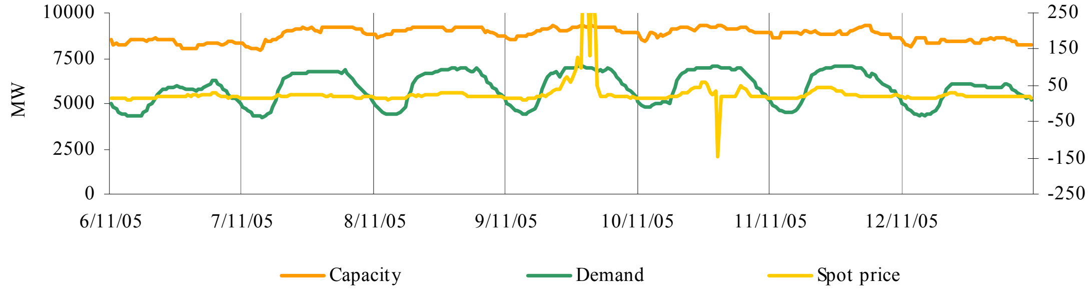
Figure 20: reasons for variations between forecast and actual prices

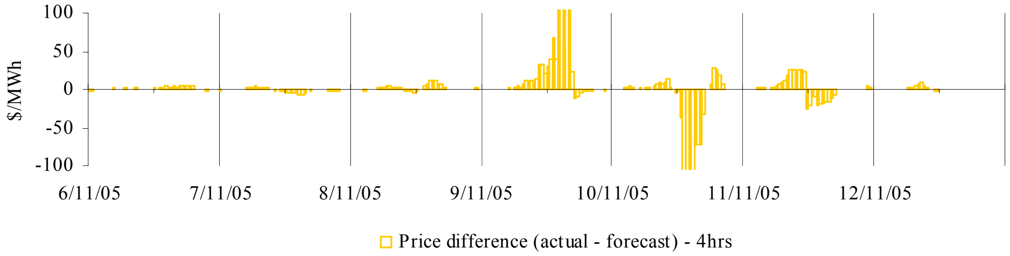


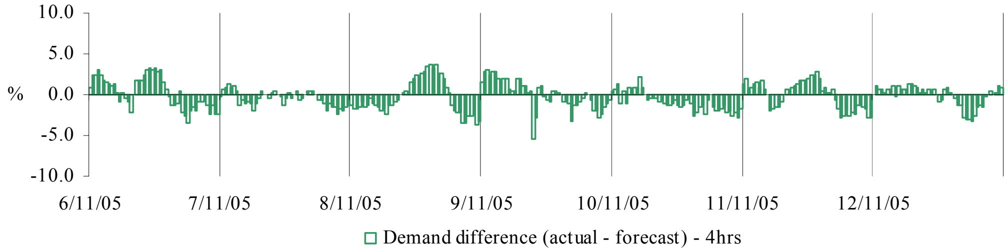
Price and demand

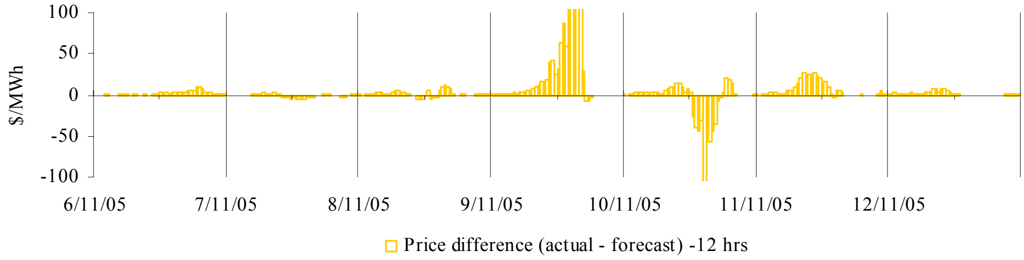
Figures 21 - 50 set out details of spot prices and demand on a regional basis. They include the actual spot price, actual demand outcomes and variation from forecasts made 4 and 12 hours ahead of dispatch on a daily basis. The differences between the maximum temperature and the temperature forecast at 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.

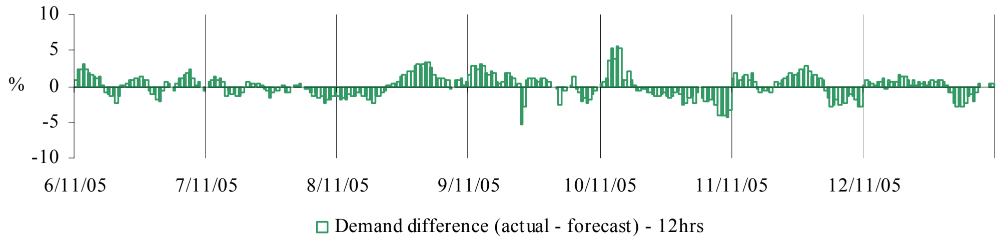
Figures 21-26: Queensland actual spot price, demand and forecast differences

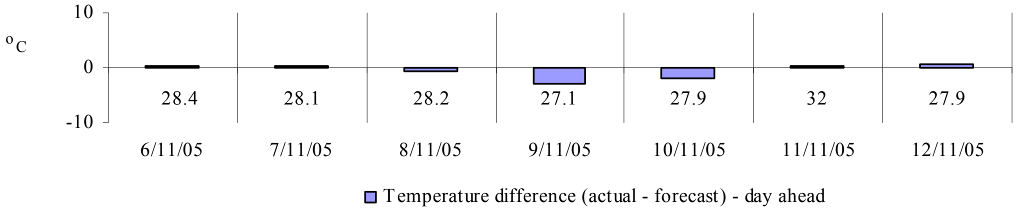












There were 8 occasions in Queensland where the spot price was greater than three times the weekly average price of $28/MWh. These all occurred on Wednesday afternoon.

Wednesday, 9 November

1:00 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	94.15	53.86	29.81
Demand (MW)	6 996	7 053	6 952
Available capacity (MW)	9 171	9 160	9 170
1:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	127.02	60.22	39.25
Demand (MW)	7 029	6 998	6 947
Available capacity (MW)	9 181	8 955	8 965
2:00 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	99.20	60.23	39.25
Demand (MW)	7 026	7 003	6 953
Available capacity (MW)	9 324	9 121	9 109
2:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	314.84	60.29	39.25
Demand (MW)	7 022	7 011	6 962
Available capacity (MW)	9 304	9 130	9 109
3:00 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	431.33	60.91	29.81
Demand (MW)	7 002	7 007	6 956
Available capacity (MW)	9 178	9 328	9 314
3:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	133.43	76.79	38.28
Demand (MW)	6 938	6 996	6 946
Available capacity (MW)	9 292	9 317	9 314
4:00 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	367.37	63.24	25.20
Demand (MW)	6 933	6 991	6 945
Available capacity (MW)	9 288	9 347	9 314
4:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	226.77	60.67	25.20
Demand (MW)	6 910	6 991	6 942
Available capacity (MW)	9 244	9 347	9 314

Conditions at the time saw demand as forecast, with prices reflecting the extreme conditions in New South Wales. A planned network outage, from 7am to 5 pm, between Gladstone and Gin Gin reduced the transfer capability from central to south Queensland. As a result more than 2 000MW of generation capacity in central Queensland was rebid to zero or below, mostly from prices of less than $20/MWh.

At 7.43am, CS Energy rebid Callide unit B1 at fixed output of 350MW. This rebid was effective until 3.30 pm. The reason given was "Call B1 performance testing". At 10.53 am, 165MW of capacity at Callide B2 was rebid from prices of less than $20/MWh to prices below zero. The rebid reason given was "Callide B response to C to S constraint".

At 8.41am, Enertrade began repricing capacity, at times as much as 950MW, to prices below zero at Gladstone and Yabulu. The rebid reasons given included "NEMMCO constraint::Changed MW distrib". Most of this capacity had previously been priced at less than $20/MWh.

