To	Tim Street, Laurie Counsell – Electricity Commission
From	Ashley Milkop and Daniel Pringle – M-co
Date	26 February 2009
Subject	**13 February 2009 Market Prices**

The Electricity Commission ordered a delay in publication of Final prices for Friday 13 February 2009 because of large price variations resulting from the need to cover an unplanned 320 MW outage at Otahuhu.

This document details aspects of the pricing calculation, notification and market impact of those prices.

Summary of the issue

1. At 10:38 on Friday 13 February, the system operator issued a nation wide frequency and voltage excursion notice advising that 320 MW of generation had been lost at Otahuhu. The system operator set RAFs to zero for the 11:00 trading period in the North Island. The reserve market was reinstated from the 11:30 trading period onwards.

2. During the afternoon of 13 February, the pricing manager received participant queries about high 5 minute prices in the central North Island and discussed them with the Electricity Commission.

1. At 16:57 on 13 February, the pricing manager issued a notice that the Electricity Commission Board had ordered delayed publication of final prices and final reserve prices for Friday 13 February 2009. This order was made under rule 3.28 of section V of part G of the Electricity Governance Rules 2003 (Rules).

2. On Saturday 14 February, the pricing manager calculated prices for 13 February 2009. Provisional prices were published due to infeasibilities and a high spring washer price (HSWP) situation.

3. Branch group constraint OHW_WKM_1_S_O_1 was infeasible at 11:30. This constraint was binding from 11:00 – 12:30, leading to a high spring washer price (HSWP) situation for the 11:00 period. Infeasibility situation and HSWP situation notices were issued.

4. On Monday 16 February, the pricing manger received from the system operator a response to the HSWP notice. In accordance with the Rules, the HSWP relaxation factor of 1 MW was applied to the OHW_WKM_1_S_O_1 constraint limit for the 11:00 trading period for 13 February.

5. The branch group infeasibility at 11:30 was resolved by lifting the constraint limit for OHW_WKM_1_S_O_1 from 61 MW to 64 MW.

6. The second pricing solve led to a new provisional price situation. Lifting the branch group constraint limit led to a new HSWP situation at 11:30. In accordance with rule 3.18.4, the second pricing solve was not published and a new HSWP situation notice was issued by the pricing manager.

7. Relaxing the HSWP constraint at 11:00 led to lower prices. Weaker HSWP situations persisted at some nodes but could not be further reduced as the Rules state that the relaxation can be applied only once for each trading period.

8. A third pricing solve led to a final pricing situation. In the absence of an Electricity Commission order to delay publication of final prices, these prices would have been published. These 'would-be final' prices are analysed below.

9. On Tuesday 17 February, and with approval from the Electricity Commission, the pricing manager issued a notice to market participants regarding the pricing situation for 13 February. The stated purpose of this notice was to inform market participants "of issues surrounding the delay in publishing final prices for Friday 13 February 2009, and to provide … the opportunity to review changes from the presently-published provisional prices that will result if this delay is lifted."

10. This notice included would-be-final prices for trading periods 11:00 and 11:30 on 13 February, and notification that these were the only periods for which prices would change from the published provisional prices.

11. On 18 February 2009 Contact Energy Limited lodged an Undesirable Trading Situation (UTS) claim related to the high prices at Lichfield and the upper North Island.

12. In the pricing manager's opinion, the would-be final prices are legitimate and accurate based on the initial conditions. To the best of our knowledge, the correct inputs have been used and the correct calculation process followed. The resulting prices reflect the constraints and events of 13 February.

13. A load-increase analysis confirms that the unusual would-be final prices at Lichfield (LFD1102, $7540), Penrose (PEN0331, $2174) and Tauranga (TGA0331, -$253) are indeed marginal prices reflecting the cost to supply.

14. Below are prices and reserve prices from the published provisional prices ($/MWh to nearest cent) for the periods in which the OHW_WKM_1_S_O_1 constraint bound:

Period	Period start time	LFD1102	PEN0331	TGA0331	HAY2201	6s Reserve Price	60s Reserve Price
23	11:00	880.68	226.749	-62.67	77.93	zero	zero
24	11:30	74,039.32	18,706.92	-6,134.44	6,067.12	2,938.14	3,065.32
25	12:00	1,488.81	427.01	-49.90	172.97	79.24	30.00
26	12:30	273.76	106.902	29.45	64.35	1.01	19.76

The combination of high prices and negative prices in trading periods 23 to 25 indicates spring washer price effects:

(a) For trading period 23, a HSWP notice was issued; 'zero' indicates that the reserve market was removed by the system operator.

