Determination of Critical Contingency Price

in respect of the critical contingency of 24th May 2016

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18th July 2016

Introduction

1. This report sets out my determination of a Critical Contingency Price as required by the Gas Governance (Critical Contingency Management) Regulations 2008 ('the Regulations'). The Critical Contingency Price is required in respect of the critical contingency of 24th May 2016.

2. A critical contingency is defined under the Regulations. It is triggered when the operating pressure reaches a low threshold that defines the pressure required to "maintain the supply of gas across the relevant part or parts of the transmission system and to avoid disruption of distribution systems connected to the transmission system" (Regulation 25(1)(a)(iv)).

3. This report is updated from an initial report (dated 27th June) and draft price estimate which was discussed at a workshop with interested parties on 30th June 2016. Subsequent to that workshop written submission were received by several parties on that original report and to a revised note dated the 6th July. I am very grateful for those comments; they have assisted in my final determination and many of the points raised have been incorporated into this final report.

4. My final determination is that the critical contingency price for 24th May 2016 is $6.66/GJ. The explanation is given below.

The Event

5. At 16:20 on the 24th May, Pohokura Production Station suffered an unplanned outage. The loss of gas production combined with the large gas demand at the time resulted in depleting linepack and pressures such that the critical contingency threshold of 3 hours to 37.5barg at the Kapuni Gas Treatment Plant (KGTP) was breached. The Critical Contingency Operator (CCO) determined that the critical contingency conditions had occurred and it declared a critical contingency at 18:30.

6. At 18:46 the operator of the Pohokura Production Station advised the CCO that the problem had been resolved and that Pohokura should be back to full flow rates within two hours. The CCO also spoke to the operators of other gas fields who were able to increase gas production and/or curtail their customers. On this basis, the CCO determined that no curtailment under the CCM Regulations was required.

7. The CCO terminated the critical contingency at 23:00. The duration of the critical contingency was 4 hours and 30 minutes.

Concepts Relevant to Setting a Critical Contingency Price

8. The purpose of the critical contingency price and guidance on setting price is provided under Sections 67 and 71 of the Regulations (Box 1).[1]

Box 1 Regulatory Sections relating to Critical Contingency Price

67. **Purpose of applying critical contingency price to contingency imbalances**

The purpose of regulations 68 to 71 is to determine a critical contingency price to be applied to the contingency imbalances sustained by interconnected parties and shippers during a critical contingency to—

(a) avoid shippers instructing their suppliers of gas to reduce supply during a critical contingency when those shippers' consumers have been curtailed; and

(b) signal to suppliers and consumers of gas that it is a scarce and valuable product during a critical contingency; and

(c) provide incentives before a critical contingency, particularly for retailers who supply gas to consumers who are unlikely to be curtailed, to make alternative arrangements to minimise the financial consequences of a critical contingency.

71. Determining critical contingency price

(1) The industry expert must determine the critical contingency price in dollars per gigajoule of gas.

(2) The industry expert must seek to set the critical contingency price at a level that reflects the price that would be established by an efficient short-term market that allocated scarce gas resources to the highest value uses during the critical contingency.

(3) If—

(a) only consumers in curtailment bands 0 and 1a, or 0, 1a, and 1b, were curtailed during the critical contingency, the industry expert must base his or her determination on the prices in the wholesale market for electricity during the critical contingency except where that would be contrary to subclause (2); and

(b) any other circumstances apply, the industry expert must take into account the following matters:

(i) the prices in the wholesale market for electricity during the critical contingency; and

(ii) the economic cost of the loss of gas supply to those consumers who had their gas supply curtailed; and

(iii) any other matters that the industry expert considers relevant to achieving subclause (2).

Source: Gas Governance (Critical Contingency Management) Regulations 2008

9. Section 71 describes how to set the critical contingency price, but this needs to be interpreted in the light of the overall purpose of the price (Section 67). The price needs to:

- encourage available supply;
- signal scarcity; and
- provide incentives to retailers to make arrangements to minimise the financial consequences of a critical contingency if one was to occur.

[1] Sections 68 to 70 address the appointment of the industry expert

10. The implications of this are that the price should be relatively high and certainly higher than market price expectation in the absence of a critical contingency.

