Market analysis

AUSTRALIAN ENERGY REGULATOR

7 – 13 AUGUST 2005

A cold snap late in the week led to new winter record demand in Victoria and Queensland and a near record in New South Wales. Prices averaged $46/MWh in South Australia, $42/MWh in New South Wales and Victoria, and $26/MWh in Queensland. These prices represented an increase of around a quarter compared to the previous week. Flows south into New South Wales continued to average around 900MW reflecting the high level of available capacity in Queensland.

In Tasmania the spot price averaged $170/MWh - a further increase compared to the previous week, to the highest since joining the market. Network constraints on Wednesday evening and Friday morning led to out of merit order despatch at a number of generators. The 5-minute price spiked to $9,000/MWh at 7.25pm on Wednesday and was above $8,000/MWh for 40 minutes on Friday morning.

Turnover in the energy market rose again to around $190 million, while the total cost of ancillary services for the week returned to normal levels at around $450,000 or 0.2 per cent of the total turnover in the energy market.

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 around 40 per cent of all trading intervals in South Australia and Tasmania affected. Significant variations between forecast and actual prices occurred in 108 or a third of all trading intervals, the highest since November last year.

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 2004-05 financial year. 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

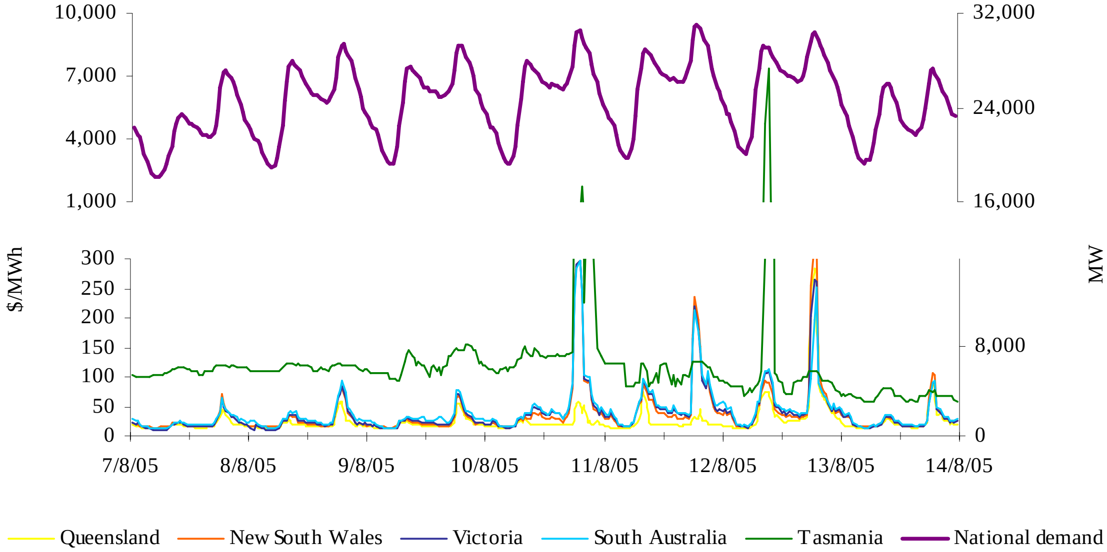


Figure 2: volume weighted average spot price for energy market ($/MWh)

	QLD	NSW	VIC	SA	TAS
Last week	26	42	42	46	170
Previous week	20	32	33	38	149
Same quarter last year	27	31	28	36	-
Financial year 2004 - 05	31	46	29	39	-
% change from previous week	32%	32%	28%	21%	14%
% change from same quarter last year	0%	33%	48%	26%	-
% change from 2003 - 04	-1%	24%	7%	0%	-

Figure 3: volatility index during peak periods

	QLD	NSW	VIC	SA	TAS
Last week	1.77	1.95	1.78	1.59	0.42
Previous week	0.61	1.04	0.93	0.87	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

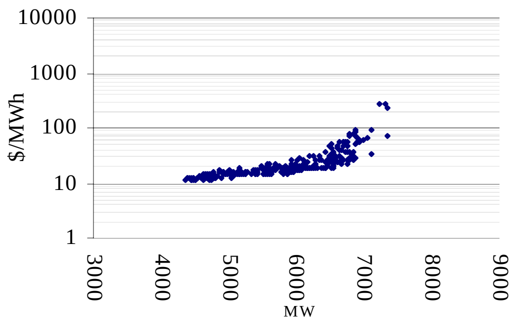


Figure 5: New South Wales

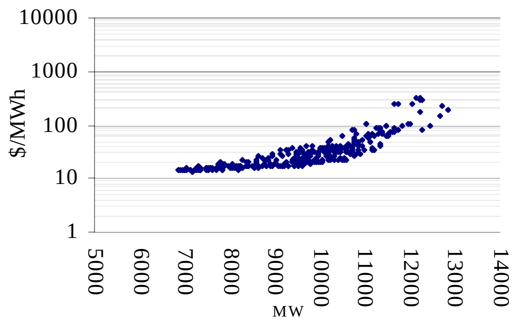


Figure 6: Victoria

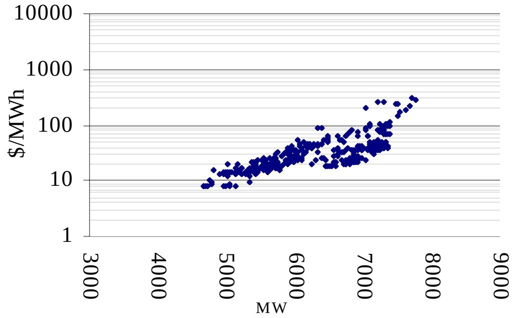


Figure 7: South Australia

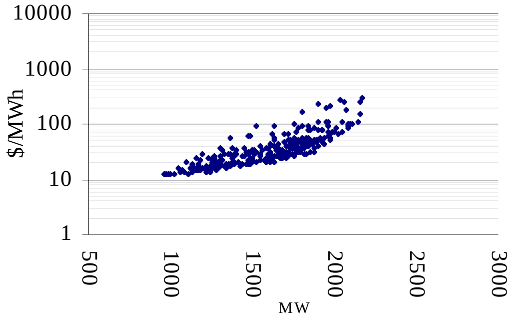
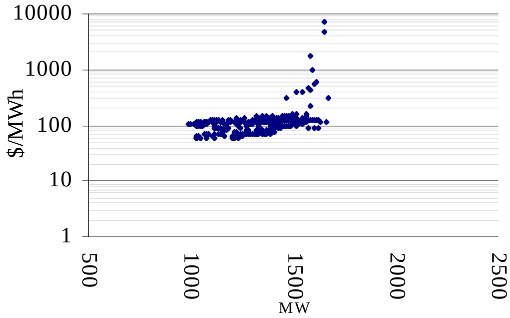


Figure 8: Tasmania



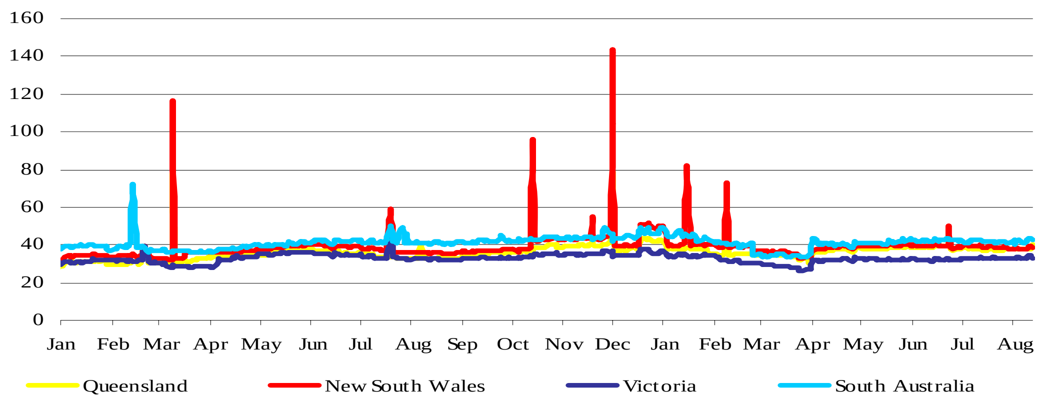
Spot prices peaked at $7,386/MWh in Tasmania on Friday morning. Maximum spot prices in Queensland, New South Wales, Victoria and South Australia were around $300/MWh late in the week.

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	37.80	37.73	37.57	37.62	39.85
New South Wales	37.60	37.61	38.44	39.35	38.31
Victoria	32.55	32.84	34.74	34.12	33.07
South Australia	41.41	41.70	43.70	43.22	42.45

Figure 10: d-cyphaTrade WEPI



Spot prices greater than $5,000/MWh

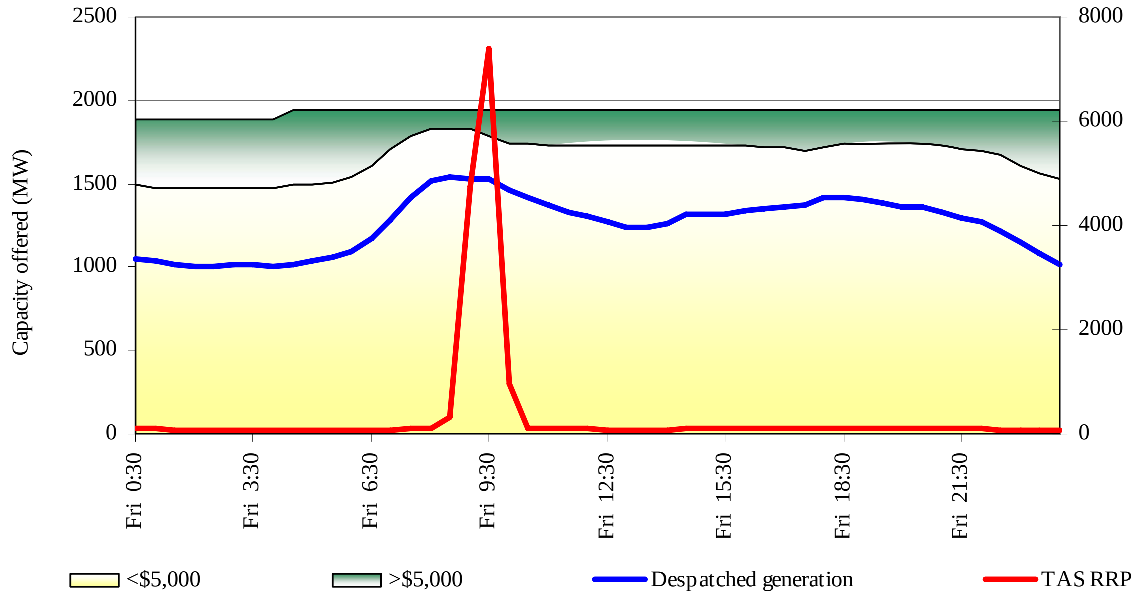
There was one occasion in Tasmania where the spot price was greater than $5,000/MWh. This occurred at 9.30am on Friday. The table below identifies the generating units involved in setting the energy price. Network constraints affected as much as 160MW of lower priced generation, mostly at Gordon.