(b) Trading period 24 has both the highest and most negative prices. However, a HSWP notice was prohibited due to the branch group constraint infeasibility.

(c) For trading period 25, no prices triggered the HSWP threshold (price > 5 times the highest unconstrained offer).

15. Below are prices and reserve prices from the 'would-be final' prices ($/MWh):

Period	Period start time	LFD1102	PEN0331	TGA0331	HAY2201	6s Reserve Price	60s Reserve Price
23	11:00	570.11	163.78	-19.25	66.20	zero	zero
24	11:30	7,539.57	2,174.70	-253.37	910.19	346.60	500.00
25	12:00	1,488.81	427.01	-49.90	172.97	79.24	30.00
26	12:30	273.76	106.90	29.45	64.38	1.01	19.76

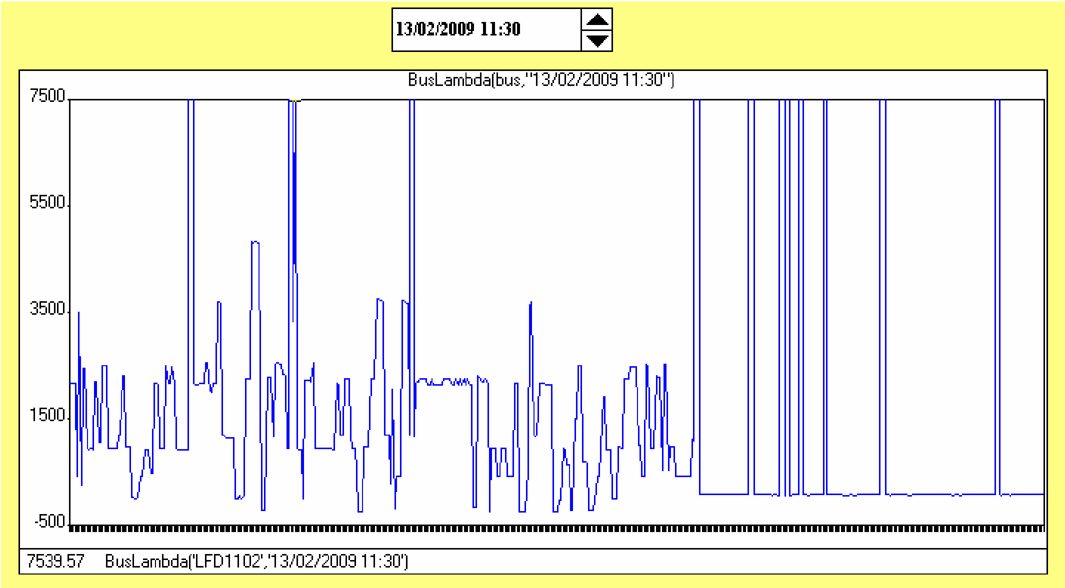
In comparison with the prices in paragraph 14, note here:

(a) Lower (or less negative) prices in trading periods 23 and 24 due to HSWP constraint relaxation.

(b) Reserve prices are greatly reduced for trading period 24.

(c) Prices in trading periods 25 and 26 are unaffected. More generally, the third solve (would-be final) prices differ from the published provisional prices only in periods 23 and 24.

16. The plot below shows prices for the third solve at 11:30. North Island nodes are on the left two-thirds of the chart. They show prices above $1000/ MWh at many nodes, and several nodes with negative prices. The flat line on the right shows low South Island prices, and the vertical lines indicate disconnected nodes.



17. In normal circumstances, the prices from the third pricing solve would be published as final even if a HSWP situation applies, as the Rules state that relaxation of the security constraints can only be performed once.

18. The analysis presented at the end of this document has been performed using the inputs to the third pricing solve, and the prices derived from it.

19. There were some estimated nodes in the pricing. The number and nature of these nodes were not sufficient to declare a metering situation. The estimated nodes were BOB1101, HWA1102, KUM0661, MDN0141, WRK0331.

