FIRST REPORT

Prepared for:

Queensland Competition Authority

Level 19, 12 Creek Street

Brisbane QLD 4000

Calculation of the Benchmark Retail Cost Index 2009-10

Prepared by:

CRA International

Level 31, 570 Bourke Street

Melbourne VIC 3000

Date: 15 August 2008

CRA project no: D13563-00

Author(s): L Hoch, D Prins, P Dodgson

DISCLAIMER

CRA International and its authors make no representation or warranty as to the accuracy or completeness of the material contained in this document and shall have, and accept, no liability for any statements, opinions, information or matters (expressed or implied) arising out of, contained in or derived from this document or any omissions from this document, or any other written or oral communication transmitted or made available to any other party in relation to the subject matter of this document. The views expressed in this report are those of the authors and do not necessarily reflect the views of other CRA staff.

TABLE OF CONTENTS

1. INTRODUCTION 1

1.1. BACKGROUND 1

1.2. ORGANISATION OF THIS REPORT 2

2. THE REQUIREMENTS FOR CALCULATION OF THE BRCI 4

2.1. CALCULATION OF THE BRCI AS BENCHMARK RETAIL COST PER UNIT OF NET LOAD 4

2.2. THE TOTAL BENCHMARK RETAIL COST 4

2.2.1. Cost of energy 5

2.2.2. Network costs 6

2.2.3. Retail costs 6

2.2.4. Other relevant costs 7

2.3. WORKING OUT THE NEM LOAD 8

2.4. FIXING OF FUTURE PRINCIPLES 8

2.5. INPUTS FROM THE AUTHORITY'S CONSULTATION PROCESS 8

2.6. CRA'S TERMS OF REFERENCE FOR THIS STUDY 9

2.7. DATA PROVIDED BY THE AUTHORITY 10

2.8. QUEENSLAND GOVERNMENT POLICY OBJECTIVE 11

2.8.1. Headroom in the tariffs – the first policy intent 12

2.8.2. Margins available to retailers serving customers that revert to notified prices – the second policy intent 17

2.9. TIMETABLE TO DETERMINE THE BRCI FOR 2009-10 18

2.10. CUT OFF DATES FOR DATA AND INFORMATION TO BE INCLUDED IN CRA'S REPORTS 19

2.11. INFLATION FORECASTS 19

2.11.1. Consumer price index (CPI) 19

2.11.2. Wage price index (WPI) 20

2.12. CONSEQUENCES OF THE EARLIER TIMETABLE 20

3. COST OF ENERGY 22

3.1. ENERGY COST FRAMEWORK IN QUEENSLAND 22

3.2. THE LRMC OF ENERGY 24

3.2.1. LRMC considerations and approach 24

3.2.2. Definition of the LRMC 26

3.2.3. Issues in modelling of the LRMC 27

3.2.4. Options and approaches taken to the LRMC conceptual framework 29

3.2.5. Options available and approaches taken in the LRMC modelling 32

3.2.6. The CRA model used to derive the LRMC 33
3.2.7. Summary of submissions to the Interim Consultation Notice relating to the LRMC 35
3.2.8. Effect on the LRMC calculation of the requirement to complete the BRCI process by 1 December 2008 37
3.2.9. Forecasting the remainder of the calendar year 2008 load 38
3.2.10. Likely introduction of an emissions trading scheme (ETS) 44
3.2.11. Renewable Energy Targets 46
3.2.12. LRMC modelling input assumptions 47
3.2.13. LRMC results 58
3.3. COST OF PURCHASING ENERGY 60
3.3.1. Conceptual comparison between the LRMC and actual costs 61
3.3.2. Approach to estimating the actual cost of purchasing energy 61
3.3.3. Inputs to the calculation of the cost of purchasing energy 64
3.3.4. Calculations 67
3.3.5. Application of network losses 69
3.3.6. Energy purchase costs results 70
3.4. COMBINATION OF LRMC AND ENERGY PURCHASE COST RESULTS 70
3.5. OTHER ENERGY COSTS 71
3.5.1. Mandatory Renewable Energy Target (MRET) 71
3.5.2. Queensland 13% Gas Scheme 72
3.6. NEMMCO COSTS 74
3.6.1. Participant and FRC fees 74
3.6.2. Ancillary Services charges 74
3.7. OVERALL SUMMARY RESULTS FOR THE COST OF ENERGY 75
3.8. NEM LOAD 76

4. RETAIL COSTS AND MARGINS 77

4.1. CUSTOMER NUMBERS 77
4.2. RETAIL COSTS 77
4.2.1. Categories of retail costs 77
4.2.2. Retail costs for a standalone retail business as against an integrated utility 79
4.2.3. Discussion of fixed and variable components of retail costs 79
4.2.4. Approach to estimating retail costs for the BRCI calculations 81
4.2.5. Submissions to the Authority's Interim Consultation Notice regarding retail operating costs excluding customer acquisition costs 82
4.2.6. Responses to submissions to the Authority's Interim Consultation Notice regarding retail operating costs excluding customer acquisition costs 82
4.2.7. Conclusion on retail operating costs excluding customer acquisition costs 83
4.2.8. Customer acquisition costs 84
4.2.9. Summary of the results for retail costs 92
4.3. RETAIL MARGIN 93