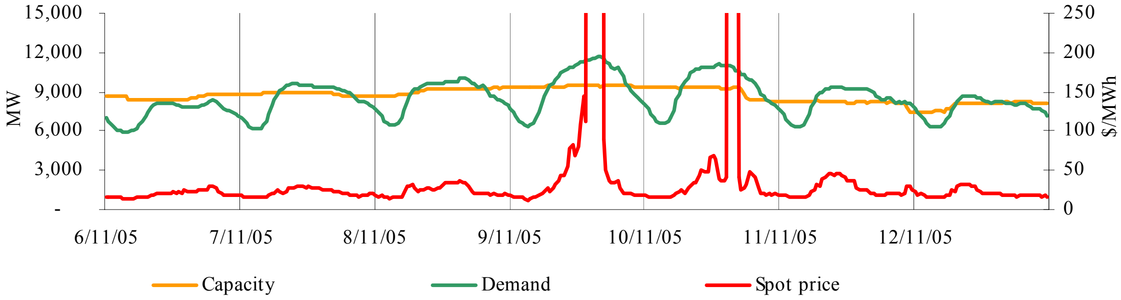
From 8.46am, Stanwell Energy began shifting capacity into prices below zero, at times as much as 700MW was moved from prices of less than $20/MWh. The rebid reasons given included “Manage network constraints” and “constraint management”.

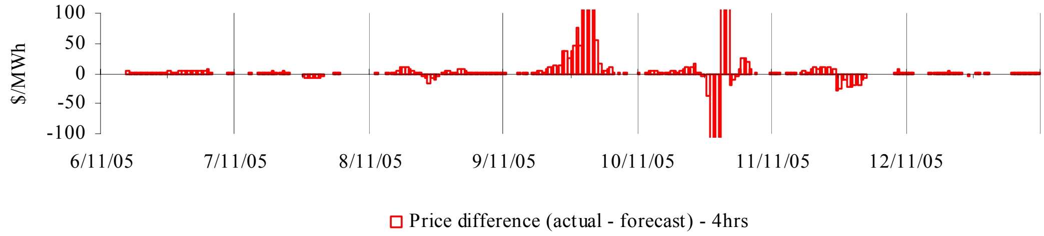
Over two rebids at 11.02am and 12.13pm 192MW of capacity at Callide C unit 3 was rebid from prices of less than $20/MWh to below zero. The rebid reason given was “Cal C response to C to S constraint” and “noon prd forecast”. An expected 205MW reduction in the availability of this unit for 1.30pm was removed by a rebid at 11.18am. The rebid reason given was “Deload not required”.

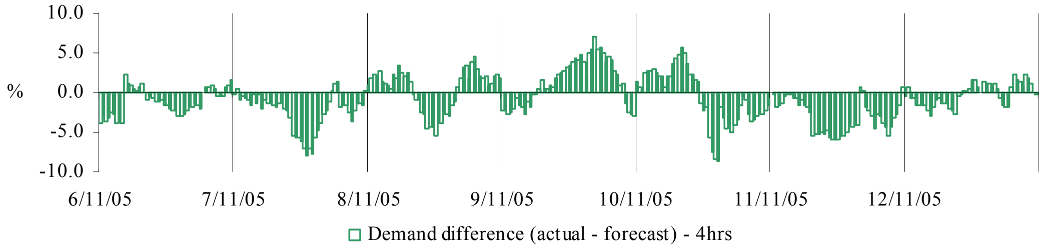
From 2.18pm, as much as 51MW of capacity across the Swanbank B units was rebid by CS Energy from prices less than $30/MWh into prices above $4 000/MWh. The rebid reason given was “Swan B response to interconnector constraint”.

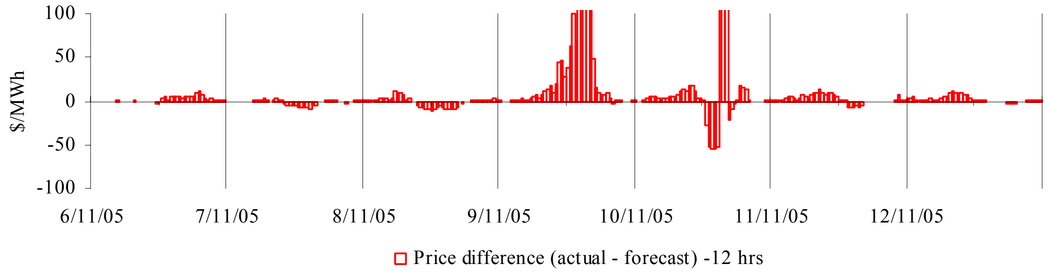
There was no other significant rebidding.

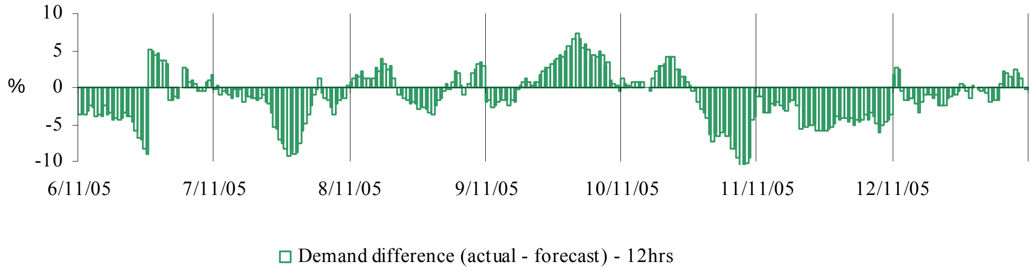
Figures 27-32 New South Wales actual spot price, demand and forecast differences

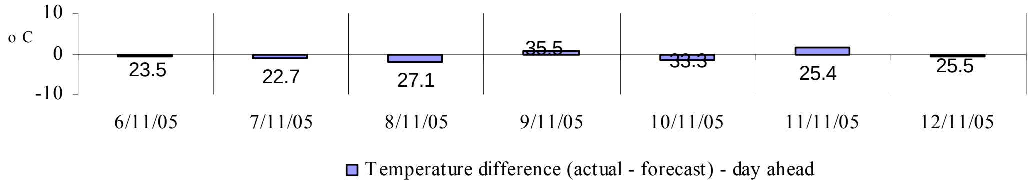












There were 8 occasions in New South Wales where the spot price was greater than three times the weekly average price of $223/MWh. These occurred on Wednesday and Thursday afternoon.

Wednesday, 9 November

2:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	3 933.05	67.46	44.82
Demand (MW)	11 435	10 883	10 884
Available capacity (MW)	9 444	9 444	9 474
3:00 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	8 647.59	68.77	44.87
Demand (MW)	11 570	11 123	10 923
Available capacity (MW)	9 444	9 444	9 474
3:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	5 217.61	90.98	43.90
Demand (MW)	11 566	11 297	10 961
Available capacity (MW)	9 444	9 444	9 474
4:00 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	9 166.67	74.28	45.15
Demand (MW)	11 721	11 140	10 955
Available capacity (MW)	9 443	9 444	9 474
4:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	9 036.06	70.12	44.16
Demand (MW)	11 677	11 039	10 822
Available capacity (MW)	9 415	9 444	9 474

Temperatures reached 35 degrees on the day with demand reaching a high of 11 721 MW. Demand was 600MW higher than forecast four hours to dispatch with little capacity priced between $25/MWh and $5 000/MWh. From 2.10pm, flows into New South Wales were constrained on all three interconnectors and, at times, most of the generation within New South Wales was also constrained.

At 10.30am, 1.55pm and 3.10pm, Macquarie Generation rebid as much as 840MW of capacity from prices of less than $20/MWh to prices of more than $8 000/MWh. The rebid reasons included “RP/Volume tradeoff – Load expected to vary from forecast”, “RP/Volume trade off – NEMMCO load forecasts increased” and “RP/Volume trade off – Demand management occurring”.

At 2.08pm, effective immediately, Snowy Hydro, rebid 658MW of capacity at Tumut3 from prices of $92/MWh, $279/MWh and $760/MWh to prices of $7 442/MWh. The rebid reason given was “M:Snowy –NSW const: Bandsift up”. Up to 150 MW was shifted back into lower prices over subsequent rebids.

At 2.16pm, effective 2.25pm, Eraring Energy rebid 100MW from prices of less than $30/MWh to prices above $8 000/MWh. The rebid reason given was “Increased likelihood of increased profit”.