11. In the critical contingency of 24th May 2016 there was no curtailment as defined under the Regulations. This means that the relevant Sub-Sections of Section 71 which must be taken into account are 1, 2 and 3(i) only, ie the price must:
    - be in $/GJ;
    - be set to reflect a price that would allocate gas efficiently during the contingency; and
    - be set taking into account prices in the wholesale electricity market and any other matters relevant to allocating gas efficiently during the critical contingency.

Approach Used to Define the Critical Contingency Price

12. There have been two previous analyses of a critical contingency price.

13 July 2010

13. In 2010 there was a critical contingency lasting for approximately 3 hours. There was no curtailment and a price of $15/GJ was set based on prices paid for balancing gas on the day.[2]

14. The industry expert (Dr John Small) considered electricity generators as possible providers of gas to the wholesale gas market, such that the wholesale electricity price could be used to estimate the opportunity cost of gas supply. However, he suggested that the wholesale electricity price is not necessarily the price that would emerge from an efficient spot market for gas if it was operating during the critical contingency. Dr Small noted that, if gas use by electricity generators was curtailed, electricity prices would increase such that the price based on willingness to pay (WTP) would be an under-estimate of price in a hypothetical spot market.

15. He calculated that the e3p (Huntly unit 5) CCGT generating plant would have a WTP of up to $12.85/GJ for gas. However, a price of $15/GJ was paid for gas in the balancing gas exchange market. He suggested that this was a better approximation to the critical contingency price because it was actually paid for gas in an attempt to restore pressure.

20 April 2012

16. In 2012 there was a critical contingency lasting close to 11 hours, resulting in curtailment of bands 0, 1a and 1b (gas storage, electricity generators and other large consumers):
    - curtailment was required of Te Rapa Cogeneration plant and Southdown power station;
    - no gas was allocated to Taranaki Combined Cycle (TCC) and the Stratford peakers as they had access to stored gas; and

[2] John Small (2010) Critical Contingency Price: 13 July 2010 Final Report, 6 September2010

- the other combined cycle plants (e3P and Otahuhu B) were allocated gas as high value users.

17. The critical contingency price was estimated as a gas price at which the CCGTs (which were not curtailed) would continue to operate but that Southdown (which was curtailed) would not. Using a netback calculation of the WTP for gas by these plants, the critical contingency price was set at $11.10/GJ.[3]

18. The wholesale price of electricity during the critical contingency reflected a situation in which some gas plants were not generating such that the electricity price reflected the gas scarcity at the time.

Approach for This Contingency

19. The previous examples differ in the circumstances of the critical contingency (curtailment or not) and the approach used to estimating price. For the critical contingency of 24th May 2016 we re-examine the approach suggested in Section 71, including the relationship to the wholesale electricity price and the consideration of other matters.

20. A number of factors that could be considered are set out below.

    - The price is to be one which would allocate gas to the highest value uses during the critical contingency. If electricity generators are defined as high value users, a price based on their WTP could be defined as a maximum value for the critical contingency price. However, if they are not defined as high value users, the WTP might be used to define the minimum.

    - Prices paid in the gas spot market on the day provide some guidance on whether electricity use is a high value use or not. These prices might also provide information on the minimum value, on the basis that they might need to be above these values to encourage additional supply.

    - To the extent that they are higher, prices paid in the balancing market might provide additional information on the value of gas on the day.