4.3.1. Terminology 93
4.3.2. Conclusion on retail margin for 2008-09 94
4.3.3. Conclusion on retail margin for 2009-10 95

5. NETWORK COSTS AND OTHER RELEVANT COSTS 96

5.1. NETWORK COSTS 96
5.2. OTHER RELEVANT COSTS 96

6. RESULTS 97

APPENDIX A : OUTLINE OF CONSULTANCY FROM THE TERMS OF REFERENCE 98

APPENDIX B : APPROACHES USED TO DETERMINE ALLOWABLE ENERGY COSTS IN OTHER JURISDICTIONS 99

B.1 VICTORIA 99
B.2 SOUTH AUSTRALIA 100
B.3 NEW SOUTH WALES 101
B.3.1 NSW 2004 Price Determination 101
B.3.2 NSW 2007 Price Determination 102

APPENDIX C : ALTERNATIVE APPROACH TO ESTIMATING THE QUEENSLAND LOAD FOR 2008 FOR CALCULATION OF THE LRMC 104

C.1 OVERVIEW 104
C.2 STATISTICAL APPROACHES 104
6.1.1. Time independent forecasting methodologies 104
6.1.2. Time-ordered forecasting methodologies 106
C.2.1 Advanced statistical techniques 107
C.3 AN ALTERNATIVE APPROACH 108
C.3.1 Description of the alternative approach 109
C.3.2 Results 109

APPENDIX D : CEMOS MODEL 116

D.1 CEMOS MODELLING FRAMEWORK 116
D.1.1 Long-term generation capacity expansion and dispatch 117
D.1.2 Generation offer strategy using CONE 118
D.1.3 Short term dispatch analysis using STEMM 119
D.2 CALIBRATION OF CEMOS 121
D.3 RECENT MAJOR APPLICATIONS OF CEMOS 123

APPENDIX E : GRAPHS OF D-CYPHA TRADE PRICES USED IN ESTIMATING THE COST OF PURCHASING ENERGY IN 2009-10 126

E.1 FLAT SWAP CONTRACT PRICES 126
E.1.1 Q3 2009 – July to September 2009 126
E.1.2 Q4 2009 – October to December 2009 127
E.1.3 Q1 2010 – January to March 2010 128
E.1.4 Q2 2010 – April to June 2010 129
E.2 PEAK SWAP CONTRACT PRICES 130
E.2.1 Q3 2009 – July to September 2009 130
E.2.2 Q4 2009 – October to December 2009 131
E.2.3 Q1 2010 – January to March 2010 132
E.2.4 Q2 2010 – April to June 2010 133
E.3 CAP CONTRACT PRICES (AT $300 CAP) 134
E.3.1 Q3 2009 – July to September 2009 134
E.3.2 Q4 2009 – October to December 2009 135
E.3.3 Q1 2010 – January to March 2010 136
E.3.4 Q2 2010 – April to June 2010 137

APPENDIX F : INPUT ASSUMPTIONS – DATA SHEET 138

F.1 INPUT DATA FOR LRMC CALCULATION 138
F.1.1 Load data 138
F.1.2 Generator capital cost data 141
F.1.3 Generator operating cost data 141
F.1.4 Generator fuel cost data 142
F.1.5 Thermal Efficiency 145
F.1.6 Availability 145
F.1.7 WACC 145
F.1.8 Project life 146
F.1.9 Permit prices 147
F.1.10 Renewable Energy Targets 147

TABLE OF FIGURES

Figure 1: Indicative costs of generating technologies 27

Figure 2: Indicative price duration curve 28

Figure 3: 2008 calendar year load for Queensland 40

Figure 4: 2008 calendar year load for New South Wales 40

Figure 5: 2008 calendar year load for South Australia 41

Figure 6: 2008 calendar year load for Victoria 41

Figure 7: 2008 calendar year load for Tasmania 42

Figure 8: Half-year LDC for Queensland – comparison of the first half of 2007 and 2008 43

Figure 9: Full-year LDC for Queensland – comparison of 2007 and 2008 43

Figure 10: Permit prices used in the LRMC modelling 45

Figure 11: 2009-10 Queensland load duration curve – peak 65

Figure 12: 2009-10 Queensland load duration curve – off-peak 66

Figure 13: Queensland Load Shape 111

Figure 14: New South Wales Load Shape 112

Figure 15: South Australia Load Shape 113

Figure 16: Tasmania Load Shape 114

Figure 17: Victoria Load Shape 115

Figure 18: Interaction of CEMOS components 116

Figure 19: Average prices 2006/07 ($/MWh) 122

Figure 20: CEMOS vs. actual NEM spot price duration curve for Queensland 123

Figure 21: d-cypha Trade prices for Queensland flat swap contracts for Q3 2009 – July to September 2009 126

Figure 22: d-cypha Trade prices for Queensland flat swap contracts for Q4 2009 – October to December 2009 127

Figure 23: d-cypha Trade prices for Queensland flat swap contracts for Q1 2010 – January to March 2010 128

Figure 24: d-cypha Trade prices for Queensland flat swap contracts for Q2 2010 – April to June 2010 129

Figure 25: d-cypha Trade prices for Queensland peak swap contracts for Q3 2009 – July to September 2009 130

Figure 26: d-cypha Trade prices for Queensland peak swap contracts for Q4 2009 – October to December 2009 131

Figure 27: d-cypha Trade prices for Queensland peak swap contracts for Q1 2010 – January to March 2010 132