There was no other significant rebidding.

Thursday, 10 November

3:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	3175.43	102.49	91.99
Demand (MW)	10 947	11 144	11 408
Available capacity (MW)	9 224	9 404	9 404
4:00 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	8650.67	102.48	101.92
Demand (MW)	10 821	11 157	11 502
Available capacity (MW)	9 344	9 404	9 404
4:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	1467.97	101.30	72.60
Demand (MW)	10 622	11 112	11 408
Available capacity (MW)	9 354	9 404	9 404

Conditions at the time saw the warm weather continue for the second consecutive day. Demand, however, was as much as 500MW lower than forecast four hours ahead. There was little to no capacity priced between $24/MWh and $6 000/MWh.

At 8.40am, Macquarie Generation rebid as much as 460MW of capacity from prices of less than $100/MWh to prices of more than $800/MWh. The rebid was effective between 10am and 5pm, the reason given was “RP/Volume tradeoff - load expected to vary from forecast”. The most recent demand forecast at the time of this rebid, published at around 8.30am, was forecasting demand for 4.30pm, 900MW higher than actual. At 9am, the demand forecast was increased leading to forecast demands for 4.30pm, 1,300MW higher than actual. Following this increase and the rebid by Macquarie Generation, price forecasts increased to be above $5,000/MWh between 1.30pm and 4.30pm. At times, prices of $10 000/MWh were forecast.

At 11am, the demand forecast was revised down, but remained as much as 500MW higher than actual during this period. Forecast prices reduced following this revision. At 12.58pm, Macquarie Generation rebid as much as 670MW of capacity from prices above $800/MWh to prices below $20/MWh. The rebid reason given was “RP/Volume tradeoff – NEMMCO load forecast reduced”.

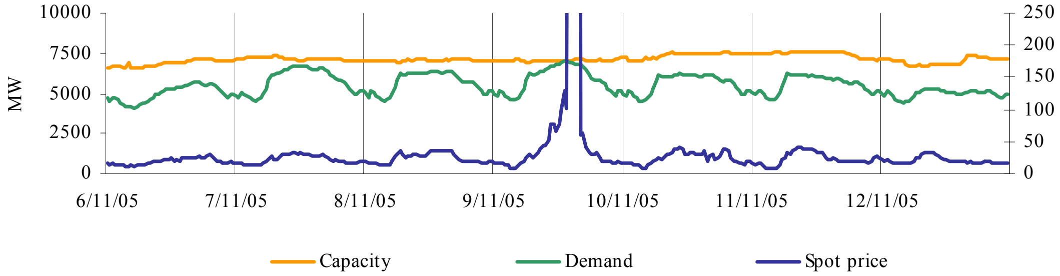
Delta Electricity reduced the availability of Wallerawang unit 8 by as much as 180MW at 2.19pm. All of this capacity was priced at less than $20/MWh. The rebid reason given was “Milling capacity coal feeders::Capacity limit change”.

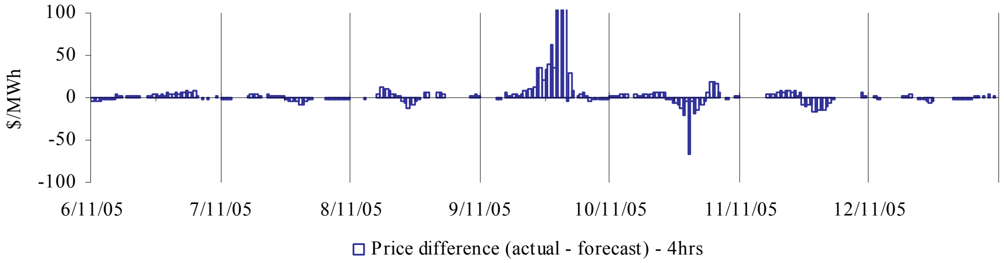
At 2.55pm, flows into New South Wales across the Queensland to New South Wales interconnector were reduced by more than 500MW following advice from both Transgrid and Powerlink of lightning in the vicinity of the interconnector. The lightning ceased to be a problem around 6pm.

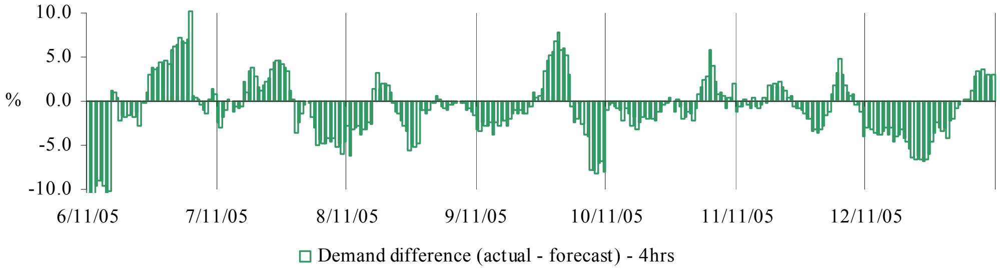
At 2.59pm, effective 3.10pm, Macquarie Generation shifted 810MW of capacity from prices of less than $20/MWh to prices above $4 700/MWh. The rebid reason given was “RP/Volume tradeoff – Management of constraints”.

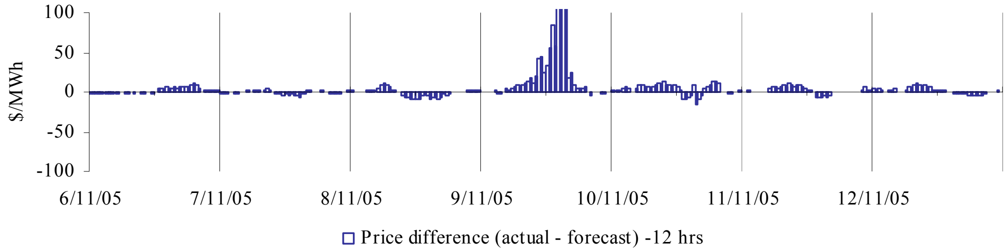
There was no other significant rebidding.

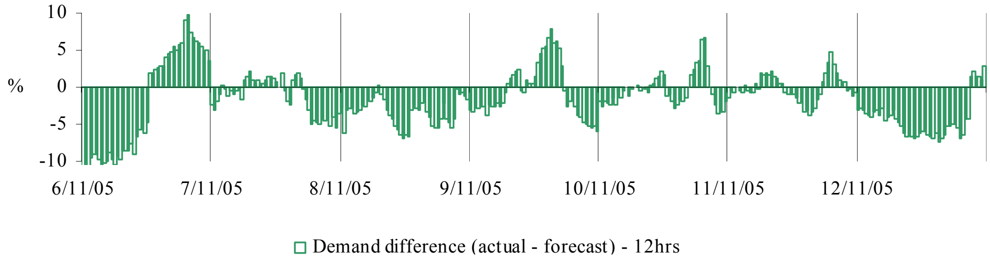
Figures 33-38: Victoria actual spot price, demand and forecast differences

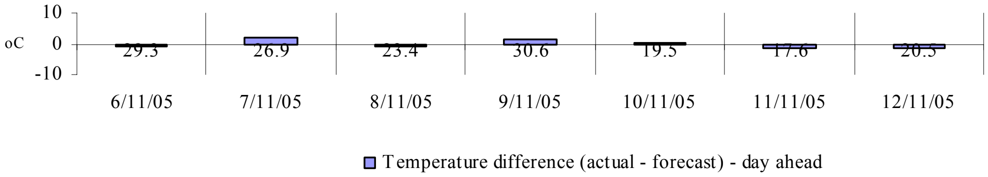












There were 4 occasions in Victoria where the spot price was greater than three times the weekly average price of $62/MWh. These occurred on Wednesday afternoon.