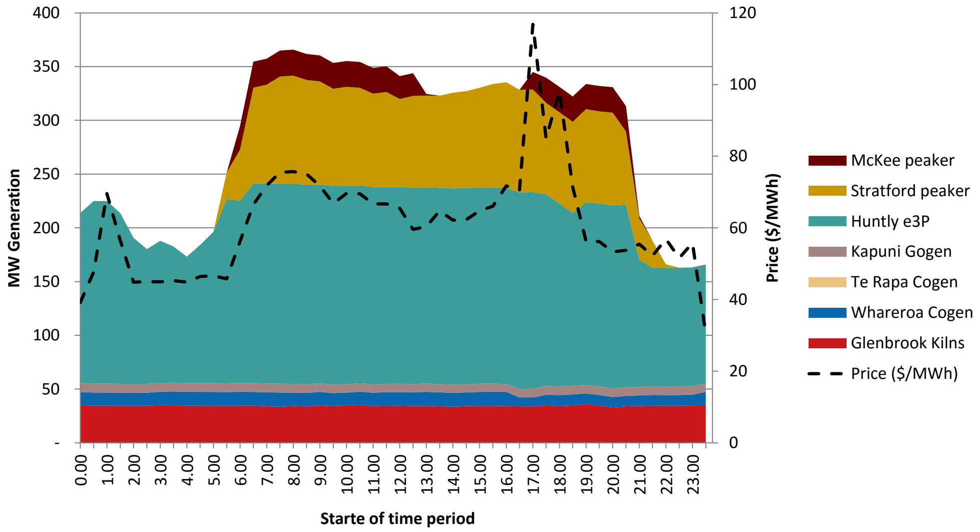
Electricity Market Information

Generation and Market Prices

21. Figure 1 shows the generation from gas-fired plants on 24th May. The co-generation plants operated continuously and at an approximately constant rate, with output determined by heat demand. During the time of the critical contingency (18:30 to 23:00) McKee and Stratford peakers plus e3P all reduced generation.

[3] Tim Denne (2012) Determination of Critical Contingency Price in respect of the critical contingency of 3rd March 2012

Figure 1 Gas-fired electricity generation and electricity price 24th May 2016



Source: Electricity Authority; Covec analysis

22. The reduction in generation does not appear to be a response to electricity price. Figure 1 includes the average price across the three nearest price nodes to the three generating plants.[4] The wholesale electricity price fell from an average $98/MWh at 18:00 to $56/MWh at 19:00, whereas generation did not reduce significantly until 20:30 for all three plants. From an analysis of generation on dates either side of the critical contingency, this behaviour appears to be typical of generation throughout the week of the critical contingency.

23. Plant-specific information on heat rates and costs is provided in Table 1. McKee and Stratford peakers have the highest heat rates (lowest efficiencies) such that they are the marginal plants with the lowest willingness to pay for gas; if they were responding efficiently to market prices the peakers would be the first to reduce output when electricity prices fell or if gas prices rose. We discuss below (paragraph 25) why they are not responding efficiently.

Table 1 Gas plant information and assumptions

	E3P	McKee Peaker	Stratford Peaker
Heat rate (GJ/GWh)	7,300	10,500	10,600
Variable cost ($/MWh)	$4.40	$8.00	$6.50
Gas transmission cost ($/GJ)	$0.50	$0.00	$0.14
CO_2 Emissions Factor (kg/GJ)	53.24	53.24	53.24
CO_2 price	$14.15	$14.15	$14.15
$/GJ (@ 2 for 1)	$0.38	$0.38	$0.38

Source: MBIE Electricity Demand and Generation Scenarios: Generation Cost Assumptions; Personal communications from Contact and Todd Energy; MBIE Energy Greenhouse Gas Emissions; OMF Carbon Daily Report 24 May 2016

[4] HLY2201, MKE1101 and SFD2201

Estimates of Willingness to Pay for Gas

24. We use the data in Table 1 to estimate a WTP for gas given the wholesale electricity price at the nearest pricing node for each plant. The results over the critical contingency period are shown in Table 2. The estimated WTP for gas is estimated using the following equation.

$$WTP = \frac{(WP - VC)}{HR} - GTC - CC$$

Where: WTP = willingness to pay for gas (in $/GJ)
WP = wholesale price of electricity ($/MWh)
VC = variable cost of generation ($/MWh)
HR = heat rate in GJ/MWh (note these are expressed above in GJ/MWh)
GTC = gas transmission cost ($/GJ)
CC = carbon cost ($/GJ)

Table 2 Wholesale electricity price per node and resulting willingness to pay for gas

		Pricing node			Plant	
Period starting	HLY2201	MKE1101	SFD2201	e3P	McKee Peaker	Stratford Peaker
		$/MWh			$/GJ	
18:30	$75.48	$68.81	$69.90	$8.86	$5.41	$5.46
19:00	$60.01	$53.90	$54.78	$6.74	$3.99	$4.04
19:30	$60.01	$53.79	$54.67	$6.74	$3.98	$4.03
20:00	$56.68	$51.21	$52.04	$6.28	$3.74	$3.78
20:30	$57.49	$51.47	$52.30	$6.40	$3.76	$3.80
21:00	$58.38	$54.24	$53.87	$6.52	$4.03	$3.95
21:30	$55.01	$50.98	$50.64	$6.06	$3.72	$3.65
22:00	$58.83	$56.07	$55.71	$6.58	$4.20	$4.13
22:30	$53.10	$50.98	$50.64	$5.79	$3.72	$3.65