Figure 28: d-cypha Trade prices for Queensland peak swap contracts for Q2 2010 – April to June 2010 133

Figure 29: d-cypha Trade prices for Queensland $300 cap contracts for Q3 2009 – July to September 2009 134

Figure 30: d-cypha Trade prices for Queensland $300 cap contracts for Q4 2009 – October to December 2009 135

Figure 31: d-cypha Trade prices for Queensland $300 cap contracts for Q1 2010 – January to March 2010 136

Figure 32: d-cypha Trade prices for Queensland $300 cap contracts for Q2 2010 – April to June 2010 137

Figure 33: Queensland's 2009-10 tariff year LDC compared to the 2008-09 tariff year LDC 140

TABLE OF TABLES

Table 1: Forecast changes in CPI used in this report 20

Table 2: Forecast changes in WPI used in this report 20

Table 3: Summary of approaches used to calculate energy cost in other jurisdictions 24

Table 4: Permit prices used in the LRMC modelling 44

Table 5: Calculating NEM sent-out generation as a % of total Australian sent-out generation 46

Table 6: Annual Renewable Energy Targets 47

Table 7: Capital costs used in the 2009-10 tariff year LRMC calculation 49

Table 8: Coal fuel costs used in the 2009-10 tariff year LRMC calculation 50

Table 9: Victoria gas spot prices (real 2006-07 $/GJ) 50

Table 10: CCGT fuel costs used in the 2009-10 tariff year LRMC calculation 51

Table 11: OCGT fuel costs used in the 2009-10 tariff year LRMC calculation 52

Table 12: FOM and VOM used in the 2009-10 tariff year LRMC calculation 53

Table 13: Thermal efficiency and auxiliary factors used in the 2009-10 LRMC calculation 54

Table 14: Availability factors used in the LRMC modelling 54

Table 15: WACC assumptions 55

Table 16: The LRMC of energy 58

Table 17: Comparison of installed capacity and generation in Old MRET only and New RET only cases 59

Table 18: Comparison of installed capacity and generation in New RET & 10% carbon reduction price with New RET & 20% carbon reduction price cases 60

Table 19: Criteria used to purchase hedge contracts for Queensland load 63

Table 20: Average spot market prices for each quarter ($/MWh) 67

Table 21: Average costs of energy contracts for each quarter ($/MWh) 69

Table 22: Average Marginal Loss Factor (MLF) 70

Table 23: Energy purchase costs 70

Table 24: Energy cost component of BRCI 71

Table 25: Estimated NEM fees ($/MWh) 74

Table 26: Summary of the cost of energy ($/MWh) 75

Table 27: Summary of retail costs ($/customer) 92

Table 28: Draft BRCI calculation results 97

Table 29: Selected applications of CEMOS 123

Table 30: Details of the 40 load blocks for Queensland in the 2009-10 tariff year LRMC calculation 139

Table 31: Capital costs used in the 2009-10 tariff year LRMC calculation 141

Table 32: FOM and VOM used in the 2009-10 tariff year LRMC calculation 141

Table 33: Coal fuel costs used in the 2009-10 tariff year LRMC calculation 142

Table 34: Victoria gas spot prices (real 2006-07 $/GJ) 143

Table 35: CCGT fuel costs used in the 2009-10 tariff year LRMC calculation 143

Table 36: OCGT fuel costs used in the 2009-10 tariff year LRMC calculation 144

Table 37: Thermal efficiency and auxiliary factors used in the 2009-10 LRMC calculation 145

Table 38: Availability factors used in the LRMC modelling 145

Table 39: WACC assumptions 146

Table 40: Permit prices used in the LRMC modelling 147

Table 41: Calculating NEM sent-out generation as a % of total Australian sent-out generation 147

Table 42: Annual Renewable Energy Targets 148

1. INTRODUCTION

1.1. BACKGROUND

With the introduction of Full Retail Competition (FRC) in the Queensland energy market on 1 July 2007, licensed electricity retailers have been able to offer market contracts to all electricity customers. For those customers who do not enter into a market contract, ***notified prices*** apply. In addition, at the conclusion of a market contract, customers are able to revert to a notified price for their electricity supply.

Prior to 1 July 2007, the notified prices that applied to non-contestable customers were set by the Minister for Mines and Energy (the Minister), and in recent years these prices have increased each year in line with CPI. With the introduction of FRC, a new method of adjusting notified prices applies each year, as set out in amendments to the *Electricity Act 1994* (the Act).[1] Commencing in 2007-08, changes are made to the notified prices with reference to movements in the Benchmark Retail Cost Index (BRCI).

Because the notified prices are to be varied at 1 July each year in accordance with movements in the BRCI, in the first year (2007-08) the BRCI had to be calculated for the two tariff years 2006-07 and 2007-08 to enable notified prices to be in place from 1 July 2007.[2]

When the BRCI was calculated to enable notified prices to be reset from 1 July 2008, there was a change in the theoretical framework for calculating the cost of energy since the previous calculation of the BRCI for 2007-08. Therefore, the BRCI for 2007-08 was recalculated using the new theoretical framework that was applied to the calculation of the BRCI for 2008-09.[3]

---

1 These amendments to the Act were incorporated in the *Electricity and Other Legislation Amendment (EOLA) Act 2006*. The EOLA Act can be downloaded from www.legislation.qld.gov.au/LEGISLTN/ACTS/2006/06AC060.pdf.