Wednesday, 9 November

2:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	1 687.66	64.76	42.16
Demand (MW)	6 967	6 571	6 578
Available capacity (MW)	7 030	7 035	7 269
3:00 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	562.49	63.46	41.74
Demand (MW)	6 922	6 455	6 457
Available capacity (MW)	7 066	7 027	7 269
3:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	3 859.73	79.57	40.80
Demand (MW)	6 859	6 329	6 327
Available capacity (MW)	7 108	7 090	7 260
4:00 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	3 746.55	66.08	42.19
Demand (MW)	6 835	6 439	6 436
Available capacity (MW)	7 119	7 065	7 220

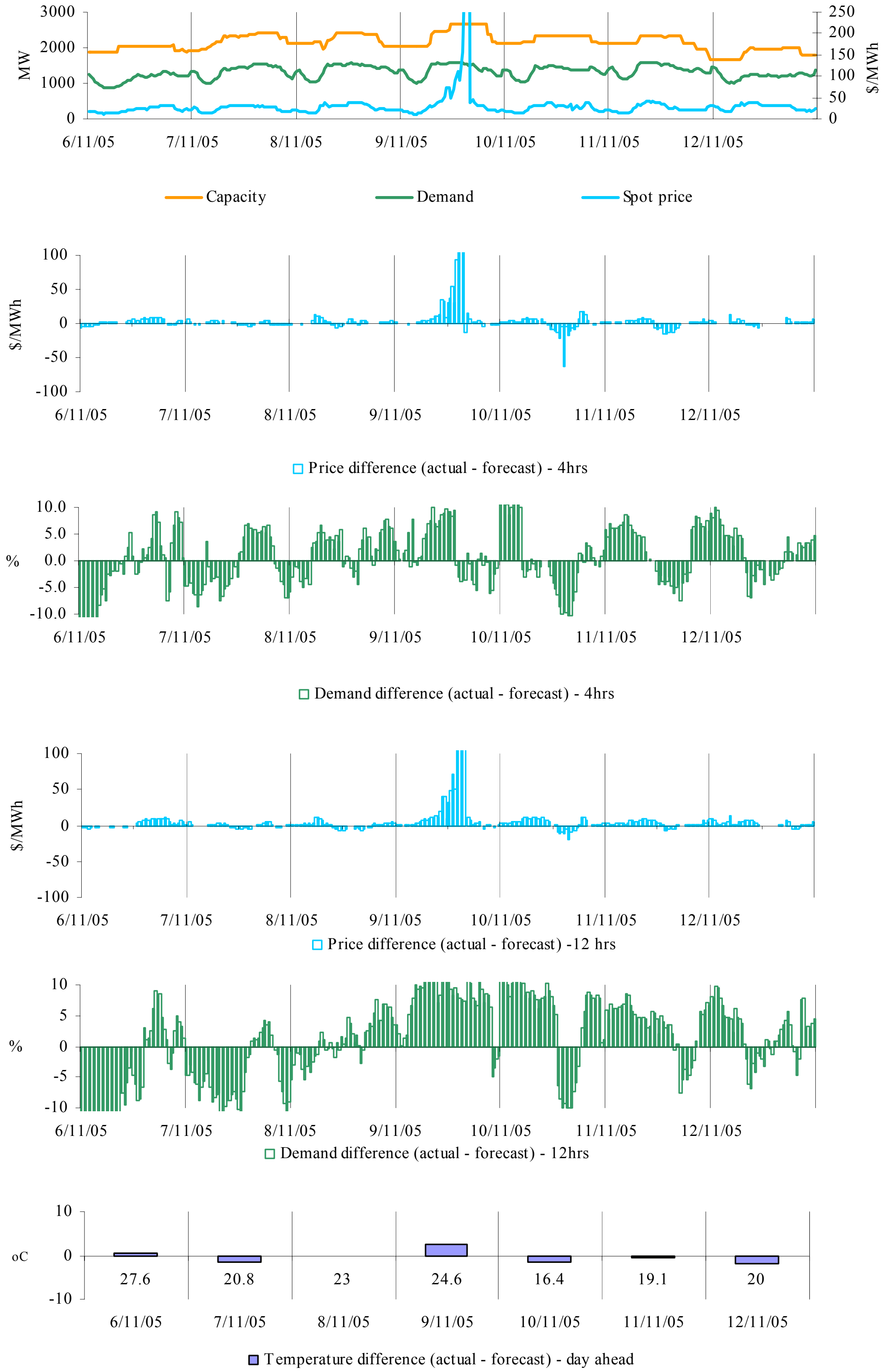
Conditions at the time saw demand as much as 500MW higher than forecast four hours to dispatch. Prices reflected the extreme conditions in New South Wales.

From 12.30pm, Ecogen Energy rebid around of 430MW from prices between $100/MWh and $300/MWh to close to zero committing generation at Jeeralang A and B. The rebid reasons given included “Adj to unit commitment due to PD conditions”. At 2.58pm, this capacity was further rebid from prices around to zero to prices close to the price floor. The rebid reason given was “Adj to unit commitment due to Mkt conditions”.

Over three rebids, at 2.23pm, 2.38pm and 2.52pm, LYMMCO rebid a total of 243MW of capacity at Loy Yang A from prices of less than $100/MWh to prices above $9 000/MWh. The rebid reasons given were “Binding interconnectors”, ‘Binding interconnectors and neg settlement situation” and “Binding interconnectors and falling Vic RRP”.

There was no other significant rebidding.

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



There were 5 occasions in South Australia where the spot price was greater than three times the weekly average price of $35/MWh. These occurred on Wednesday afternoon.

Wednesday, 9 November

1:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	110.61	56.94	39.31
Demand (MW)	1 579	1 446	1 446
Available capacity (MW)	2 655	2 460	2 466
2:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	154.57	61.82	38.30
Demand (MW)	1 569	1 581	1 436
Available capacity (MW)	2 655	2 445	2 466
3:00 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	284.14	57.66	38.10
Demand (MW)	1 542	1 590	1 421
Available capacity (MW)	2 647	2 657	2 466
3:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	853.79	63.92	38.00
Demand (MW)	1 527	1 585	1 412
Available capacity (MW)	2 655	2 655	2 466
4:00 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	1143.97	51.01	38.10
Demand (MW)	1 513	1 568	1 401
Available capacity (MW)	2 655	2 655	2 466

Conditions at the time saw demand close to forecast, with prices reflecting the extreme conditions in New South Wales. Flows into Victoria across the Heywood interconnector were at its nominal limit of 300MW for much of the afternoon. Flows of up to 120 MW into Victoria also occurred on MurrayLink during this period.

At 10.10am, International Power increased the availability of Pelican Point by 214 MW to 450 MW. Over a number of rebids 330 MW of capacity was priced to less than zero and the remainder to the price cap. The rebid reasons given were "Change in price forecast" and “Constrained interconnector”.