Friday 12 August – Tasmania price setters for 9.30am

Time	Despatch price	Participant	Unit	Service	Offer price
09:05	$8,986.91	HYDROTAS	TRIBUTE	Raise reg	$1.20
			TRIBUTE	Energy	$8,000.00
			GORDON	Raise reg	$1,000.00
09:10	$8,000.00	HYDROTAS	MACKNTSH	Energy	$8,000.00
			POAT220	Energy	$8,000.00
			LEM_WIL	Energy	$8,000.00
09:15	$9,038.35	HYDROTAS	TUNGATIN	Lower 6 sec	$1.05
			TUNGATIN	Raise 5 min	$1.05
			TUNGATIN	Raise 6 sec	$1.05
			TUNGATIN	Energy	$52.10
			POAT110	Raise 5 min	$1.05
			MEADOWBK	Lower 60 sec	$1.05
			MEADOWBK	Lower 6 sec	$1.05
			MEADOWBK	Raise 60 sec	$1.05
			MEADOWBK	Raise 6 sec	$1.05
			MEADOWBK	Energy	$8,000.00
			MACKNTSH	Lower 6 sec	$1.20
			JBUTTERS	Lower 60 sec	$1.05
			GORDON	Lower 60 sec	$1.05
			GORDON	Raise 60 sec	$1.05
			GORDON	Energy	$71.60
09:20	$9,038.35	HYDROTAS	TUNGATIN	Lower 6 sec	$1.05
			TUNGATIN	Raise 5 min	$1.05
			TUNGATIN	Raise 6 sec	$1.05
			TUNGATIN	Energy	$52.10
			POAT110	Raise 5 min	$1.05
			MEADOWBK	Lower 6 sec	$1.05
			MEADOWBK	Raise 60 sec	$1.05
			MEADOWBK	Raise 6 sec	$1.05
			MEADOWBK	Energy	$8,000.00
			MACKNTSH	Lower 6 sec	$1.20
			GORDON	Raise 60 sec	$1.05
			GORDON	Raise 6 sec	$1.05
			GORDON	Energy	$71.60
09:25	$9,158.68	HYDROTAS	POAT220	Lower 6 sec	$1,000.00
			GORDON	Raise reg	$1,000.00
			BASTYAN	Lower 6 sec	$1.20
			BASTYAN	Raise reg	$1.20
			BASTYAN	Energy	$8,000.00
09:30	$94.71	HYDROTAS	REECE2	Lower 5 min	$1.05
			JBUTTERS	Raise 6 sec	$1.05
			GORDON	Lower 5 min	$1.05
			GORDON	Raise 6 sec	$1.05
			GORDON	Energy	$94.71
Spot price	**$7,386.17**				

The figure below presents, for Friday 12 August, the capacity offered by Hydro Tasmania at prices less than and greater than $5,000/MWh.

Friday 12 August - Hydro Tasmania closing bid prices and despatched generation



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

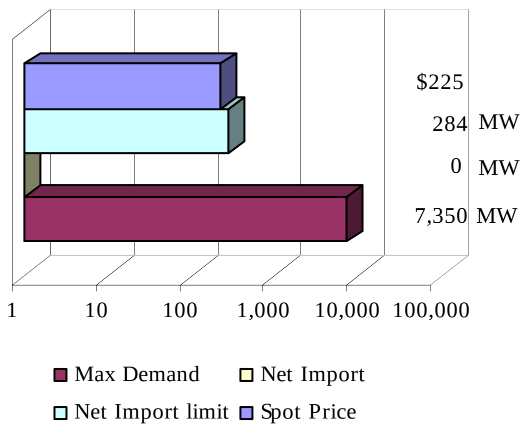


Figure 12: New South Wales

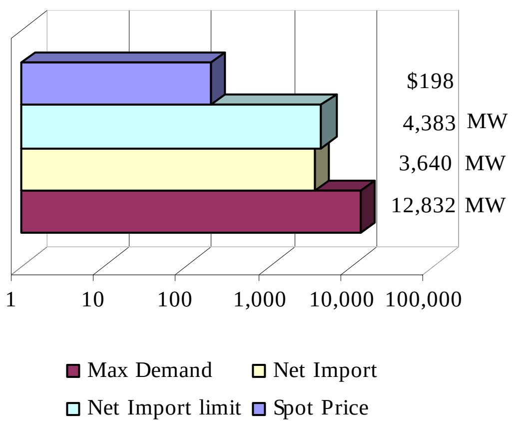


Figure 13: Victoria

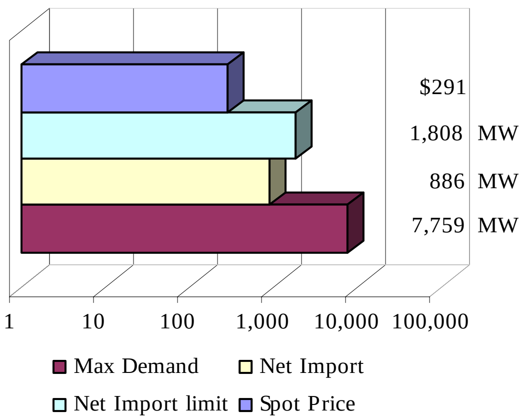
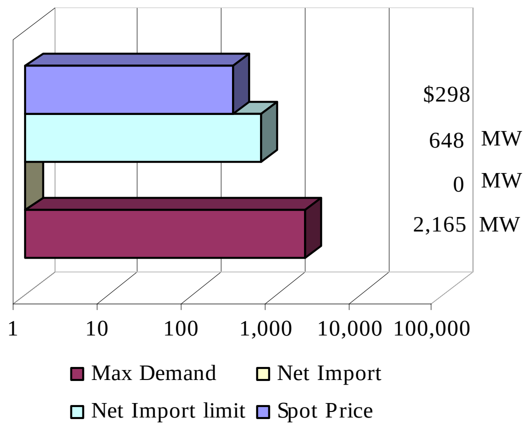


Figure 14: South Australia



In Tasmania, the demand reached a maximum of 1,668MW at 8.30am on Friday morning. The spot price at the time was $305/MWh.

Price variations

There were 108 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

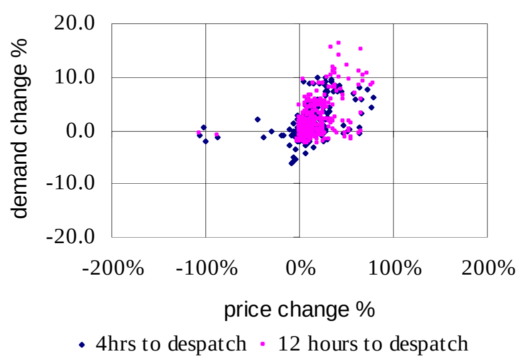


Figure 16: New South Wales

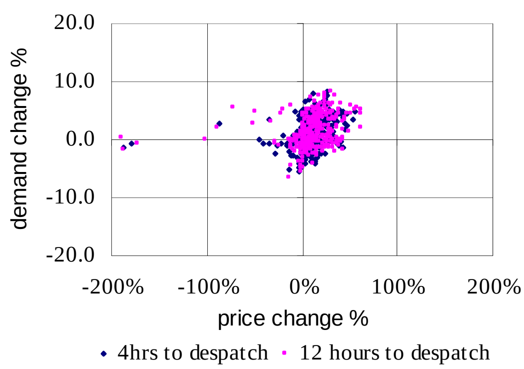


Figure 17: Victoria

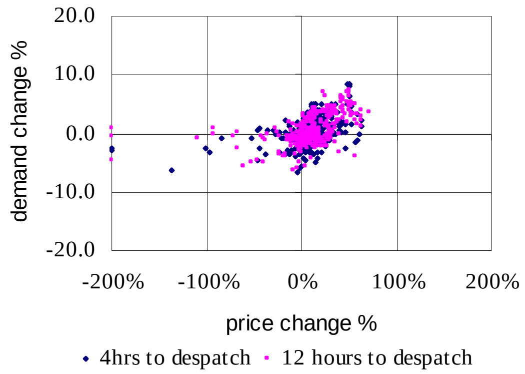


Figure 18: South Australia

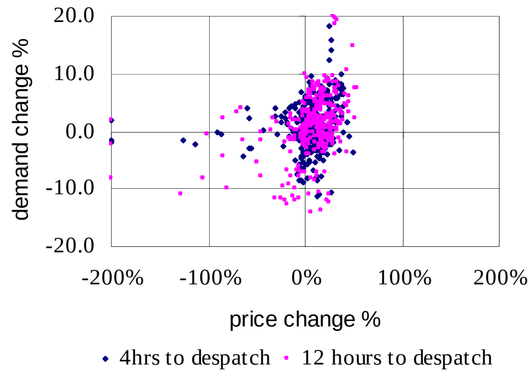


Figure 19: Tasmania

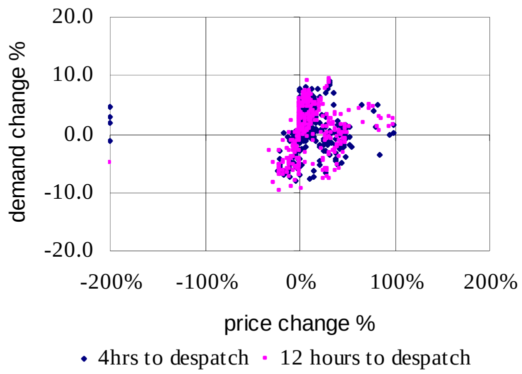
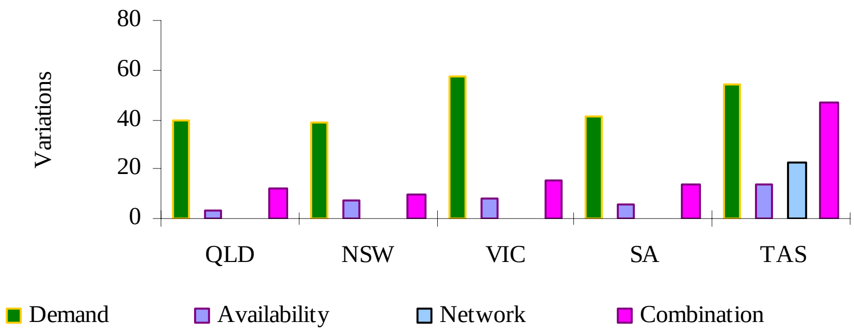


Figure 20 summarises the number and most probable reason for variations between forecast and actual prices.