All references in this report to requirements in the Act for the calculation of the BRCI are based on Reprint No. 7A of the Act, as in force on 1 July 2008, sourced at www.legislation.qld.gov.au/LEGISLTN/CURRENT/E/ElectricA94.pdf.

2 Various documents relating to the initial setting of notified prices from 1 July 2007, including previous CRA reports, have been published on the Authority's website at www.qca.org.au/electricity-retail/NEP/index.php.

3 Various documents relating to the re-setting of notified prices from 1 July 2008, including previous CRA reports, have been published on the Authority's website at www.qca.org.au/electricity-retail/NEP0809.

This year, as discussed in this report, no change is being proposed to the theoretical framework, and therefore the BRCI is now being calculated only for the one tariff year 2009-10. The results of this calculation of the BRCI for 2009-10 will then be compared with the Authority's previous calculation of the BRCI for 2008-09, which was calculated using the same theoretical framework, in order to set the notified prices that will apply from 1 July 2009.[4]

The Queensland Competition Authority (the Authority)[5] has engaged CRA International Pty Ltd (CRA) to provide assistance in calculating the BRCI for 2009-10.

This report is CRA's First Report on the calculation of the BRCI for 2009-10, and is being released for comment by the Authority. It includes discussion of the approach that has been taken to the development of the various components of the BRCI and the data sources that have been used, as well as a draft calculation of the BRCI and its component parts.

1.2. ORGANISATION OF THIS REPORT

The remainder of this report is structured as follows:

- Section 2 discusses the requirements for calculation of the BRCI, as set out in the legislative and regulatory framework documentation, as well as the Government policy objectives within which the BRCI is expected to operate. It also documents the scope of work undertaken in this assignment, and inputs that were received from the Authority (including those that arose within the Authority's consultation process). It discusses the timetable for the preparation of the 2009-10 BRCI and its implications for the calculation, and addresses certain key data definitions and values.
- Sections 3, 4 and 5 discuss in detail the cost components of the BRCI – these being the cost of energy, retail costs and margins, network costs, and other relevant costs.
- Section 6 summarises the results of the calculation of BRCI.
- Appendix A contains the Outline of Consultancy from the Terms of Reference for this study.
- Appendix B summarises approaches that have been used to determine allowable energy costs in other jurisdictions in the National Electricity Market (the NEM).

4 The Authority is publishing information relating to the re-setting of notified prices from 1 July 2009 on its website at www.qca.org.au/electricity-retail/NEP0910.

5 Queensland legislation refers to the Authority as the *pricing entity* in regard to the Authority's responsibilities that are relevant to the calculation of the BRCI.

- Appendix C contains an alternative approach to estimating the Queensland load for calendar year 2008, compared to the approach that is described and used in the main body of this report.
- Appendix D contains background information on CRA's proprietary model CEMOS, which has been used in our calculation of energy costs.
- Appendix E provides graphs of d-cypha Trade prices that have been used in our estimation of the cost of purchasing energy.
- Appendix F contains details of the input assumptions we have applied in our calculation of the BRCI.

2. THE REQUIREMENTS FOR CALCULATION OF THE BRCI

The Minister has delegated to the Authority the responsibility for calculating the BRCI for Queensland. The *Electricity Regulation 2006* (the Regulation) provides guidance to the Authority on how the BRCI should be determined, and also sets out the requirements for the consultative process that the Authority must undertake in its determination of the BRCI.[6] Thus all of the following need to be taken into account in determining the BRCI:

- The Act;
- The Regulation; and
- The Certificate of Delegation from the Minister.[7]

The impacts that each of these instruments has on various aspects of CRA's assistance to the Authority in the calculation of the BRCI are set out in this section of the report.

2.1. CALCULATION OF THE BRCI AS BENCHMARK RETAIL COST PER UNIT OF NET LOAD

The Act sets out that the BRCI ("B") for the State for a particular year is calculated and expressed in ¢/kWh by dividing the total benchmark retail cost of electricity for the State for the year ("R") by the total NEM load of the State for the relevant tariff year ("L"):

B = R / L

Where:

B is the BRCI for the year;

R is the total benchmark retail cost for the year; and

L is the total NEM load of the State for the year.

2.2. THE TOTAL BENCHMARK RETAIL COST

The total benchmark retail cost – the numerator of the BRCI calculation equation – is to be expressed in cents,[8] and comprises the following benchmark retail cost elements:

---

6 All references in this report to requirements in the Regulation for the calculation of the BRCI are based on Reprint No. 2D of the Regulation, as in force on 1 July 2008, sourced at www.legislation.qld.gov.au/LEGISLTN/CURRENT/E/ElectricR06.pdf.

7 The current Certificate of Delegation from the Minister is dated 11 March 2008. Copies of this Certificate of Delegation and an accompanying letter from the Minister have been placed on the Authority's website at www.qca.org.au/files/E-NEP0809-LtrMinister-BRCISub.pdf. This Certificate of Delegation revokes the previous Certificate of Delegation which can be found on the Authority's website at www.qca.org.au/electricity-retail/NEP.

- The cost of energy;
- Network costs;
- Retail costs; and
- Any other relevant costs.