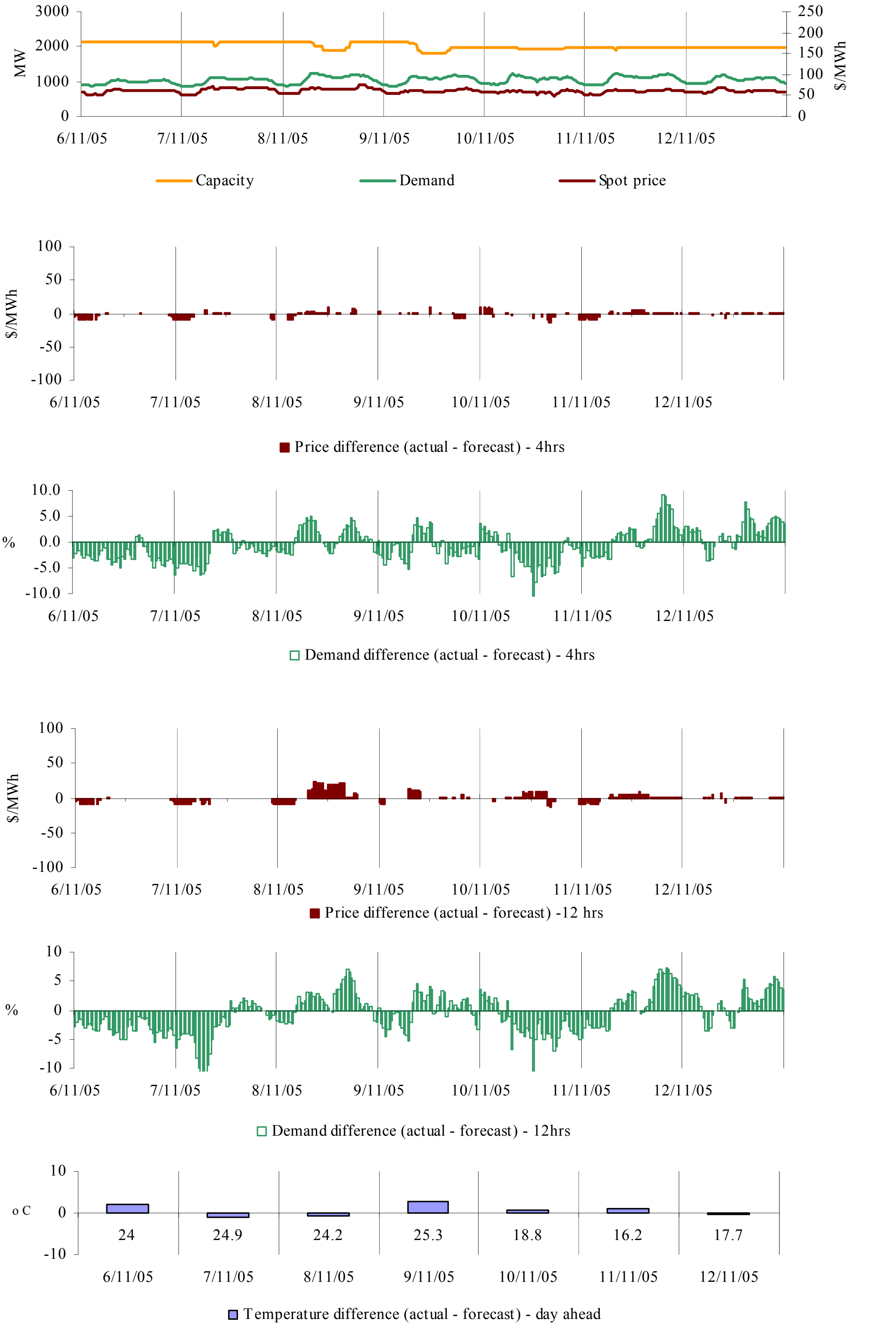
Origin Energy committed a total of 88MW of capacity at Quarantine over two rebids at 10.25am and 10.52am, shifting this capacity from prices of $9 000/MWh to zero. The rebid reason given was "Est (N) change in PDS".

At 11.46am, NRG Flinders rebid 34MW of capacity at Osborne from prices of $51/MWh to prices of $150/MWh. This rebid was effective until 3pm, the reason given was "Avoid cycling of OCPL plant".

From 12.48pm, TRU Energy began shifting capacity into prices above $9 000/MWh at Torrens Island. By 3.20pm, with rebids made at 2.36pm, 3.08pm and 3.10pm, 120MW of capacity was shifted from prices of less than $40/MWh to prices of $600/MWh and above $9 000/MWh. The rebid reasons given were "Market conditions-changed conditions".

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 $61/MWh.

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

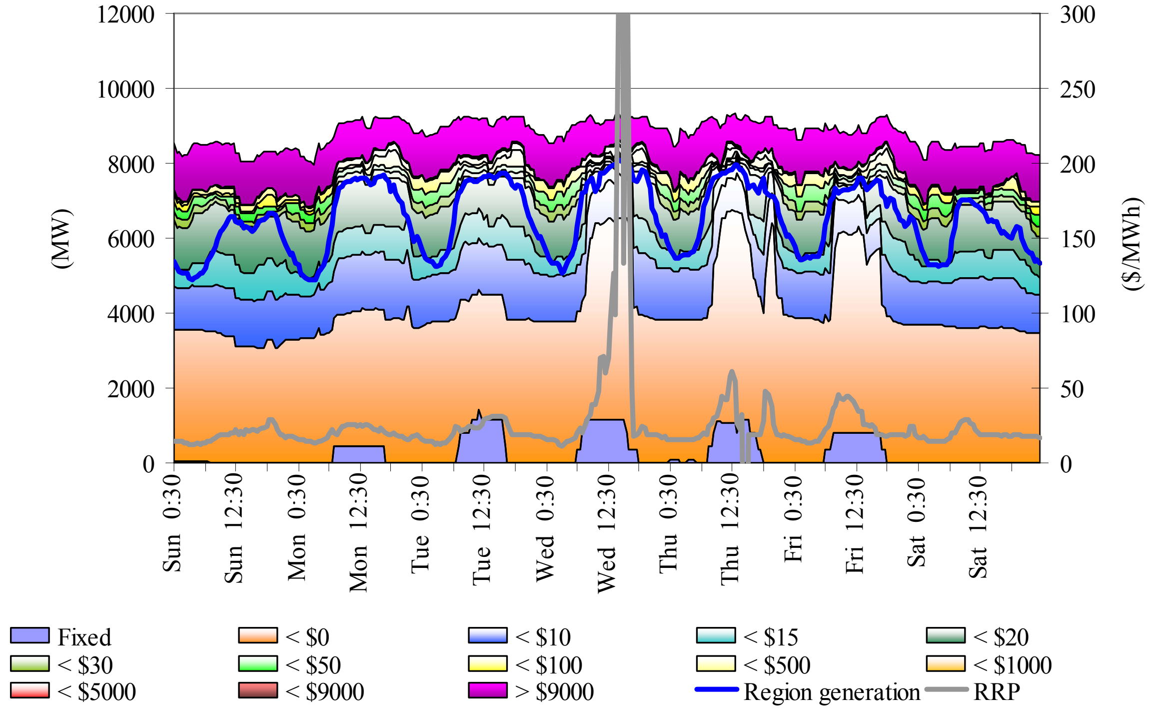


Figure 52: New South Wales closing bid prices, dispatched generation and spot price