Note: shaded values are when the plant is not generating

Source: Electricity Authority datasets Wholesale; Covec analysis

25. The lowest values are the WTP values for McKee and Stratford. These are below the spot market price for gas on 24th May (see below). This might be explained by:

- The generators (Contact Energy and Todd) making decisions on gas use in the context of having: (1) a low cost of supply, reflecting either a take or pay agreement (Contact) or gas being effectively a by-product of oil extraction (Todd), and (2) limited demand for gas in the market which would otherwise enable on-sale; and

- Managing risk of price spikes in the retail electricity market and costs of ramping up and down, which means generation decisions are likely to be made on the basis of price averages over a period of several hours.

26. The other issue of note is that both McKee and Stratford have access to stored gas, such that they would be likely not to be provided with gas during a critical contingency in which curtailment was required.

27. For these reasons, we do not consider the WTP by the peakers as useful in setting the critical contingency price.

28. The WTP at e3P provides a possible estimate of the value of use by a high value use of gas (71(2)). The average WTP over the critical contingency period was $6.66/GJ.

29. If electricity generation is not regarded as the highest value use under Section 71(2), it would be necessary to define a price which would allocate gas to other users, ie a price at which e3P would not generate. Assuming wholesale electricity prices would remain the same in the absence of e3P, this would be a gas price just above $6.66/GJ. However, if electricity prices rose as a consequence, the calculation becomes more complex, requiring modelling of the price as opposed to observance of the market price. This would not appear to be consistent with the requirements of Section 71(3)(b)(i) of the Regulations.

Market Prices of Gas

30. Data from EMS suggests that prices in the physical market on 24th May 2016 ranged from $5.25 to $5.85/GJ with a volume weighted average price (VWAP) of $5.62/GJ.[5] The marginal buy price[6] on the 24th May was $5.75/GJ.[7]

31. These values can be assumed to represent a floor for the critical contingency price. These prices traded during a period in which there was no actual scarcity of gas and are not unusual. The VWAPs on the 23rd and 25th of May, for example, were $5.62/GJ and $5.67/GJ respectively.

32. The market prices of gas are lower than the estimated WTP for gas by e3P over the period, suggesting that it was a high value use of gas.

Critical Contingency Price

33. In determining a critical contingency price I am steered by Section 71 of the Regulations (Sub-Sections 2 and 3(i)) that I must take account of prices in the wholesale electricity market in deciding the price that would allocate gas efficiently during the contingency.

34. Within the wholesale market, the peakers do not appear to provide useful information for setting price. Their WTP for gas is below the market price,

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[5] http://www.emstradepoint.co.nz/market-results/

[6] The Marginal Buy Price is calculated as the higher of: (i) the highest transaction price per GJ of any Balancing Gas Call (a transaction where MDL purchases Gas with the objective of increasing Line Pack), using a Standard Product, made for delivery that Day; or (ii) the Average Market Price for that Day plus an adjustment.

[7] https://www.bgix.co.nz/prices

suggesting that they are not behaving consistently with an efficient short run gas market. Rather other factors, including existing contracts, are determining their behaviour. In contrast, the estimated WTP for gas by e3P is higher than market prices on 24th May and is equivalent to the value of gas in its highest value use within the wholesale electricity market.

35. Alternatively, if e3P is viewed to not be a high value use, a price just above the WTP would allocate gas to other higher value users (assuming no wholesale price response to e3P not generating or to an increased gas price).

36. A price that used the WTP of e3P ($6.66/GJ) as a maximum and a high market price ($5.85/GJ) as a minimum, would:
- Signal scarcity (67(b));
- Make use of prices in the wholesale electricity market (71(3)(i));
- Allocate gas to the highest value use within the wholesale market, and on the evidence of market prices, allocate it to higher value uses than other gas users that day also (71(2));
- Make use of other matters considered relevant to achieving efficient allocation (71(2)).

37. In choosing a price within this range, I am aware that the critical contingency price also plays a role in signalling to the market the value of supplying gas during a critical contingency and that on previous occasions significantly higher values were estimated. For this reason I am minded to set the price at the high end of this range.

38. My determination is that the critical contingency price for the 24th May 2016 is $6.66/GJ.