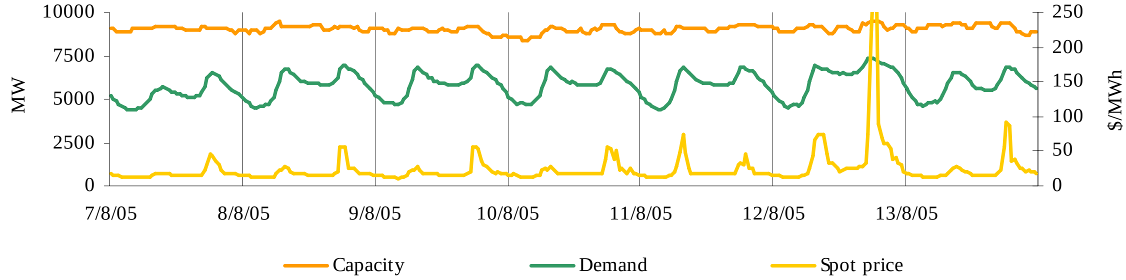
Figure 20: reasons for variations between forecast and actual prices

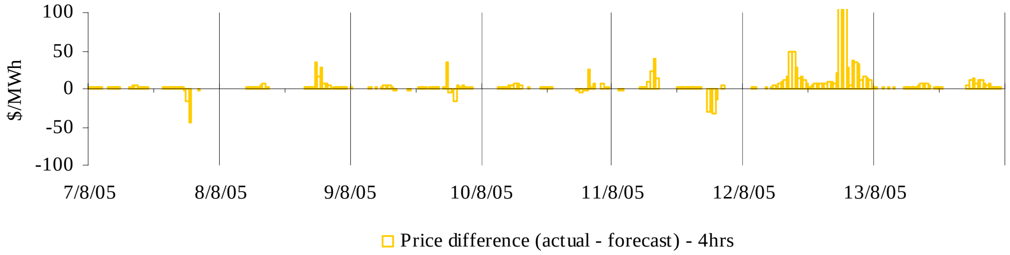


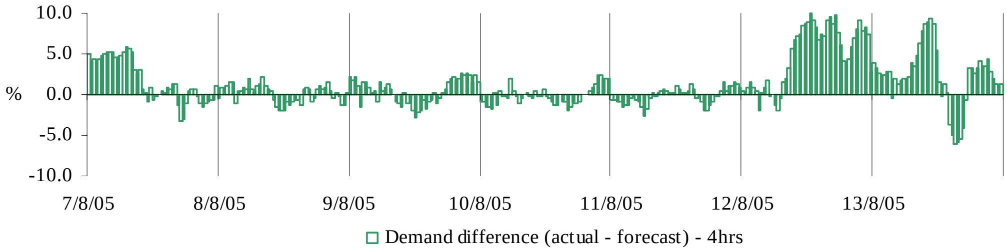
Price and demand

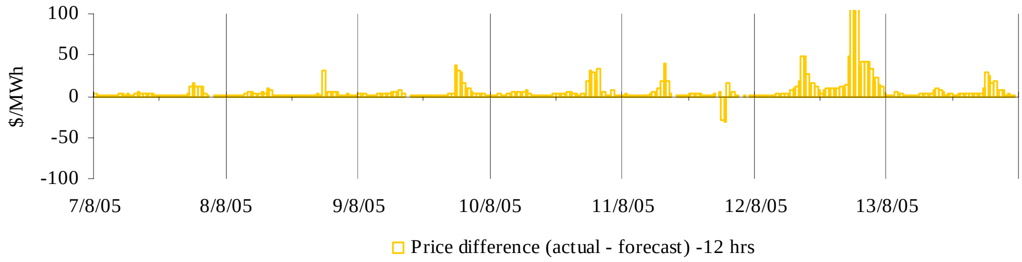
Figures 21 - 50 set out details of spot prices and demand on a regional basis. They include the actual spot price and demand outcomes and difference graphs both four and twelve hours ahead of despatch on a daily basis. The differences between the maximum temperature and the temperature forecast at around 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.

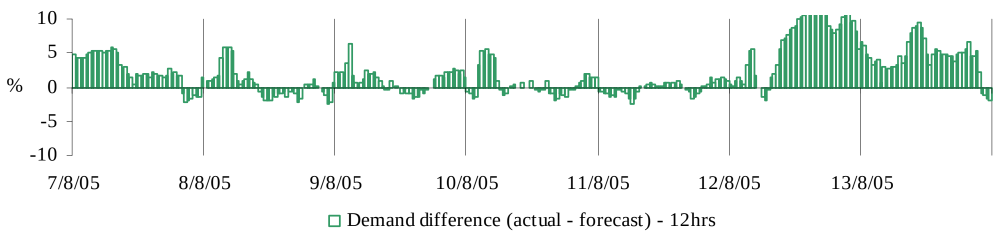
Figures 21-26: Queensland actual spot price, demand and forecast differences

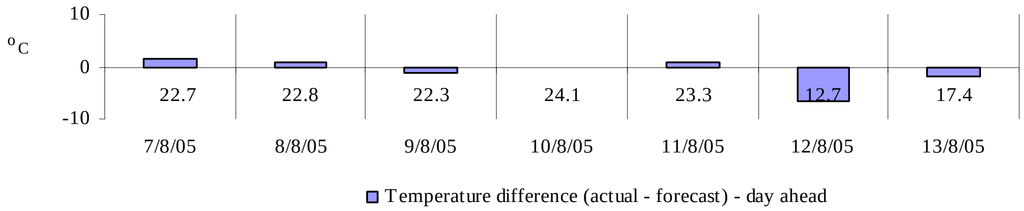












There were 6 occasions in Queensland where the spot price was greater than three times the weekly average price of $26/MWh. These occurred between 6pm and 7.30pm on Friday and at 6.30pm and 7pm on Saturday.

Friday, 12 August

6:00 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	224.97	60.61	60.61
Demand (MW)	7,350	6,788	6,571
Available capacity (MW)	9,460	9,426	9,431
6:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	284.13	60.61	60.61
Demand (MW)	7,308	6,861	6,660
Available capacity (MW)	9,458	9,441	9,446
7:00 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	268.90	62.61	60.61
Demand (MW)	7,240	6,938	6,634
Available capacity (MW)	9,505	9,441	9,446
7:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	88.61	60.73	54.00
Demand (MW)	7,106	6,853	6,535
Available capacity (MW)	9,507	9,441	9,446

Conditions at the time saw demand at record high winter levels, around 600MW higher than the four hour ahead forecast and almost 800MW higher than the 12 hour ahead forecast. The maximum temperature in Brisbane reached only 12.7 degrees, the coldest day for at least 6 years. Prices were aligned with New South Wales.

Intra-regional constraints affected up to 330MW of generation in central Queensland. These constraints were not forecast. This resulted in Enertrade, at 5.28pm and 5.37pm, repricing all of its capacity at Gladstone to zero. This included 270MW of capacity priced at $60/MWh. The rebid reason given was “NEMMCO constraint::change MW distrib”. Earlier, at 4.28pm, Enertrade had rebid 45MW of capacity at Mt Stuart from the price cap to zero, committing a unit,and 36MW from prices around $100/MWh to zero at Collinsville. The rebid reasons given were “Amended constraint position Change MW distrib” and “Material change in market conditions::Changed MW distrib” respectively.

At 3.30pm, Origin Energy committed both Roma units, rebidding a total of 70MW from prices of $9,000/MWh to $1/MWh. The rebid reason given was “Est (NP) change in PDS and handover bid”.

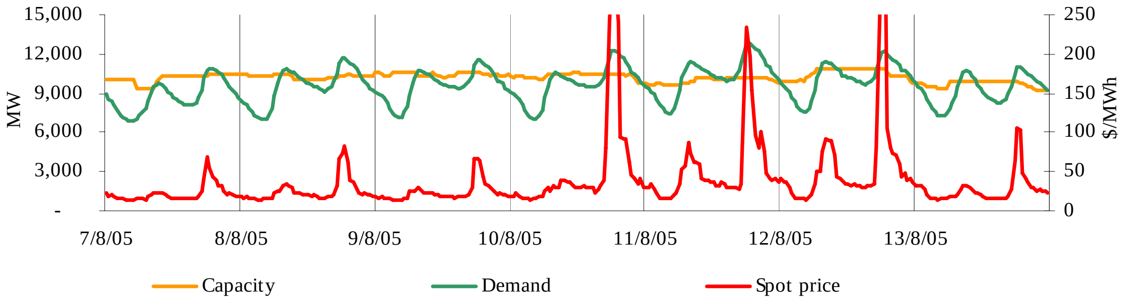
CS Energy made a number of bids close to despatch. At 3.31pm, a rebid moved 55MW of capacity at Swanbank E from prices of less than $50/MWh to prices greater than $100/MWh. The rebid reason given was “Swan E balancing gas”. At 5.06pm and 5.28pm, rebids increased the availability of units 3 and 1 at Swanbank B respectively by a total of 50MW. Most of this capacity was priced at less than $50/MWh. There was no other significant rebidding.

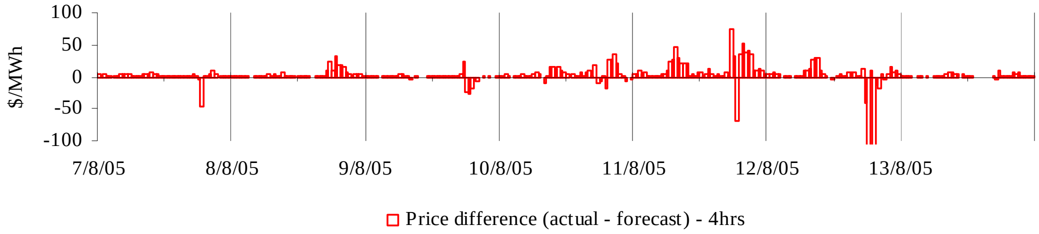
Saturday, 13 August

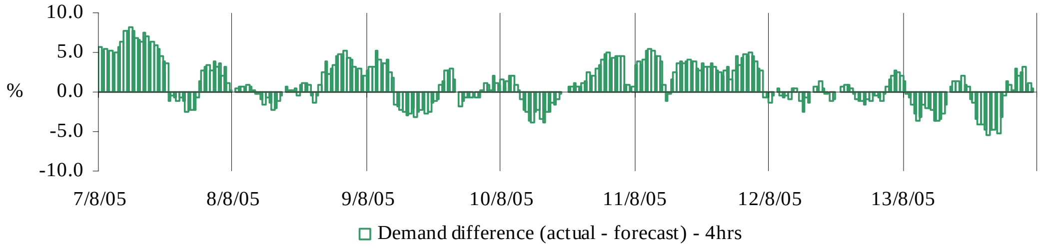
6:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	90.65	77.83	62.64
Demand (MW)	6,886	6,666	6,533
Available capacity (MW)	9,357	9,357	9,359
7:00 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	87.69	79.95	62.64
Demand (MW)	6,872	6,692	6,528
Available capacity (MW)	9,359	9,357	9,359

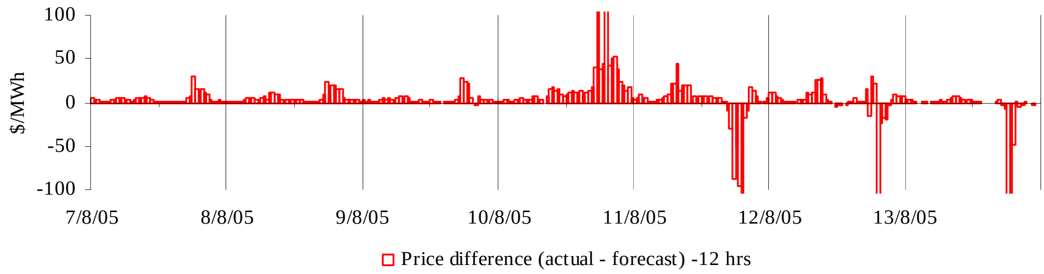
Conditions at the time saw demand around 200MW higher than the four hour ahead forecast and around 350MW higher than the 12 hour ahead forecast. There was no significant rebidding.