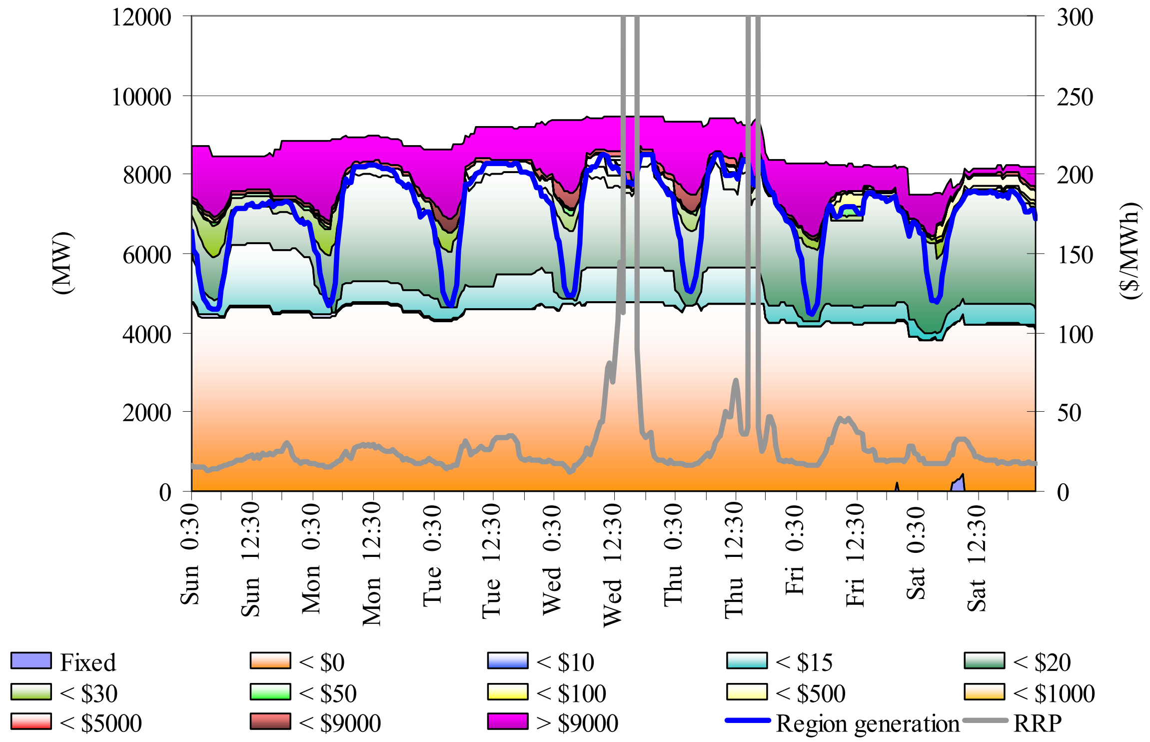


Figure 53: Victoria closing bid prices, dispatched generation and spot price

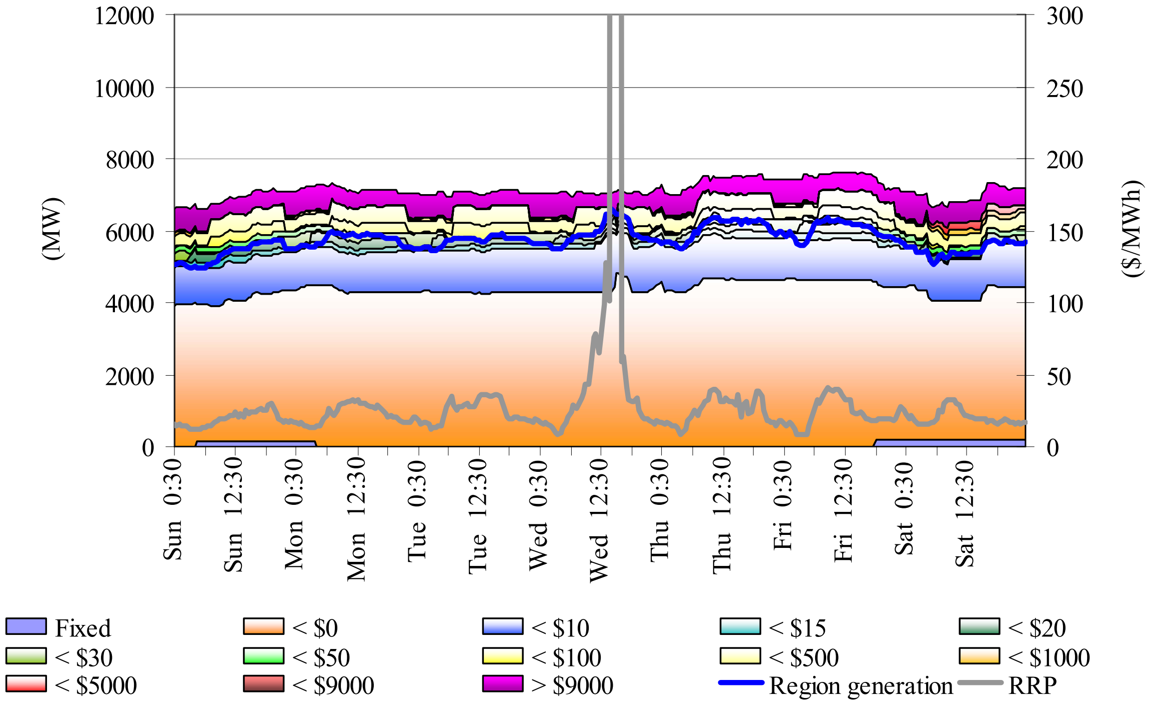


Figure 54: South Australia closing bid prices, dispatched generation and spot price

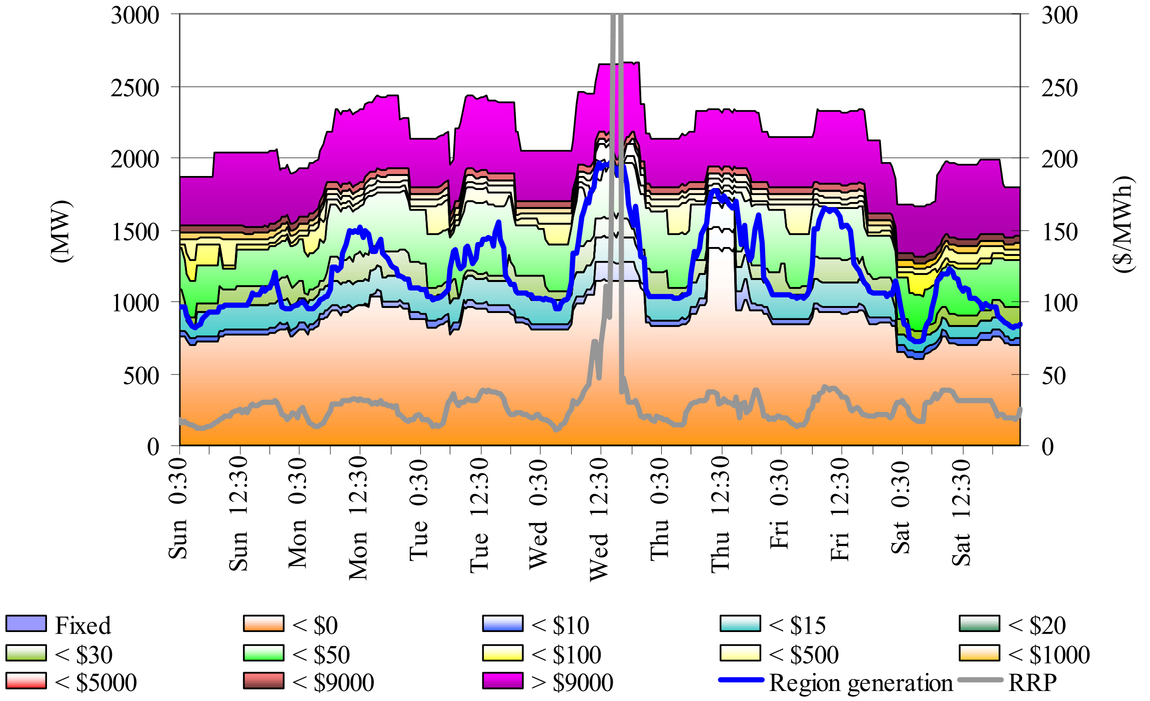
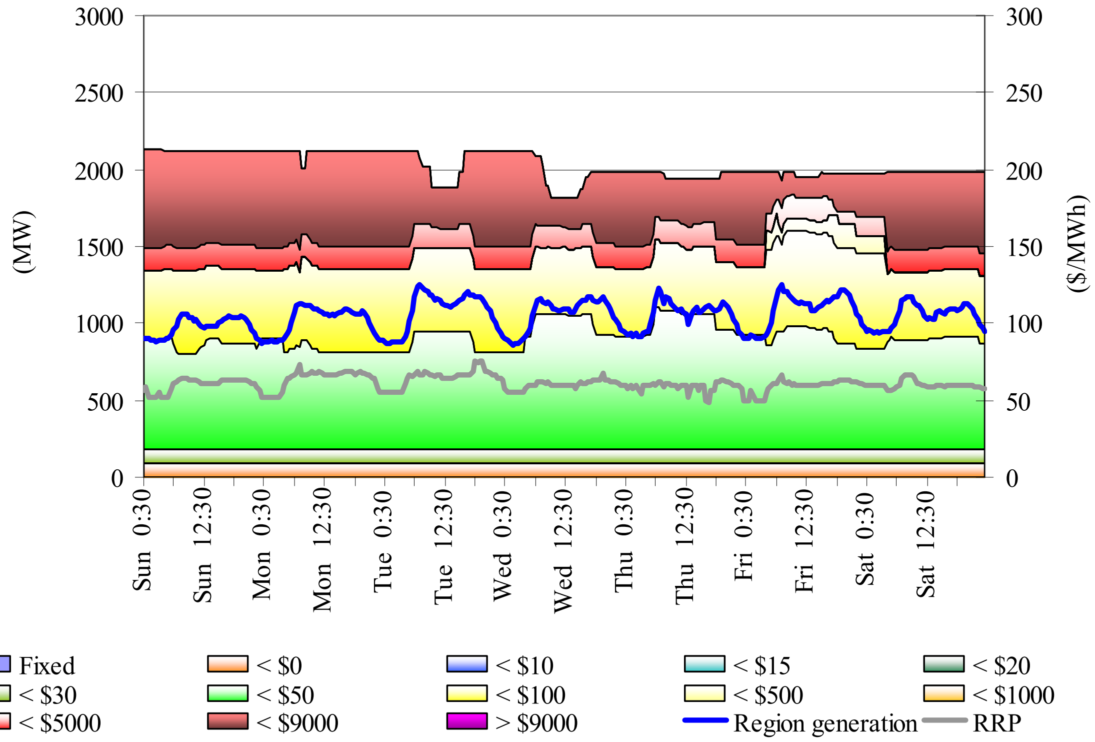