The way in which each of these components is defined is set out in turn below. Each component is also subject to any relevant provision under the Regulation.

2.2.1. Cost of energy

The cost of energy must reflect the pricing entity's view of the likely total of the costs to be incurred during the relevant tariff year to purchase energy to supply all of the NEM load of the State for the relevant tariff year. There is no allowance made for weather normalisation or any other normalising adjustments to be made for exceptional circumstances that may have occurred in the relevant tariff year.

This view is required to be based on the Long Run Marginal Cost (LRMC) of energy in the part of the State connected to the national grid, and must include the costs of retailers' compliance with the Queensland 13% Gas Scheme and the Commonwealth Mandatory Renewal Energy Target (MRET) Scheme.

The LRMC must take into account the most efficient combination of generating plant to supply all of the NEM load of the State for the relevant year.

The Regulation prescribes that the approach to estimating the LRMC of energy for each tariff year must be a theoretical framework that complies with the following principles:

- It is generally recognised and understood in economic theory;
- The application of the theoretical framework results in a cost per unit of electricity expressed in $/MWh;[9]
- The LRMC is calculated to meet the demand profile (called the NEM load shape) formed over each half-hour electricity trading period of the State for the previous calendar year;[10] and

8 Given that B = R / L, B is measured in ¢/kWh, and L is measured in kWh, it follows that R must be measured in cents. The Act states instead that the benchmark retail cost is expressed in ¢/kWh, but this cannot be correct.

9 As stated in section 2.1 above, as a component of total benchmark retail cost, the cost of energy needs to be in cents. Therefore the cost of electricity in $/MWh needs to be divided by 10 to give ¢/kWh, then multiplied by the total NEM load in kWh to give the required cost of energy in cents.

10 The Regulation thus requires that the LRMC calculation for 2009-10 shall be based on the NEM load shape for Queensland in 2008.

- There is no double counting of costs of meeting the Queensland 13% Gas Scheme or the Commonwealth Mandatory Renewal Energy Target (MRET) Scheme.

The Regulation also prescribes that the theoretical framework must take into account ancillary services needed to meet the NEM load of the State for the relevant tariff year.

The theoretical framework must be the same (or substantially the same) from tariff year to tariff year, unless there is a clear reason for change. If there is a change in the framework, the BRCI for the previous year should be re-calculated to determine what it would have been, based on the changed framework.

2.2.2. Network costs

Network costs are defined in the Act to be the pricing entity's view of the likely total revenue requirements for the relevant year for transmission and distribution entities in the State.[11]

The current Certificate of Delegation sets a requirement that in calculating the network cost component of the BRCI the Authority must apply the Aggregate Annual Revenue Requirement (AARR), without undertaking any smoothing of the AARR.[12]

2.2.3. Retail costs

Retail costs are to reflect the pricing entity's view of the likely cost of providing customer retail services to Queensland customers connected to the national grid, based on an efficient entity carrying on an electricity retail business that meets all of the following criteria:

- It is carried on separately from any other business;
- It has a significant market share of the State's electricity retail business;
- It provides customer retail services to a cross-section of customers; and
- It earns a reasonable retail margin.

11 Though this BRCI component is titled "network costs", the values that are to be used to calculate this BRCI component are revenue requirements which do not constitute the actual costs incurred by retailers for transmission and distribution services in any given year.

12 The previous Certificate of Delegation did specify smoothing of Ergon Energy's AARR in the calculation of network costs, but the current Certificate of Delegation specifically states that such smoothing should not now be undertaken.

The Regulation prescribes that in forming a view of the likely cost of providing customer retail services the pricing entity must assume that the retail entity under consideration has a proportion of customers, separated into customer types defined by their consumption level within particular consumption bands, which is substantially the same as the proportion for the bands for the whole Queensland customer base.

The Regulation gives as an example:

- 88% of the customer base comprises domestic customers with annual consumption less than 100 MWh;
- 11% of the customer base comprises business customers with annual consumption less than 100 MWh;
- 0.5% of the customer base comprises business customers with annual consumption between 100 and 200 MWh; and
- The remaining 0.5% of the customer base comprises business customers with annual consumption more than 200 MWh.

The Regulation further prescribes that the pricing entity must consider the following cost categories for the provision of customer retail services:

- Billing;
- Customer call centres;
- Credit management;
- Energy trading activities;
- Corporate overheads, including, for example, treasury functions, human relations and facilities management;
- Information technology systems; and
- Any other cost category the pricing entity considers reasonable.

As was the case in regard to the cost of energy, if the framework is changed from one tariff year to the next, the pricing entity must calculate what the BRCI for the previous year would have been based on the changed framework – this is necessary so that the BRCI calculations for consecutive years can be compared meaningfully.

2.2.4. Other relevant costs

The Act defines these as any other relevant costs that the Authority considers to be relevant.

2.3. WORKING OUT THE NEM LOAD

The NEM load is the denominator of the BRCI calculation equation.

As defined in the Act, the NEM load (which is to be expressed in kWh) is the pricing entity's view of the sum of the total loads supplied at each ***transmission connection point*** to a supply network within the State, as adjusted for any matter prescribed under a regulation. The term ***transmission network connection point*** in the Act refers to a Queensland transmission network connection point as defined under the National Electricity Rules. The NEM load therefore should include only the energy delivered from the transmission connection network that flows through the distribution system to customers, and should *exclude* any end-user load that is directly connected to the transmission system.