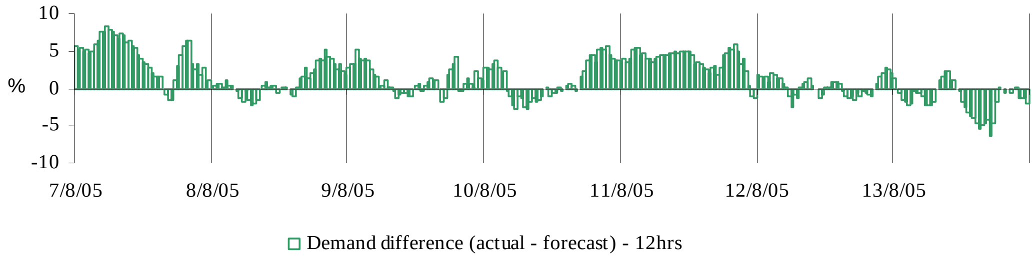
Figures 27-32 New South Wales actual spot price, demand and forecast differences

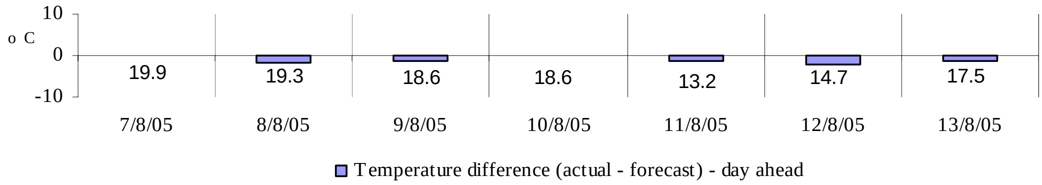












There were 11 occasions in New South Wales where the spot price was greater than three times the weekly average price of $42/MWh. These occurred during the evening peak on Wednesday, Thursday and Friday.

Wednesday, 10 August

6:00 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	241.40	250.53	90.02
Demand (MW)	11,669	11,282	11,412
Available capacity (MW)	10,458	10,525	10,595
6:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	290.29	297.50	252.01
Demand (MW)	12,205	11,705	11,745
Available capacity (MW)	10,445	10,525	10,595
7:00 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	295.74	293.72	252.43
Demand (MW)	12,291	11,690	11,741
Available capacity (MW)	10,445	10,525	10,595
7:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	241.49	258.54	90.89
Demand (MW)	12,059	11,469	11,526
Available capacity (MW)	10,445	10,525	10,595

Conditions at the time saw demand up to 600MW higher than that forecast four hours to despatch. Prices were close to forecast and were aligned across the southern regions. At 3.59pm and 4.52pm, Macquarie Generation rebid as much as 550MW of capacity across its Bayswater and Liddell units from prices of more than $800/MWh to prices around $250/MWh. The rebid reasons given were “RP/Volume tradeoff – NEMMCO load forecast increased” and “RP/Volume tradeoff – load expected to vary from forecast”. Earlier in the day, 480MW of this capacity had been priced at less than $20/MWh.

Delta Electricity reduced the availability of Vales Point unit 5 over a number of rebids throughout the day, resulting in a reduction of as much as 160MW for the period. All of this capacity was priced at less than $20/MWh. There was no other significant rebidding.

Thursday, 11 August

6:00 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	172.18	96.17	259.71
Demand (MW)	12,210	11,864	11,860
Available capacity (MW)	10,133	10,233	10,430
6:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	234.52	203.36	287.88
Demand (MW)	12,730	12,152	12,149
Available capacity (MW)	10,133	10,433	10,430
7:00 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	197.94	266.33	294.02
Demand (MW)	12,832	12,389	12,229
Available capacity (MW)	10,163	10,463	10,430
7:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	152.65	116.47	262.94
Demand (MW)	12,648	12,105	11,962
Available capacity (MW)	10,163	10,193	10,430

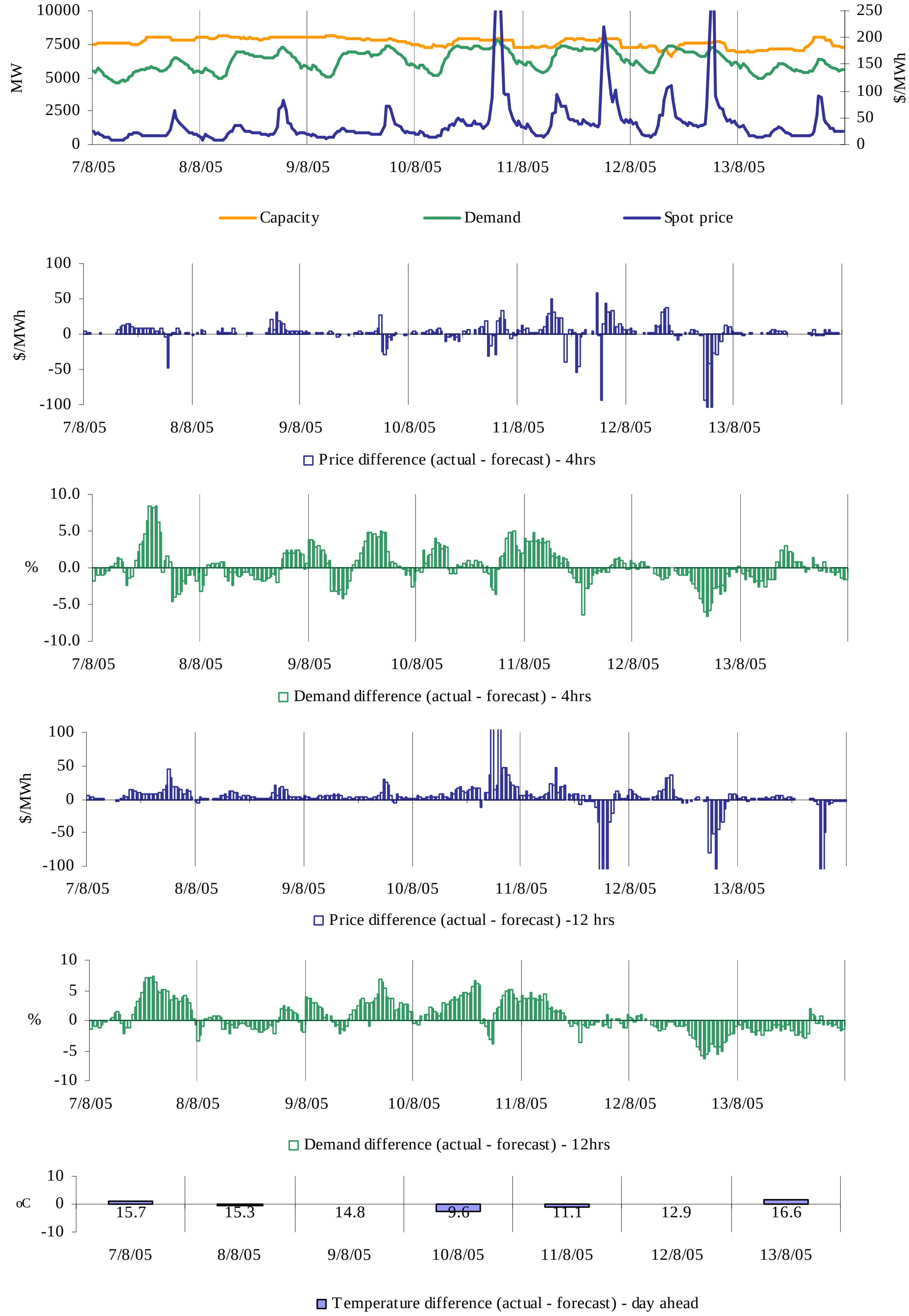
Conditions at the time saw demand as much as 600MW higher than forecast and at near record levels. Prices were aligned across the southern regions as forecast. There was no significant rebidding.

Friday, 12 August

6:00 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	253.74	294.22	268.44
Demand (MW)	11,723	11,828	11,808
Available capacity (MW)	10,869	10,949	10,946
6:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	330.55	949.49	299.69
Demand (MW)	12,133	12,284	12,271
Available capacity (MW)	10,869	10,949	10,946
7:00 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	322.56	311.47	299.92
Demand (MW)	12,217	12,262	12,262
Available capacity (MW)	10,857	10,949	10,946

Conditions at the time saw demand slightly lower than the four hour ahead forecast, with prices close to forecast or lower and aligned across the southern regions. At 4.55pm, Macquarie Generation rebid 400MW at Bayswater from prices of $15/MWh to prices above $900/MWh, and rebid 270MW at Liddell from prices of less than $100/MWh to prices above $6,500/MWh. The rebid reason given was “RP/Volume tradeoff – load expected to vary from forecast”. There was no other significant rebidding.

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



There were 11 occasions in Victoria where the spot price was greater than three times the weekly average price of $42/MWh. These occurred during the evening peak on Wednesday, Thursday and Friday.

Wednesday, 10 August

6:00 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	238.88	270.62	103.77
Demand (MW)	7,486	7,757	7,784
Available capacity (MW)	7,891	7,908	8,033
6:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	290.71	307.22	276.00
Demand (MW)	7,759	7,771	7,672
Available capacity (MW)	7,903	7,903	7,983
7:00 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	296.67	299.39	276.00
Demand (MW)	7,701	7,593	7,542
Available capacity (MW)	7,903	7,903	7,990
7:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	241.10	270.62	103.22
Demand (MW)	7,516	7,393	7,355
Available capacity (MW)	7,789	7,791	7,818

Conditions at the time saw price and demand close to forecast and at record winter levels. Prices were aligned across the southern regions. International Power committed four Valley Power units over the course of the day. The rebids, made at 2.56pm, 2.59pm, 3.29pm and 5.09pm, moved a total of 230MW of capacity from prices around $400/MWh to zero. The rebid reason given was “Change in price forecasts”. At 5.06pm, Ecogen rebid a total of 50MW from prices above $9,000/MWh to $300/MWh and $150/MWh. The rebid reason given was “Band adj due to market cond::Price vol tradeoff”. There was no other significant rebidding.

Thursday, 11 August

6:00 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	165.48	106.40	276.00
Demand (MW)	7,530	7,546	7,523
Available capacity (MW)	7,921	7,896	7,928
6:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	218.95	220.44	306.71
Demand (MW)	7,697	7,741	7,767
Available capacity (MW)	7,923	7,896	7,901
7:00 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	182.03	276.00	311.25
Demand (MW)	7,628	7,680	7,680
Available capacity (MW)	7,930	7,886	7,901
7:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	142.50	128.18	276.00
Demand (MW)	7,508	7,486	7,441
Available capacity (MW)	7,933	7,896	7,911

Conditions at the time saw price and demand close to forecast and at near record winter levels. Prices were aligned across the southern regions. International Power committed all six Valley Power units for the evening peak through rebids made during the afternoon. These rebids, made from 2pm, moved as much as 350MW of capacity, mostly from prices of around $400/MWh to zero. The rebid reasons given were "Change in demand forecasts", "Change in unit startup sequence", "Change in price forecasts" and "Changing plant conditions".

Ecogen rebid 50MW at Newport over a number of rebids close to despatch from prices above $9,000/MWh to prices of $90/MWh and $150/MWh. The rebid reasons given were "Adj to unit commitment due to PD conditions" and "Adj to unit commitment schedule due to PD conditions".

AGL rebid as much as 78MW at Somerton close to despatch from prices above $9,000/MWh to zero, committing the unit. 28MW was returned to high prices during the 6.30pm trading interval. 20MW was shifted back to zero during the 7pm trading interval. The rebid reasons given were "Predispatch:forecast price increase::5min", "Capacity adjustment due to ambient temperature", "Financial optimisation" and "Financial optimisation:5min price outlook".