Figure 55: Tasmania closing bid prices, dispatched generation and spot price



Ancillary service market

The total cost of ancillary services on the mainland for the week was around $470 000 or 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	2.61	1.13	1.24	1.81	0.41	2.04	2.03	2.71
Previous week	1.41	0.70	1.14	1.13	0.26	0.31	1.74	2.29
Last quarter	1.62	0.91	1.00	1.36	0.20	0.64	2.29	1.56
Market Cost ($1000s)	$142	$61	$87	$39	$4	$28	$54	$59
% of energy market	0.03%	0.01%	0.02%	0.01%	0.00%	0.01%	0.01%	0.01%

The total cost of ancillary services in Tasmania for the week was around $110 000 or 1 per cent of the total turnover in the energy market in Tasmania. 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	1.06	1.05	1.05	1.05	1.07	1.06	1.06	1.06
Previous week	1.10	1.05	1.05	1.05	1.11	1.05	1.06	1.06
Last quarter	19.40	1.05	1.14	2.25	6.25	1.06	1.06	1.26
Market Cost ($1000s)	8	8	8	9	14	32	26	9
% of energy market	0.07	0.07	0.07	0.08	0.13	0.29	0.24	0.08

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

Figure 58: daily frequency control ancillary service costs

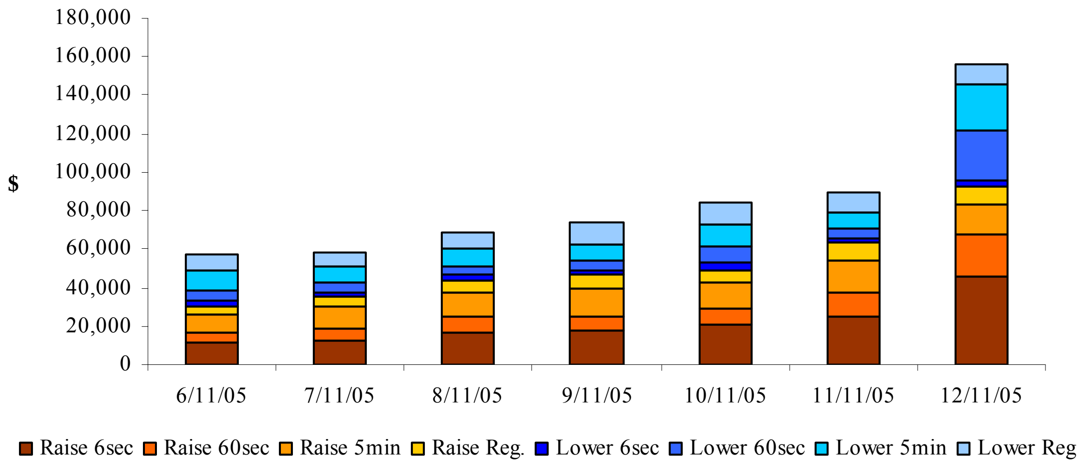
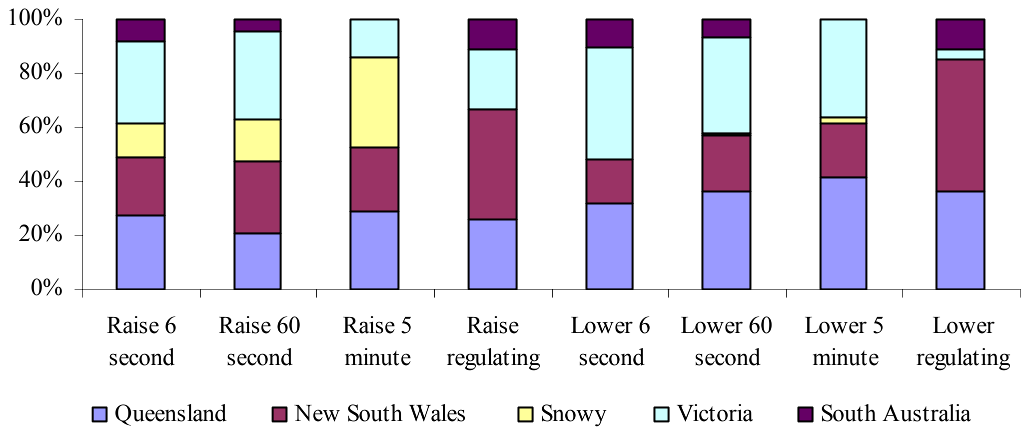


Figure 59 shows the contribution, on a percentage basis, that frequency control ancillary service providers are utilised (in each mainland region) to satisfy the total requirement for each service.