20. The following branch group constraint bound in the third pricing solve for periods 23-26:

    OHW_WKM_1_S_O_1

    This grid owner constraint relates to flows over HAM_WKM.1 and KIN_TRK2.1. The effect of this constraint is to manage flows through Kinleith Tarukenga 1 for a contingency of Hamilton Whakamaru 1 during high Zone 1 load and low Zone 1 generation when Ohinewai Whakamaru 1 is out of service.

21. No other North Island group or line constraints exceeded 95% of their limits on 13 February 2009.

Financial effect on spot market participants

22. To estimate the effect of the would-be final prices on participants, an exercise was conducted as follows.

23. For period 24 the net position of the eight most affected parties was calculated using reconciled purchase and generation data from Wednesday 13 February 2008 (i.e. the same day, previous year) and would-be final prices from the third pricing solve for 13 February 2009.

24. Note that reconciled generation and purchases data from 13 February 2008 were used as a reasonable estimate of the as-yet-unavailable reconciled data for 13 February 2009.

25. As a comparison scenario, a 'business as usual' estimate was made using the same generation and purchase data from 13 February 2008, but with published final prices from Thursday 12 February 2009 (i.e. the previous day).

26. Important notes for the table below:

    (i) We consider energy generation and consumption only, we do not include reserves.

    (ii) Net position is here from a participant perspective: net position equals generation revenue less consumption costs. A negative number is a loss.

    (iii) Impact is the difference between the two scenarios. A negative impact means the party is worse off with the would-be final prices than the comparison case.

    (iv) Less-impacted parties are not listed.

	(A) Net position Would-be Final prices 13/02/09	**(B) Net position Final prices 13/02/08**	**Impact (A) – (B)**
Party A	- 218,591	168	- 218,760
Party B	406,605	- 8,217	414,822
Party C	- 31,495	735	- 32,230
Party D	- 138,348	987	- 139,335
Party E	- 442,462	260	- 442,722
Party F	8,517	- 18	8,535
Party G	- 235,035	10,312	- 245,347
Party H	25,204	- 2,747	27,952

Here Net position = generation revenue – consumption costs
Negative Impact is a worse position.

27. We stress that these net positions are based on estimated purchase and generation data (from 13 February 2008). Nevertheless, the estimated positions would require an increase in prudential security for several parties.

Comparison with other published prices

28. The following table shows a price comparison for trading period 24 of other published prices against both the published provisional prices and the would-be final prices at select nodes ($/MWh to nearest dollar):

Prices for TP24, 13-Feb-2009	LFD1102	PEN0331	TGA0331	HAY2201
Calculated half hour Provisional price	74,039	18,707	-6,134	6,067
Calculated half hour would-be final price	7,539	2,175	-253	910
Peak 5 minute price*	73,135	23,506	-9,932	6,957
Average 5 minute price	73,120	18,695	-7,597	5,530
Dispatch (SDPQ) price	4,081	1,061	-291	370
Forecast price	1,589	421	-104	152

* Here peak price is the price with the highest absolute value in the trading period.

29. The provisional half-hour price at LFD1102 exceeds the other published prices. For the other nodes shown, the provisional price is closest to the average 5 minute price.

30. For completeness, the 5 minute prices for these nodes during trading periods 23 – 26 are listed below:

Time	LFD1102	PEN0331	TGA0331	HAY2201
11:00	381.3	108.08	-13.01	45.33
11:05	713.03	183.72	-50.73	63.71
11:10	758.39	193.57	-56.11	65.62
11:15	759.17	193.39	-56.16	65.63
11:20	2,622.18	633.89	-252.97	174.08
11:25	4,439.1	1,063.91	-444.92	283.46
11:30	100,000*	23,505.97	-9,931.8	6,956.6
11:35	73,075.33	17,688.19	-7,179.53	5,216.94
11:40	73,128.15	17,743.98	-7,122.04	5,270.56
11:45	73,130.92	17,743.00	-7,117.68	5,255.98
11:50	73,134.72	17,744.66	-7,112.83	5,242.64
11:55	73,131.69	17,741.37	-7,116.09	5,239.83
12:00	1,065.24	305.37	-35.9	123.74
12:05	1,065.41	305.39	-35.96	123.74
12:10	1,063.73	304.93	-35.87	123.74
12:15	1,004.88	293.76	-26.17	123.68
12:20	1,037.91	300.29	-31.2	123.66
12:25	928.98	272.89	-23.34	116.61
12:30	800.96	247.75	0	114.85
12:35	253.23	106.86	36.57	67.2
12:40	77.33	83.69	78.87	74.59
12:45	55.45	60.04	56.43	53.83
12:50	56.15	60.69	56.61	54.33
12:55	77.31	83.52	77.99	74.55

* This 100,000 price is a model parameter.