Southern Hydro rebid 141MW across McKay and Dartmouth from prices around $300/MWh to prices around $100/MWh close to despatch. The rebid reasons given were "Optimise AS and energy::decrease energyband".

There was no other significant rebidding.

Friday, 12 August

6:00 pm	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	203.71	296.43	283.36
Demand (MW)	7,052	7,384	7,408
Available capacity (MW)	7,643	7,624	7,108
6:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	266.06	929.82	313.42
Demand (MW)	7,290	7,501	7,580
Available capacity (MW)	7,637	7,629	7,103
7:00 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	260.39	301.18	311.61
Demand (MW)	7,209	7,413	7,485
Available capacity (MW)	7,640	7,629	7,078

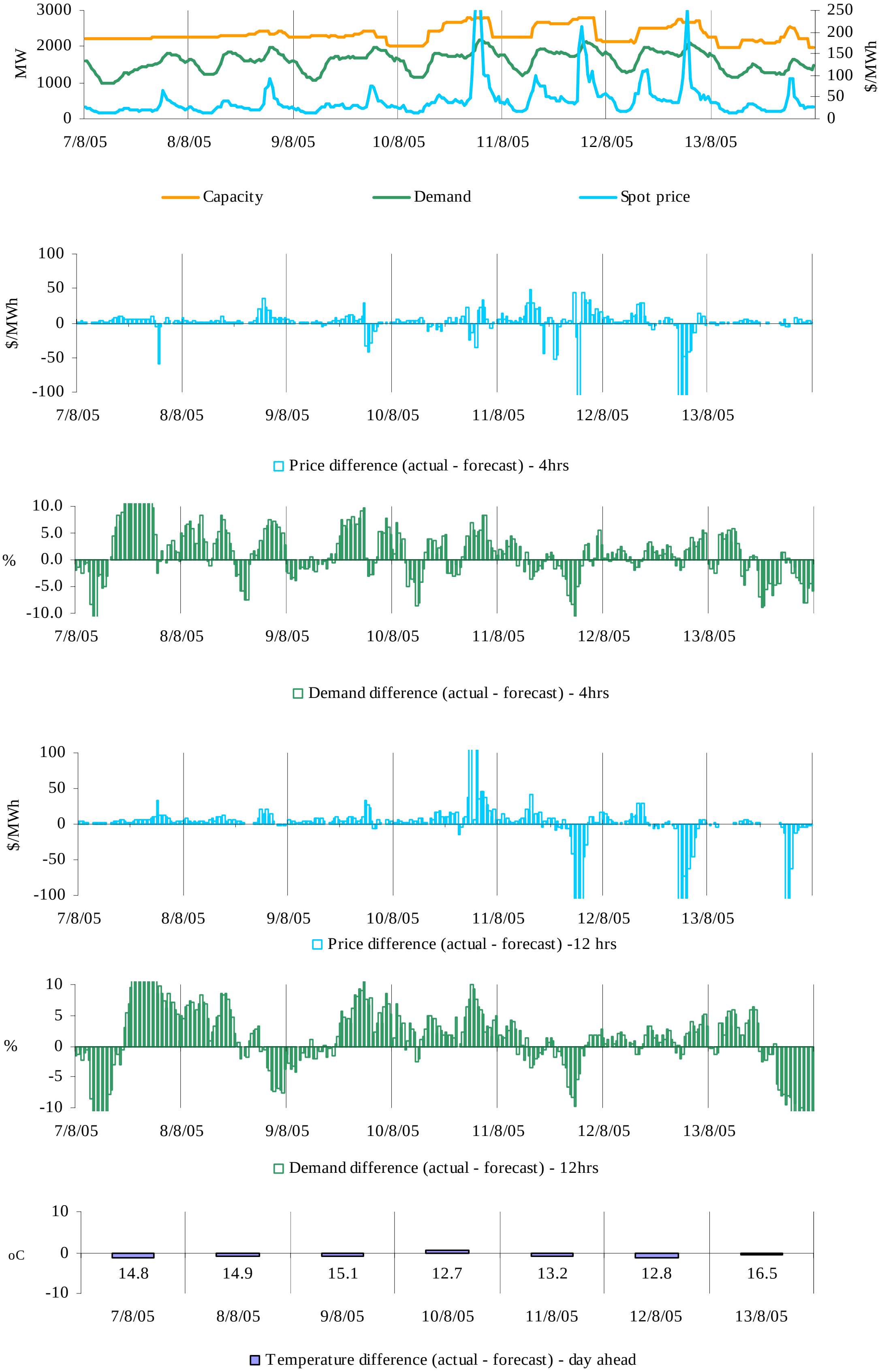
Conditions at the time saw demand as much as 300MW lower than forecast at the beginning of this period. Prices were aligned across the southern regions and generally lower than forecast.

Ecogen committed 685MW of capacity across Jeeralang and Newport, some close to despatch. At 4.13pm and 5.11pm, a total of 405MW of capacity at Newport was moved from prices above $9,000/MWh to prices below $50/MWh. The rebid reasons given were ‘Adj to unit commitment due to PD conditions’ and “Adj to bands due to NEMMCO data probs contr risk man”. At around 5.10pm, 280MW was moved from prices above $9,000/MWh to prices below $150/MWh across Jeeralang A and B. The rebid reason given was “Adj to bands due to NEMMCO data probs contr risk man”.

Over a number of rebids, close to despatch, AGL moved as much as 110MW of capacity at Somerton from prices above $9,000/MWh to zero. The rebid reason given was ‘Predispatch::forecast price increase::5min”.

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 $46/MWh. These occurred during the evening peak on Wednesday, Thursday and Friday.

Wednesday, 10 August

6:00 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	233.51	258.33	109.48
Demand (MW)	1,896	1,819	1,755
Available capacity (MW)	2,772	2,785	2,755
6:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	283.88	298.01	283.45
Demand (MW)	2,042	1,902	1,837
Available capacity (MW)	2,790	2,785	2,755
7:00 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	298.38	299.00	291.98
Demand (MW)	2,165	2,042	1,963
Available capacity (MW)	2,790	2,785	2,755
7:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	243.03	278.55	118.07
Demand (MW)	2,164	2,070	2,000
Available capacity (MW)	2,745	2,610	2,588

Conditions at the time saw demand around 100MW higher than forecast four hours to despatch, with prices as forecast and aligned across the southern regions. South Australia was exporting as much as 200MW to Victoria during this period.

At 11.12am, Origin Energy committed all four Quarantine units, effective immediately. The units operated for the rest of the day. The rebid reason given were "Est (N) change in PDS".

From 4.43pm, TRU Energy made a number of bids, which moved as much as 100MW from prices above $300/MWh to prices of $150/MWh or less. The rebid reasons given were "Plant and Mrkt conditions – redist of MW across units", "Market conditions – price/vol tradeoff" and "Market conditions – gen resp to pd conditions'.

AGL committed Hallet at 5.28pm, with a rebid which moved 50MW of capacity from prices above $9,000/MWh to zero. A number of rebids extended the units commitment, at around this level, until 9.30pm. The rebid reasons given included "Predispatch:forcast price increase:increa".

At 5.45pm, International Power increased the availability at Pelican Point by 30MW, and priced this capacity at $148/MWh. The rebid reason given was 'Recently advised plant condition change".

There was no other significant rebidding.

Thursday, 11 August

6:00 pm	Actual	4 hr forecast	12 hr forecast
Price ($/MWh)	162.50	119.22	293.43
Demand (MW)	1,804	1,993	1,981
Available capacity (MW)	2,785	2,755	2,750
6:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	211.54	231.87	317.62
Demand (MW)	1,974	2,072	2,080
Available capacity (MW)	2,794	2,755	2,750
7:00 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	178.77	293.07	330.50
Demand (MW)	2,078	2,168	2,169
Available capacity (MW)	2,797	2,785	2,750
7:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	148.83	148.00	299.00
Demand (MW)	2,156	2,177	2,166
Available capacity (MW)	2,797	2,785	2,567

Conditions at the time saw demand almost 200MW lower than forecast at the beginning of the period. Prices were aligned across the southern regions and close to forecast. South Australia was exporting as much as 250MW to Victoria during this period.

Close to despatch, TRU Energy rebid as much as 210MW of capacity at Torrens Island from prices of $300/MWh or more to prices of $150/MWh. The rebid reason given was “Market conditions-Gen response to PD conditions”.

International Power increased the availability at Pelican Point by as much as 45MW over two rebids at 2.12pm and 6.08pm. This capacity was priced at less than $150/MWh. The rebid reason given was “Recently advised plant condition change”.

AGL committed as much as 70MW at Hallet during this period, moving this capacity from prices above $9,000/MWh to zero. The rebid reasons given included “Predispatch:forecast price increase 5min”. and “Predispatch:interconnector constraint::5mi”.

There was no other significant rebidding.

Friday, 12 August

6:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	197.31	928.88	322.31
Demand (MW)	1,949	1,977	1,977
Available capacity (MW)	2,659	2,764	2,694
7:00 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	252.72	300.67	325.98
Demand (MW)	2,066	2,030	2,032
Available capacity (MW)	2,668	2,764	2,694

Conditions at the time saw demand close to forecast. South Australia was exporting at up to the limit of around 320MW to Victoria between 5.30pm and 6.30pm. Prices were aligned across the southern regions during the 7pm trading interval.

Origin Energy committed two Quarantine units at 3.30pm. The rebid reason given was 'Est (N) Change in PDS and handover bid".

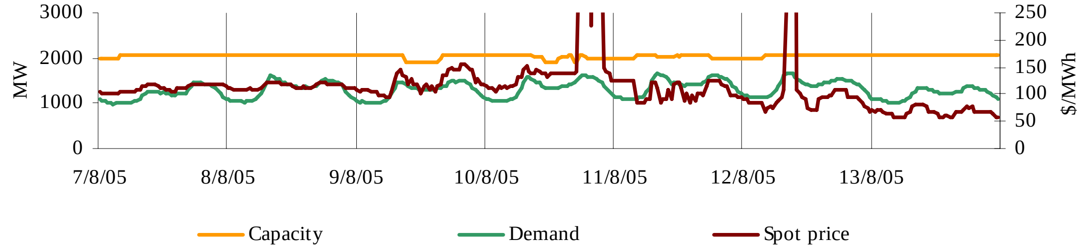
Close to despatch, TRU Energy rebid as much as 220MW of capacity at Torrens Island from prices above $9,000/MWh to prices of $150/MWh and $300/MWh. The rebid reason given was "Market conditions-Gen response to PD conditions". At 5.55pm, 80MW was moved from prices of less than $55/MWh to $299/MWh. The rebid reason given was "Price/volume tradeoff".