Attachment B, *Methodology of Annual Indexation of Notified Prices*, to the Minister's letter and original Certificate of Delegation of 16 March 2007 stated in section 2.1 – *Working out the NEM Load*:

> *For consistency purposes, the period for measuring 'L" should be the same from year to year. Therefore, NEM Load for a prospective tariff year will be the twelve months of data to 31 December in the calendar year immediately prior. Egg for tariff year 2007/08 NEM load data will be measured from calendar year 2006.*

Thus, for the calculation of the BRCI for 2009-10, the NEM Load is measured from calendar year 2008.

2.4. FIXING OF FUTURE PRINCIPLES

The Act enables the pricing entity to fix principles to apply for a benchmark retail cost element. For example, it may fix a principle that, over a period of several years, retail costs will increase each year by the rate of increase in CPI. However, the current Certificate of Delegation from the Minister specifically states:

> *This delegation does not include the power to fix principles under section 95 of the Act.*

On that basis, the possible application of fixed principles is not considered in this report.

2.5. INPUTS FROM THE AUTHORITY'S CONSULTATION PROCESS

On 2 July 2008, the Authority released an Interim Consultation Notice on the calculation of the BRCI for 2009-10.[13] In response, the Authority received the following submissions, which are listed below in the order in which they are listed on the Authority's website:

---

13 *Benchmark Retail Cost Index for Electricity: 2009-10 – Interim Consultation Notice*, Queensland Competition Authority, July 2008.

- AGL (Jul 08) (PDF, 158KB)
- Australian Power and Gas (Jul 08) (PDF, 789KB)
- EnergyAustralia (Jul 08) (PDF, 322KB)
- Ergon Energy (Jul 08) (PDF, 63KB)
- Integral Energy (Jul 08) (PDF, 156KB)
- Origin Energy (Jul 08) (PDF, 146KB)
- Queensland Consumers' Association (Jul 08) (PDF, 53KB)
- TRUenergy (Jul 08) (PDF, 37KB)
- Queensland Council of Social Service (Jul 08) (PDF, 108KB)

The issues raised in these submissions are discussed where relevant in the appropriate sections of this report.

Issues raised in submissions that do not relate to CRA's scope of work in calculating the BRCI are not considered further in this report, and are left for the Authority to consider in its consultation and decision processes as appropriate.

As discussed in section 1.1 above, when the BRCI was calculated to enable notified prices to be reset from 1 July 2008, there was a change in the theoretical framework for calculating the cost of energy since the previous calculation of the BRCI for 2007-08. Therefore, the BRCI for 2007-08 was recalculated using the new theoretical framework that was applied to the calculation of the BRCI for 2008-09. This year, as discussed in this report, no change is being proposed to the theoretical framework, and therefore the BRCI is now being calculated only for the one tariff year 2009-10. The results of this calculation of the BRCI for 2009-10 will then be compared with the Authority's previous calculation of the BRCI for 2008-09, which was calculated using the same theoretical framework, in order to set the notified prices that will apply from 1 July 2009.

Many of the submissions to the Authority's Interim Consultation Notice raised issues regarding various aspects of how to re-calculate the BRCI for the previous tariff year where there is a change in the theoretical framework. Because the BRCI is now being calculated only for the one tariff year 2009-10, issues raised in submissions regarding re-calculation of the BRCI for the previous tariff year are not discussed in this report.

2.6. CRA'S TERMS OF REFERENCE FOR THIS STUDY

Appendix A contains the Outline of Consultancy from the Terms of Reference for this study. We note in particular the following:

> *The Authority established the framework for determining each element of the benchmark retail cost index in its May 2008 Final Decision on the 2008-09 BRCI. It is currently expected that the same framework will be adopted in calculating the BRCI for 2009-10. Given the shortened timeframe for this assessment, it is currently not anticipated that there will be any changes to the method of calculation, and therefore no requirement to recalculate the BRCI for 2008-09.*

We are at the moment working on the basis of the current expectation that was specified as above in our Terms of Reference, i.e. that the framework that the Authority will adopt in calculating the BRCI for 2009-10 will be that which the Authority adopted in its May 2008 Final Decision on the BRCI for 2008-09.[14] In our final advice to the Authority on the calculation of the BRCI for 2008-09,[15] we provided a range of possible calculation methods and frameworks, from which the Authority made its selection of one particular calculation method in its Final Decision. Because we are not aware of any additional information having been put forward that has materially changed the basis on which the Authority made that selection, the BRCI calculations for 2009-10 in this report are based on the same framework and method that the Authority chose to use in its Final Decision for 2008-09. Specifically:

- In the calculation of the LRMC of energy, trended capital and fuel costs are used rather than year-to-year costs; and
- In the calculation of the LRMC of energy, and in the calculation of energy purchase costs, our modelling is based on full Queensland load, including the directly connected customers in the State.

2.7. DATA PROVIDED BY THE AUTHORITY

The Authority has provided (or will provide) to CRA the following data for the purposes of this assignment:

- The NEM load for the State for part of the calendar year 2008. As stated in section 2.3 above, this NEM load should include only the energy delivered from the transmission connection network that flows through the distribution system to customers, and should exclude any end-user load that is directly connected to the transmission system;
- Estimated total number of customers in the State, by customer size, for 2009-10; and

14 *Benchmark Retail Cost Index for Electricity: 2008-09*, Final Decision, Queensland Competition Authority, May 2008.