31. The 5 minute price, dispatch price and forecast price are calculated by the system operator. Further information should be sought from them in regard to these pricing outcomes.

Price explanation and verification

32. We have examined trading period 24 prices in the would-be final prices for 13 February 2009.

33. As detailed in the above tables, prices in trading period 24 at Lichfield were significantly higher than in other trading periods during the day. The relevant constraint, OWK_WKM_1_S_O_1, which restricts flows over HAM_WKM.1 and KIN_TRK1.2, bound between 11:00 and 12:30.

34. In order to cover the loss of 320 MW of generation at Otahuhu, there was an increase in the flow from the Waikato to Auckland region, including an increase in flow north along WKM_HAM.1. In accordance with branch group constraint OHW_WKM_1_S_O_1, this constrained flows to LFD1102 northwards along KIN_TRK_1.2.

35. We have applied a marginal load analysis for select test nodes for trading period 24. This analysis confirms that these prices do in fact represent the marginal cost price in the presence of the above binding constraint.

36. The system was highly sensitive to additional load, requiring the analysis to be done with a smaller load increment. We used a 1 kW load increase.

37. In this case, the increase in system cost equalled the node price, confirming that the node price was a legitimate marginal price. Results below are scaled up from this +1 kW calculation to a +1 MW increase. Participant names have been substituted to protect confidentiality until such time as offers are published.

Marginal Price at LFD1102

38. The theoretical 1 MW demand increase at LFD1102 resulted in a system cost increase of $7539.57 comprising:

    a. $1459.88 for energy; and

    b. $6079.68 for reserve.

39. The 1 MW increase was modelled by an energy output increase of 12.16 MW at generator 'A' and an energy output decrease of 10.8 MW at generator 'B'. Losses were 0.36 MW.

40. The energy increase at 'A' cost $1459.88 (for $120.06 price) and the decrease at 'B' saved $0.00 (for $0.00 price).

41. Changes in modelled reserves were to increase interruptible load reserve (ILRO) at reserve 'X' by 12.16 MW, and decrease tail water depressed reserve (TWRO) at reserve 'Y' by 12.16 MW.

42. The ILRO increase at 'X' cost $6,079.80 (for $500 reserve price) and the TWRO decrease at 'Y' saved $0.12 (for $0.01 reserve price).

43. The net marginal cost of supplying the theoretical 1MW to LFD1102 is therefore $6,079.80 + $1,459.88 - $0.12 = $7,539.57. This equals the calculated price at this node for the trading period.

Marginal Price at PEN0331

44. An identical analysis for PEN0331 gave a system cost increase of $2,174.70 comprising:

    c. $421.09 for energy; and

    d. $1753.61 for reserve.

45. The 1 MW increase was modelled by an energy output increase of 3.51 MW at 'A' and an energy output decrease of 2.3 MW at 'B'. Losses were 0.21 MW.

46. The energy increase at 'A' cost $421.09 (for $120.06 price) and the decrease at 'B' saved $0.00 (for $0.00 price).

47. Changes in modelled reserves were to increase ILRO at 'X' by 3.51 MW, and decrease TWRO at 'Y' by 3.51 MW.

48. The ILRO increase at 'X' cost $1,735.65 (for $500 reserve price) and the TWRO decrease at 'Y' saved $0.04 (for $0.01 reserve price).

49. The net marginal cost of supplying the theoretical 1 MW to PEN1102 is therefore $1,753.65 + $421.09 - $0.04 = $2,174.70. This corresponds to the calculated price at this node for the trading period.

Conclusion

50. The pricing manager is satisfied that the would-be final prices for period 24, 13 February 2009, as calculated on 16 February 2009, are correct to the extent that:

    a. The pricing process was performed correctly;

    b. Action undertaken by the system operator to resolve the infeasible branch group constraint and related HSWP situations was correct and in keeping with the Rules; and

    c. To the best of our knowledge, the inputs provided under the Rules by other parties which are required to perform the pricing process were present and correct.