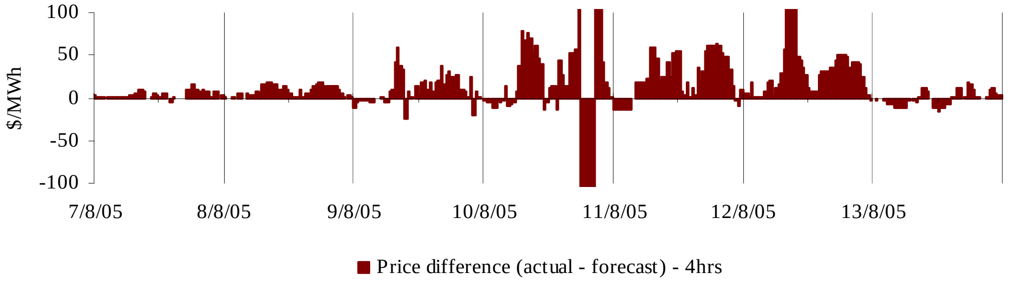
At 5.27pm, AGL rebid 100MW of capacity at Hallet from prices above $9,000/MWh to zero. At 6.34pm, a further 40MW was moved from above $9,000/MWh to zero. The rebid reason given on each occasion was "Predispatch::Forecast price increase::increa".

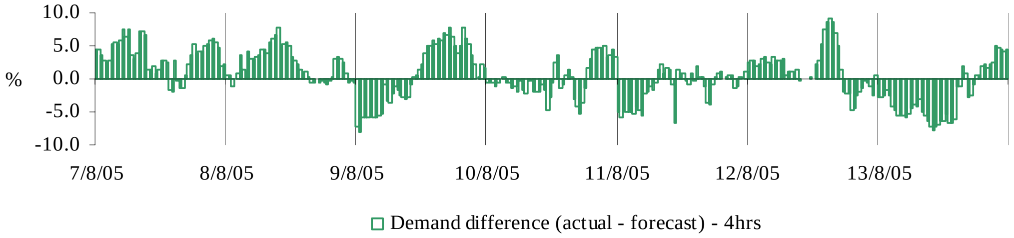
International Power rebid 50MW at Dry Creek from prices above $700/MWh to zero over a number of rebid close to despatch. The rebid reasons given were "Replace trip Mintaro", "Recently advised plant condition change".

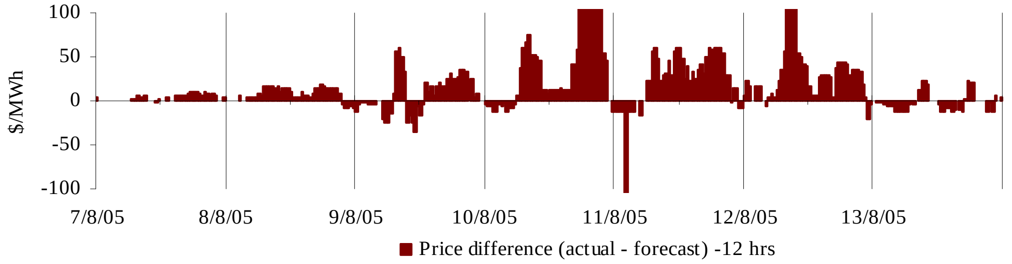
There was no other significant rebidding.

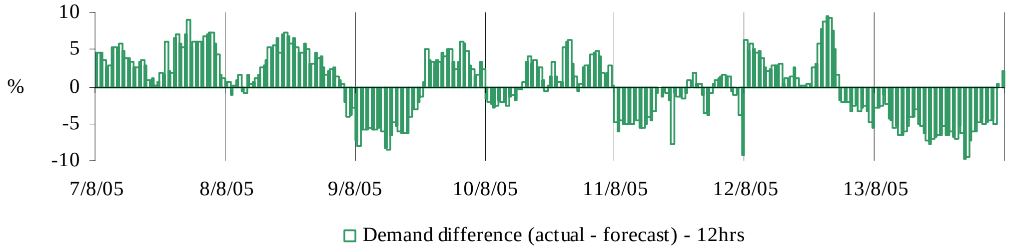
Figures 45-50: Tasmania actual spot price, demand and forecast differences

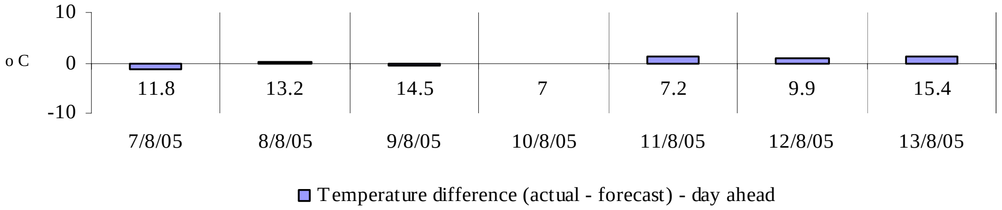












There were 6 occasions in Tasmania where the spot price was greater than three times the weekly average price of $170/MWh. These occurred between 6.30pm and 7.30pm on Wednesday and between 9am and 10am on Friday.

Wednesday, 10 August

6:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	603.50	8000.00	84.60
Demand (MW)	1,616	1,637	1,576
Available capacity (MW)	2,059	2,029	2,059
7:00 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	528.23	7990.77	84.60
Demand (MW)	1,606	1,578	1,558
Available capacity (MW)	2,015	2,029	2,059
7:30 pm	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	1714.94	7990.77	84.60
Demand (MW)	1,586	1,538	1,540
Available capacity (MW)	2,002	2,039	2,059

Conditions at the time saw demand close to forecast with prices lower than those forecast 4 hours ahead. Binding network constraints in predispatch and dispatch impacted on forecast and actual prices. The 5-minute price spiked to $9,000/MWh at 7.25pm.

Friday, 12 August

9:00 am	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	4753.18	58.40	52.10
Demand (MW)	1,654	1,650	1,630
Available capacity (MW)	2,059	2,059	2,059
9:30 am	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	7386.17	58.40	52.10
Demand (MW)	1,651	1,628	1,608
Available capacity (MW)	2,059	2,059	2,059
10:00 am	**Actual**	**4 hr forecast**	**12 hr forecast**
Price ($/MWh)	974.16	58.40	45.01
Demand (MW)	1,590	1,593	1,573
Available capacity (MW)	2,059	2,059	2,059

Conditions at the time saw demand close to forecast. Network constraints affected as much as 160MW of generation, mostly at Gordon. Forecasts showed the unit constrained on at its maximum of 246MW through this period. It was, however, constrained off by as much as 160MW in despatch. Most of this capacity was replaced by higher priced capacity at Poatina and John Butters. The 5-minute price was above $8,000/MWh for 40 minutes.

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

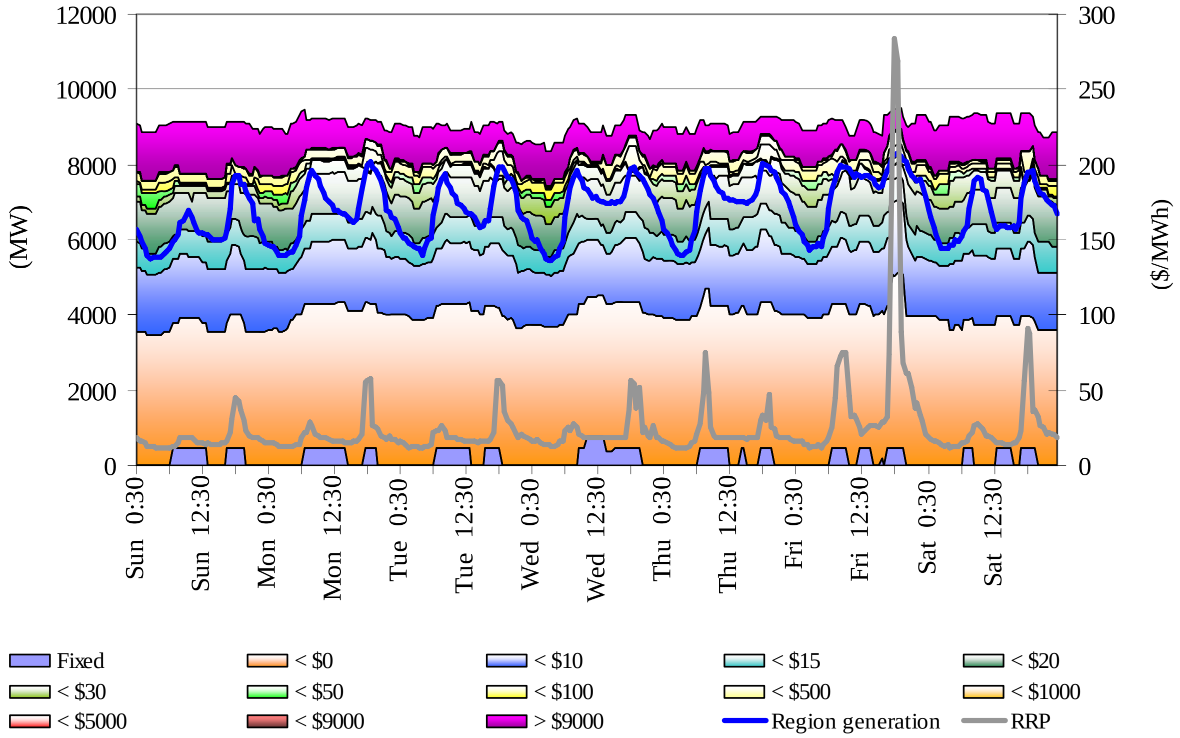


Figure 52: New South Wales closing bid prices, despatched generation and spot price