15 *Calculation of the Benchmark Retail Cost Index for 2007-08 and 2008-09*, Addendum, CRA, 26 May 2008.

- AARR figures as required for the calculation of the "network costs" for the BRCI for 2009-10 as described in section 2.2.2 above. As noted above, these are revenue requirements and are not the costs actually incurred by retailers for transmission and distribution services in any given year.

At the time of finalisation of this First Report, due to some of the data not yet being available, the Authority had provided:

- Actual NEM load for the State for the period 1 January 2008 to 12 July 2008, but not for any later dates in 2008;
- Estimated customer numbers for 2008-09, and not for 2009-10; and
- Estimated AARR for 2009-10.

CRA's methods of data estimation for the purposes of its draft calculations are discussed in the appropriate parts of sections 3, 4, and 5 of this report.

2.8. QUEENSLAND GOVERNMENT POLICY OBJECTIVE

The current Certificate of Delegation sets a requirement that the Authority must consider a policy objective of the Queensland Government when exercising the delegated powers and functions, which consists of the following two policy intents:

- The annual indexation of electricity tariffs by the index should ensure that existing retail headroom in the tariffs at the date of the delegation[16] remains relatively stable (although not necessarily the same from year to year); and
- The policy of enabling small market customers to revert to notified prices should not result in a retail entity providing customer retail services to non-market customers at a loss.

A letter from the Minister to the Chairman of the Authority which accompanied the previous (now revoked) delegation provided the following points of clarification:

- In relation to the first policy intent, headroom refers to the difference between the cost of supply and the current tariff level; and
- The second policy intent is to apply where retailers have acted reasonably in providing retail services to customers. It is not intended to protect retailers from any losses attributable to an incorrect assessment of the profitability of a customer or a change in the circumstances of the customer or retailer that is not related to changes in the cost of electricity supply reflected in the BRCI.

16 That is, 11 March 2008. This constitutes a change from the previous statement of the policy objective in the original delegation, which referred to ensuring that existing retail headroom in the tariffs at the date of that original delegation (16 March 2007) remained relatively stable.

The cover letter to the current delegation provided the following additional guidance:

> *The Queensland Government's objective is to foster competition in the energy market so that the economy and customers derive the benefits of a competitive energy sector. Efficient and sustainable energy pricing is essential to meeting these objectives, particularly in the face of the significant growth currently occurring in south-east Queensland.*
>
> *In line with achieving efficient and sustainable energy pricing, the Government wishes to ensure that only genuine cost increases are passed on to consumers through the application of the BRCI.*

Since its inception, the calculation of the BRCI has conformed to the requirements that are prescribed in the Act and in the Regulation, rather than on the basis of actual retailer headroom. Therefore, the analysis that has been undertaken has not extended to consideration of whether a change in tariffs based on the change in the BRCI as calculated would meet the Government's policy objective.

The current framework for calculating the BRCI does not include a method for assessing whether the Government's policy objective is met, and nor does it prescribe how to adjust the BRCI if any part of the policy objective is not met.

Assuming that it would be possible to quantify the extent to which the Government's policy intents are or are not met, it may be possible to amend the BRCI framework as prescribed in the Act and Regulation to increase the extent to which the policy intents would be met in any calculation undertaken under the new framework.

To measure the extent to which the policy intents are met would require substantially more work, and application of the results to the calculation method for the BRCI would clearly constitute a change in framework.

2.8.1. Headroom in the tariffs – the first policy intent

The Government's first policy intent states that the annual indexation of electricity tariffs by the index should ensure that existing retail headroom in the tariffs at the date of the delegation remains relatively stable (although not necessarily the same from year to year).

This policy intent relates to actual headroom in the tariffs, in contrast to the calculation of the BRCI, which as set out in the Act and in the Regulation is based on various theoretical calculations and concepts. As stated above, the Minister has clarified that headroom refers to the difference between the cost of supply and the current tariff level. We suggest that cost of supply refers to the cost of energy and network costs, but does not include retail operating costs, which would more correctly be termed a cost of sales rather than a cost of supply. Thus we suggest that the headroom to which the first policy intent is referring is gross margin rather than net margin. Government policy intent to maintain gross margin rather than net margin would be understandable as it would leave each retailer responsible for managing its retail operating costs separately, and would not license inefficiency. On the other hand, setting tariffs based only on maintaining gross margin without reference to net margin would not enable tariffs to change to take into account any disproportionate changes in retail operating costs.

There are many reasons why the actual headroom in each of the Queensland tariffs may differ from year to year. These include the following:

- The BRCI measures overall changes in costs averaged across the State in proportion to the entire customer base. In contrast, each retailer's portfolio of customers will differ from this average. To the extent that there are differences in the rate of change of costs in different geographic areas and in different customer segments, each retailer's actual headroom and the change in that headroom will differ from year to year.

- On average, each retailer's changes in costs from year to year will differ from the change calculated by the BRCI, because:

  - Actual energy costs are based on hedging strategies, and actual purchase costs are not the same as the theoretical LRMC, though over the longer term changes in actual costs will relate to changes in the LRMC. Actual energy costs will depend almost exclusively on the retailer's hedging position including its degree of vertical integration, transfer pricing policies and degree of spot exposure. LRMC is irrelevant except insofar as the LRMC has some influence on bidding behaviour (for spot purchases) and contract prices. The weighting of the two energy cost factors is a methodological requirement that does not replicate the actual costs that are experienced in the market.