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

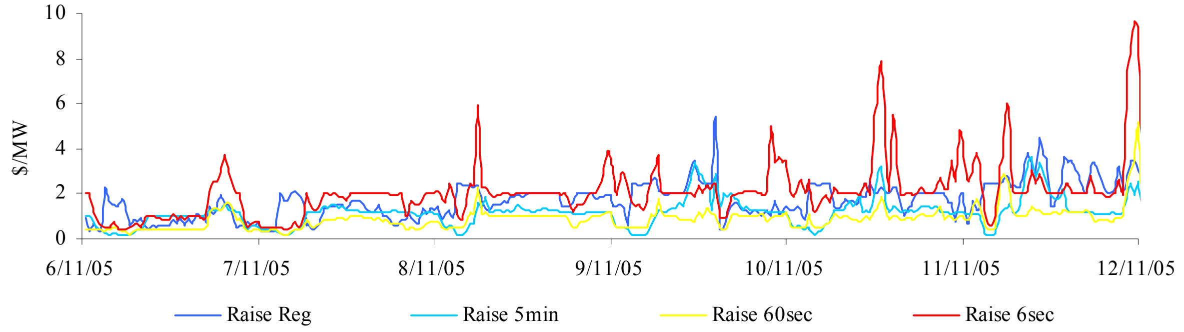


Figure 60A: prices for raise services - Tasmania

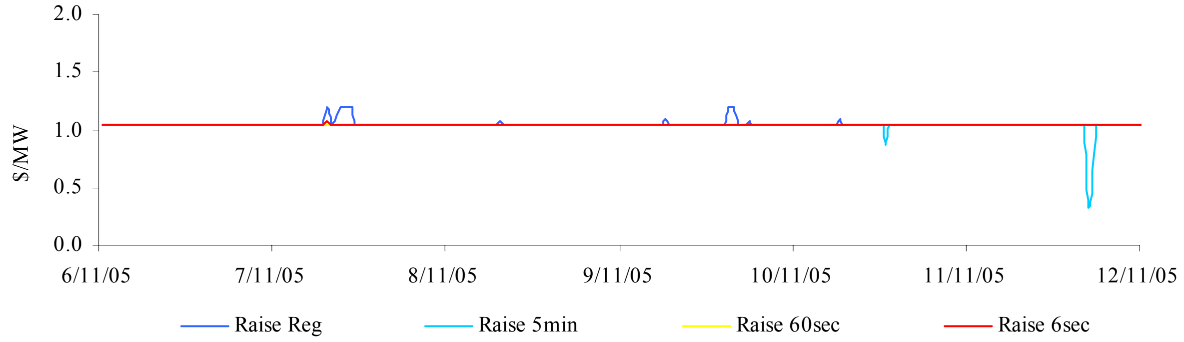


Figure 61: prices for lower services

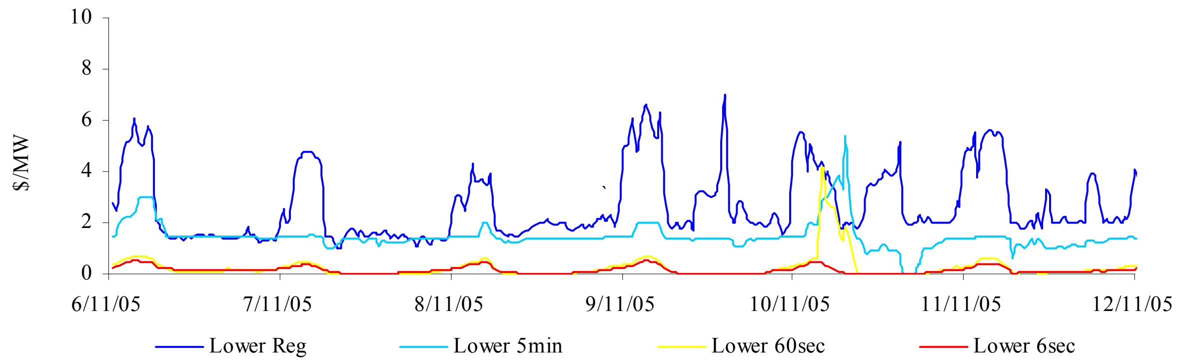
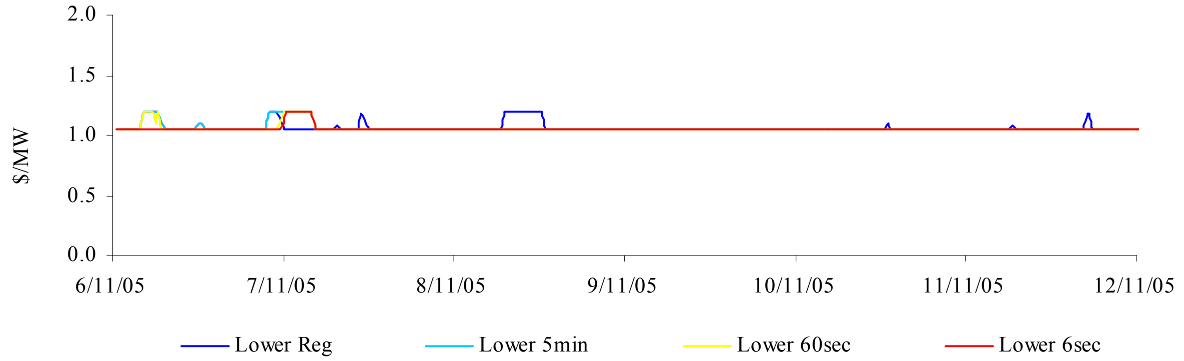


Figure 61A: prices for lower services - Tasmania



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

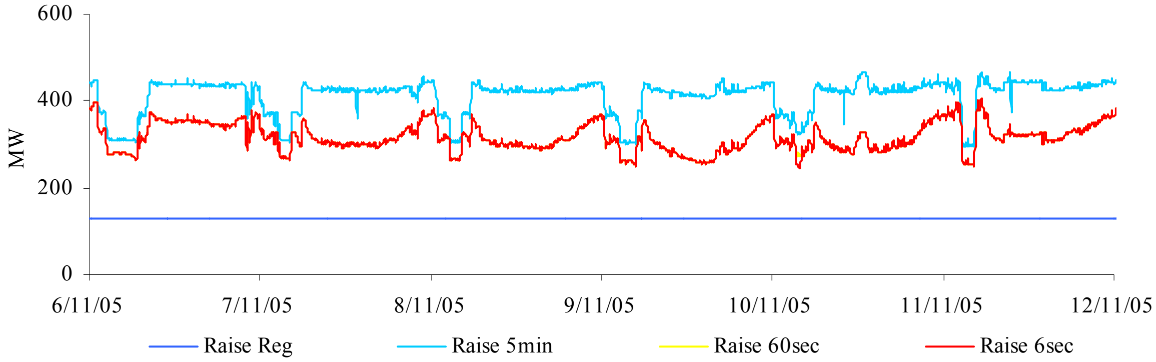


Figure 62A: raise requirements - Tasmania

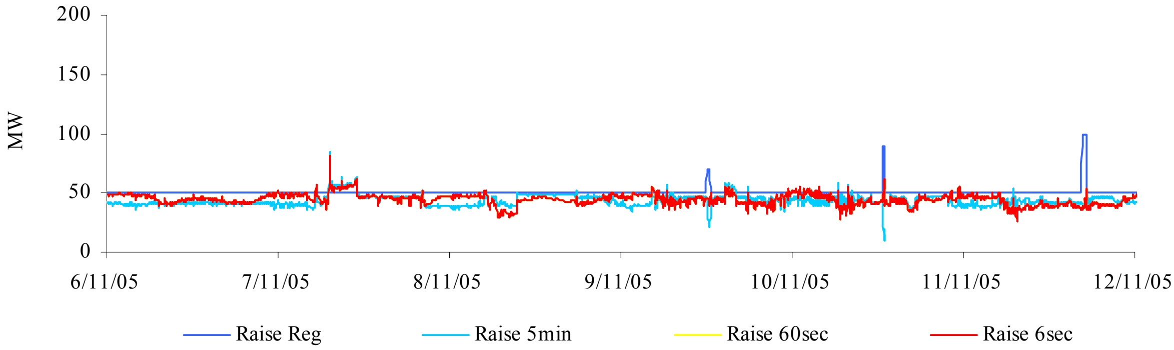


Figure 63: lower requirements

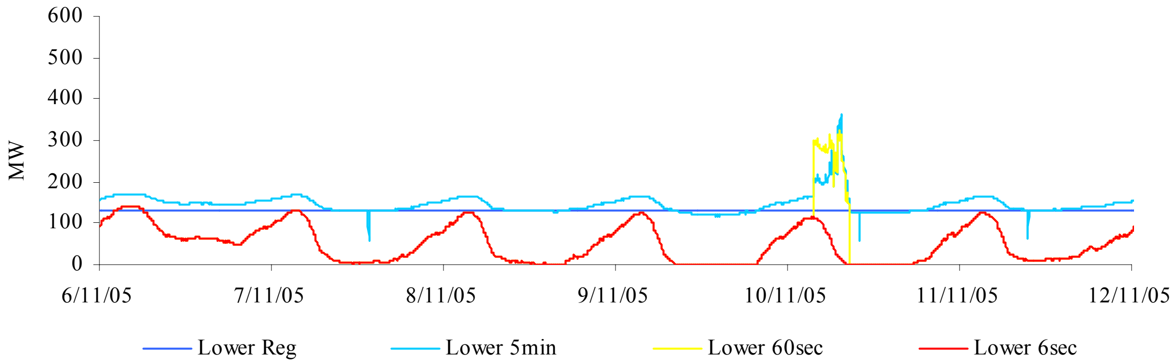
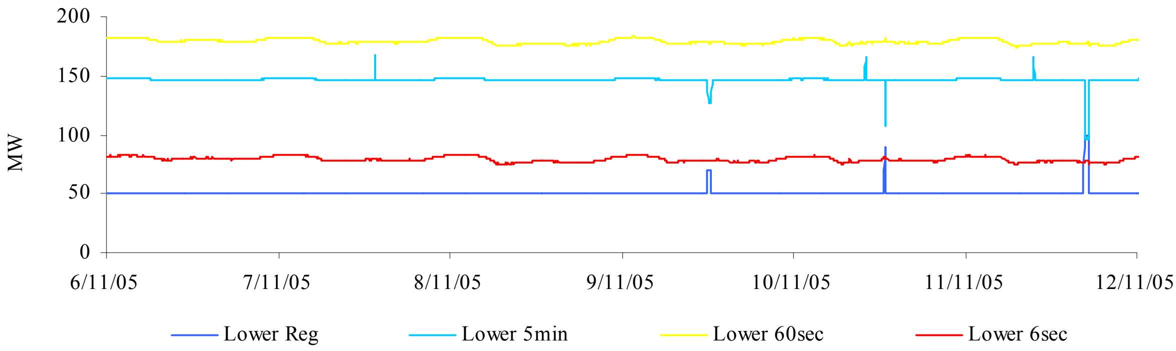


Figure 63A: lower requirements - Tasmania



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