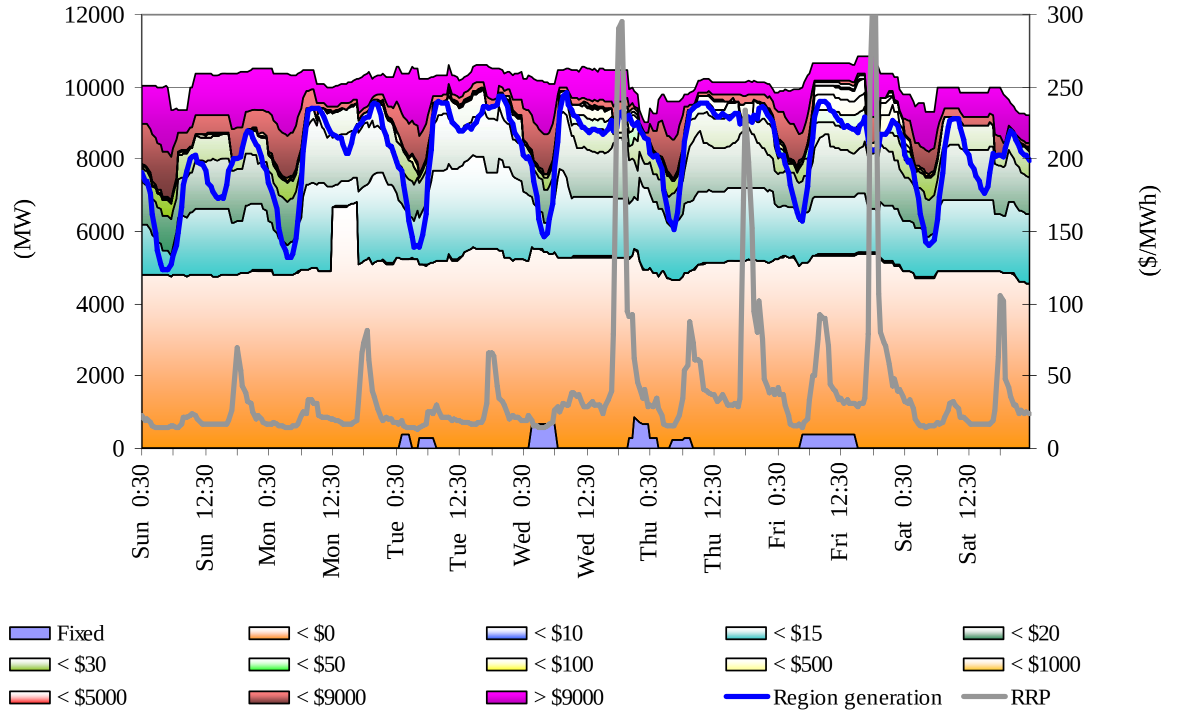


Figure 53: Victoria closing bid prices, despatched generation and spot price

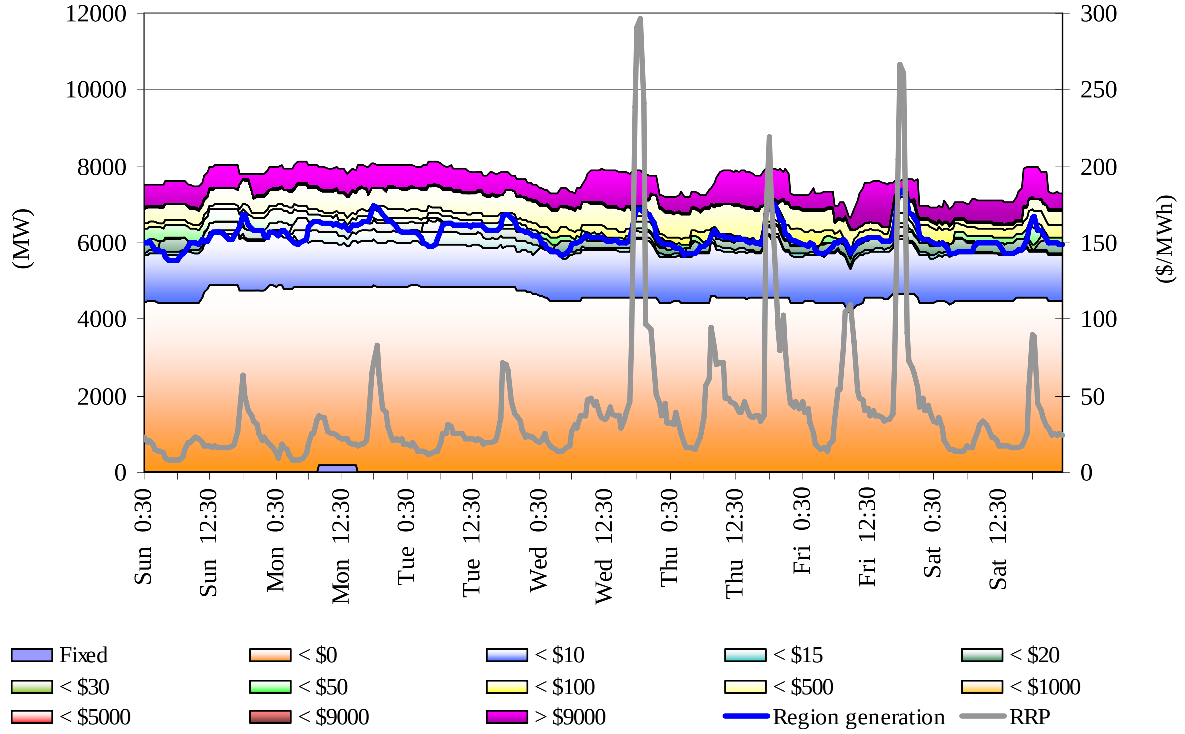


Figure 54: South Australia closing bid prices, despatched generation and spot price

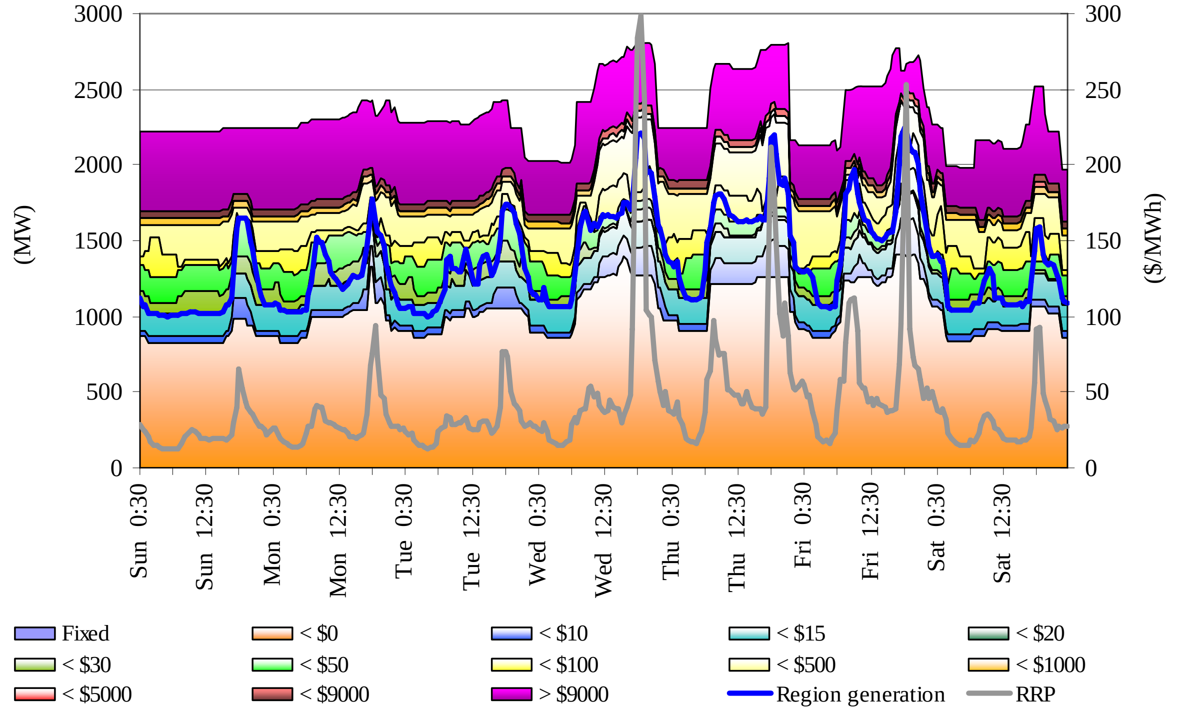
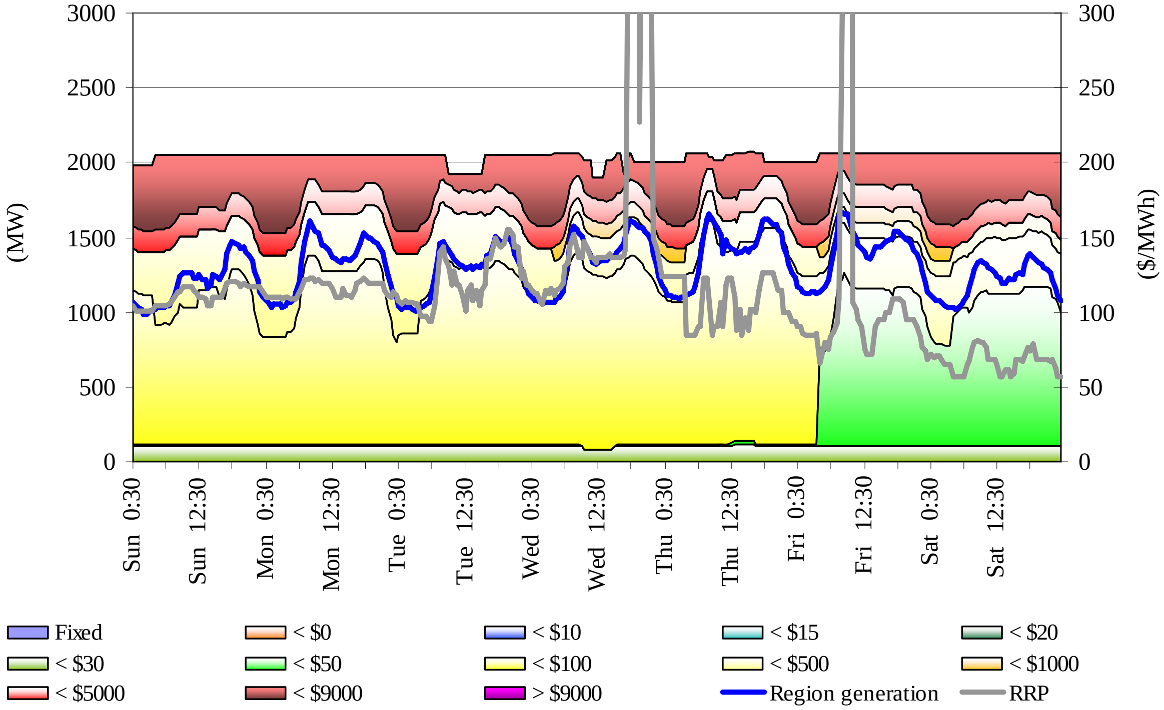


Figure 55: Tasmania closing bid prices, despatched generation and spot price



Ancillary service market

The total cost of ancillary services for the week returned to normal levels at $447,000 or 0.2 per cent of the total turnover in the energy market. High prices for raise regulation and lower 6 second in Tasmania on Friday morning contributed around $80,000 to the total cost, coincident with the high prices 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 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 ($)	0.94	0.49	0.87	1.53	0.15	0.15	1.02	1.52
Previous week($)	1.09	0.75	0.92	1.49	0.16	0.15	1.18	1.43
Last Quarter($)	2.43	0.81	0.99	1.07	0.23	0.96	2.96	1.51
Market Cost ($1000s)	$46	$24	$59	$33	$1	$1	$24	$33
% of energy market	0.03%	0.02%	0.04%	0.02%	0.00%	0.00%	0.02%	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 ($)	1.39	1.05	1.05	5.32	6.50	1.05	1.05	1.12
Previous week($)	126.84	1.05	2.20	4.53	2.72	1.05	1.05	2.57
Market Cost ($1000s)	$13	$10	$12	$45	$81	$31	$26	$10
% of energy market	0.04%	0.03%	0.03%	0.12%	0.22%	0.08%	0.07%	0.03%

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

Figure 58: daily frequency control ancillary service costs

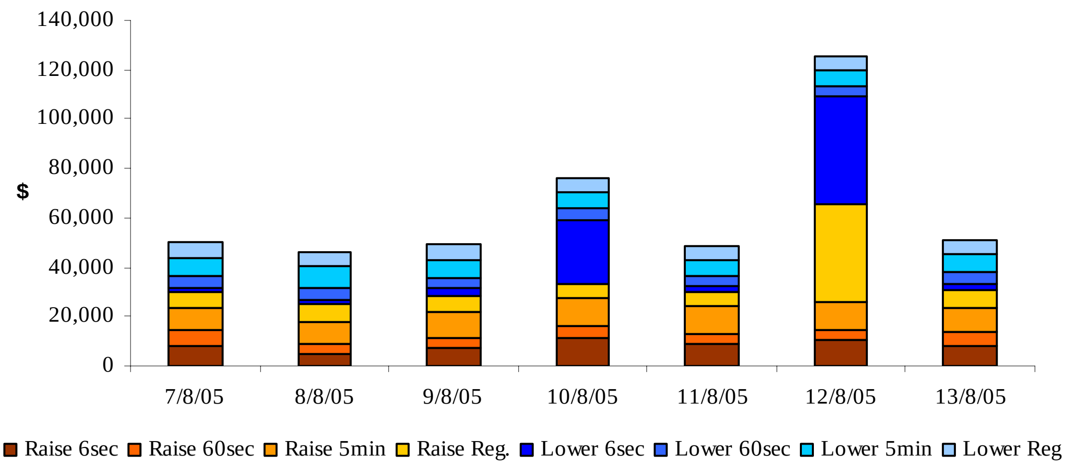
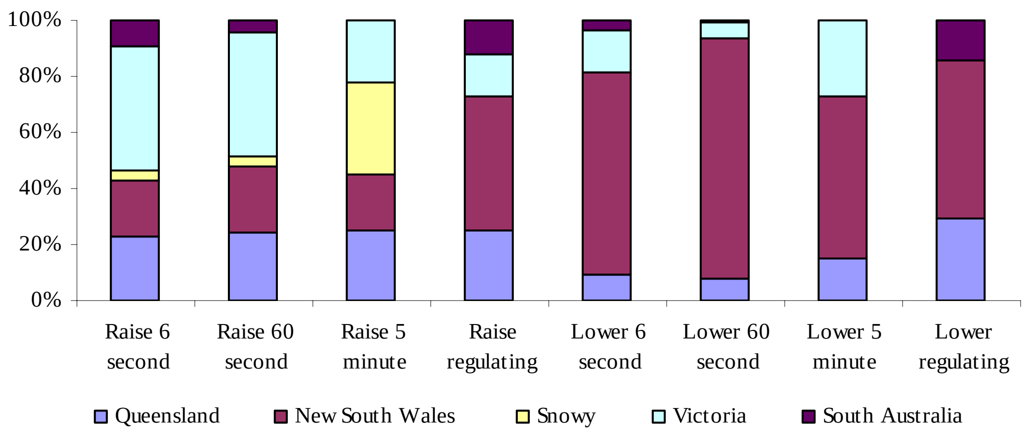


Figure 59 shows the regional weekly participation in each of the ancillary service markets on the mainland.

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

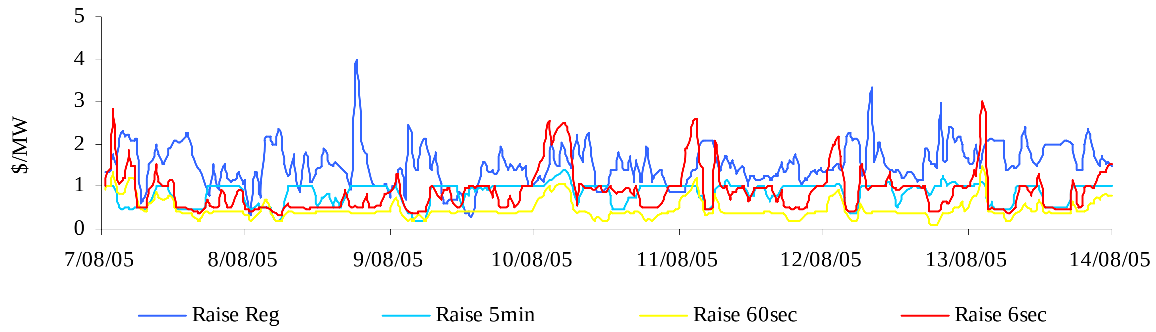


Figure 60A: prices for raise services - Tasmania

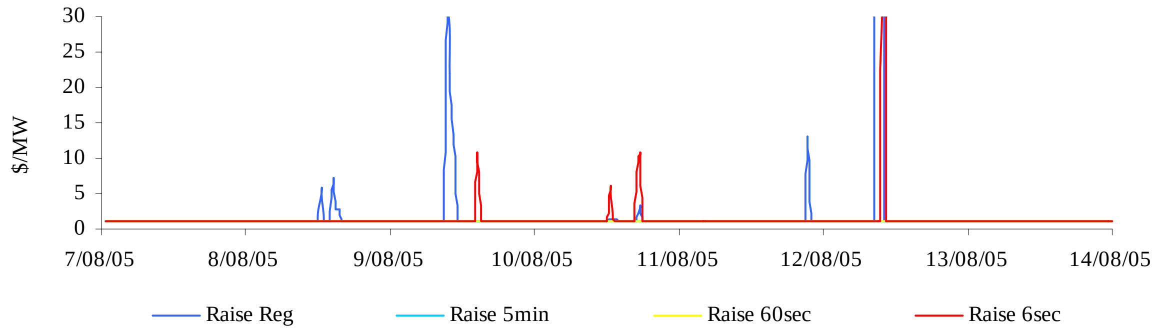


Figure 61: prices for lower services

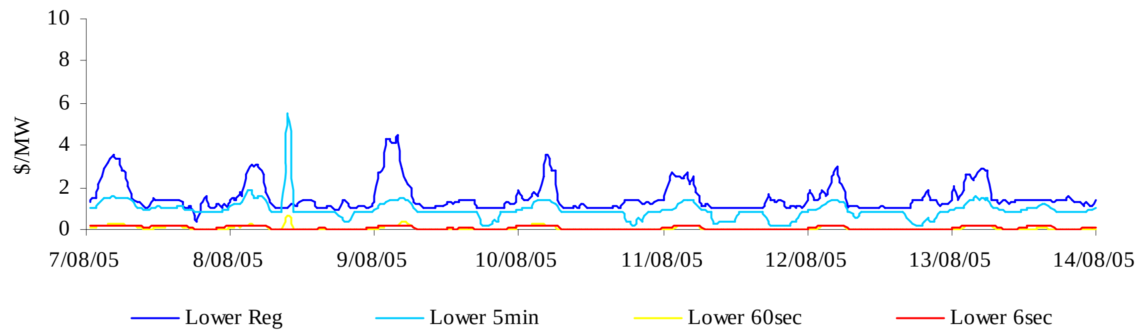
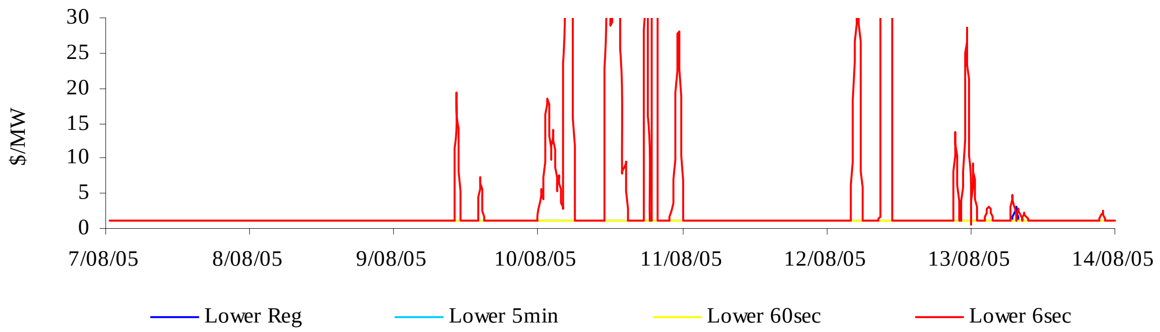


Figure 61A: prices for lower services - Tasmania



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

Figure 62: raise requirements

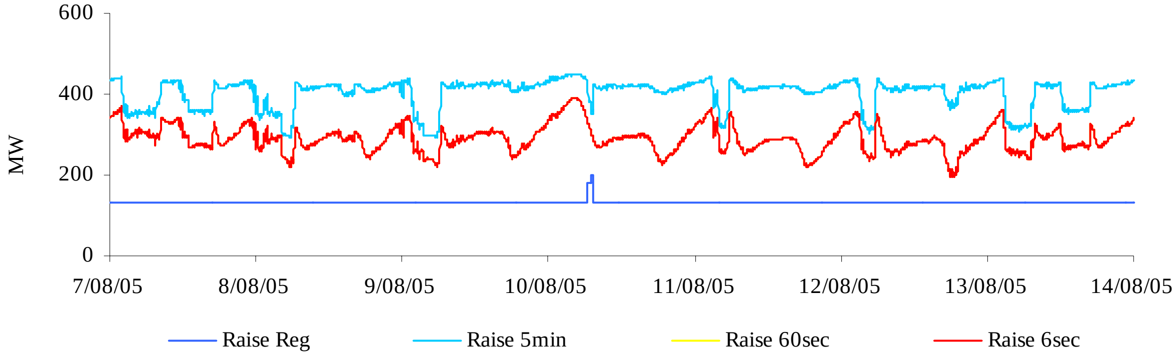


Figure 62A: raise requirements - Tasmania

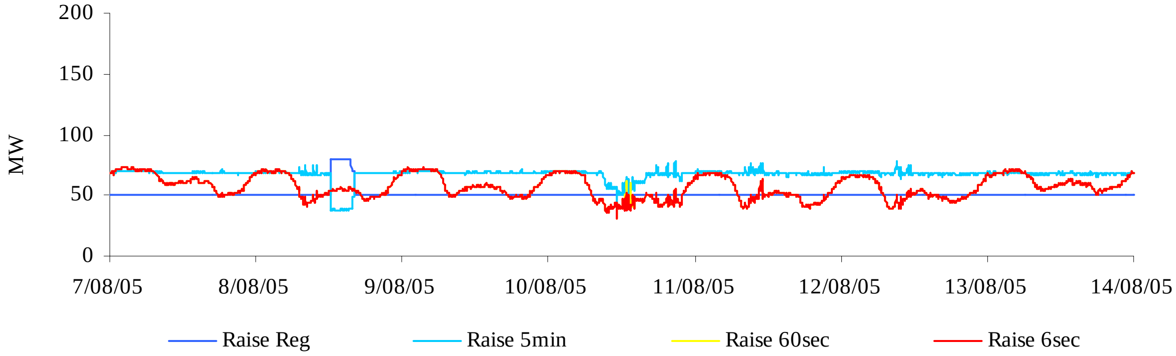


Figure 63: lower requirements

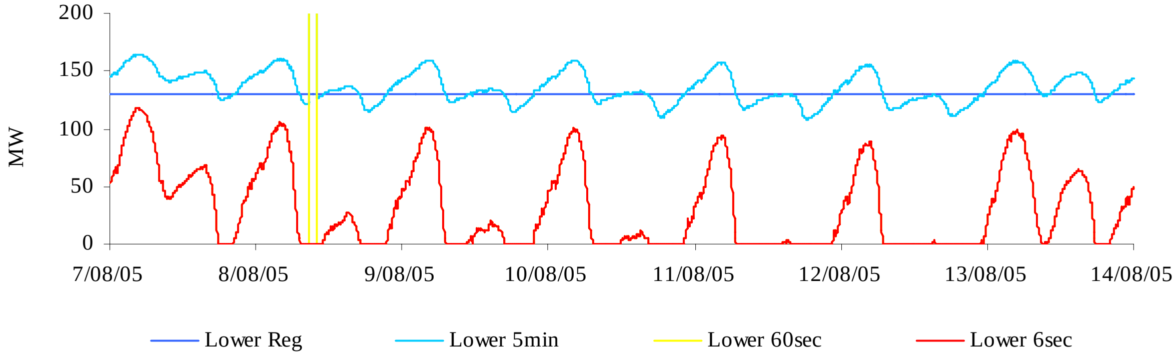


Figure 63A: lower requirements - Tasmania