  - Actual network costs incurred by retailers vary between customers and between regions and are not directly proportional to the AARR values that have been prescribed for use in calculating the AARR. Given that in respect of each individual customer the network charges are published and do not vary between retailer, it could be possible (subject to change in the legislation) to reflect retailers' actual network costs rather than the AARR in the BRCI framework.

It is noteworthy also that the headroom available to two retailers each serving customers with exactly the same geographic and usage characteristics in the same timeframe will still in practice differ between the two retailers. Though both retailers would receive the same revenue based on notified prices, and have the same network costs, actual energy costs would undoubtedly differ, because each retailer would have its own unique hedging strategy and contracts for purchase of wholesale electricity. Actual retail costs will also differ depending on each retailer's efficiency, but this is not an issue for the first policy intent if headroom is considered to refer to gross margin rather than to net margin.

From time to time, there may be substantial one-off changes in a retailer's wholesale energy purchase strategy. For example, Origin Energy recently announced that it had entered into a long-term hedging agreement with a Queensland generator that will support the supply of electricity products to Origin Energy customers in Queensland for a minimum of ten years.[17] Without knowledge of Origin Energy's previous / existing hedging arrangements, we do not know how significantly this hedging arrangement will change Origin Energy's cost base, and hence its headroom.

In its submission to the Authority's Interim Consultation Notice, Origin Energy has included a section on Change in Retail Headroom, and this includes an analysis of annual change in headroom in 2007-08 and 2008-09, for residential customers on the regulated tariffs 11, 31 and 31 on the Energex network. Origin Energy's calculations include taking into account actual revenues and network costs for these customers. The results show a lessening of headroom in both 2007-2008 and 2008-09, based only on the treatment of the network costs. Origin Energy's submission notes the cause of this lessening of headroom: "In other words, the estimated cost of supplying electricity for each residential customer in the Energex area was well above the BRCI escalation and subsequent retail tariff change. As a result, energy retailers are seeing a $25-$40 reduction in headroom over a two year period."[18]

Origin Energy's explanations of its calculations clearly show that Origin Energy is interpreting headroom to mean net margin rather than gross margin. On the other hand, AGL's submission to the Interim Consultation Notice includes a graph that illustrates movement in gross margin,[19] suggesting that AGL is interpreting this to be the headroom referred to in the Government's first policy intent.

---

17 *Origin secures long term Queensland electricity hedge*, Origin Energy media release, 23 July 2008, available at www.originenergy.com.au/news/news_detail.php?pageid=82&newsid=935.

18 Origin Energy submission to the Authority on the Interim Consultation Notice for the BRCI 2009-10, July 2008, page 16.

19 AGL submission to the Authority on the Interim Consultation Notice for the BRCI 2009-10, July 2008, page 8.

A further difference of interpretation between AGL and Origin Energy is in regard to whether the Minister's clarification of the definition of headroom should refer to the actual difference between the cost of supply and the current tariff level measured in $/customer, or should be measured as a percentage of revenue. With rising tariffs and rising average consumption per customer, customers' average annual bills will rise, and headroom that is maintained in $/customer would still be eroded if measured as a percentage of revenue. While Origin Energy seems to be seeking that headroom measured in $/customer should be maintained, AGL seems to be seeking to measure a different outcome, which is whether headroom is maintained as a percentage of revenue.

The lessening of headroom results because the network cost component of the BRCI is calculated only by reference to the annual change in the AARR of the distributors across Queensland, and not by reference to the actual network costs, the latter being the approach that has been taken in the setting of standard (default) tariffs in other Australian jurisdictions. If the approach to the setting of annual tariff changes in Queensland were to change to be based on changes in actual network charges rather than on the annual change in the BRCI, this cause of change in headroom could be eliminated. However, the legislative and regulatory framework specifies basing the network costs component of the BRCI on annual changes in the AARR rather than on annual changes in actual network charges, so this is not an easy change to make. Actual network charges differ across the State whereas the retail tariffs are "postage stamped" rather than being individually cost-reflective.

The analysis of headroom undertaken by Origin Energy is based on the Authority's calculations for changes in energy costs and retail costs for the BRCI calculations as a proxy for the actual value of these cost components. Origin Energy notes that in several places in its Addendum Report CRA gave a range of options for how some components of the BRCI could be calculated for 2007-08 and 2008-09, and the Authority's choice from these options has also affected retailers' headroom.

Origin Energy does not include in its calculation of headroom any information on the degree to which its actual energy costs have changed year-on-year and therefore Origin Energy's actual year-on-year change in headroom cannot be determined with certainty from the information that has been made available. The headroom of other retailers would also differ, depending on their actual energy costs (and retail operating costs if headroom is defined as net margin rather than gross margin).

Origin Energy states that its calculations of headroom only relate to specific regulated tariffs that apply only to residential tariffs on the Energex network, and AGL has stated that wording similar to the Government's policy objective was included in a letter dated 1 November 2007 from the Queensland Government to prospective bidders for the retail business.[20] However, the Government's first policy intent in regard to headroom does not distinguish between tariffs for residential as against business customers, and nor does it distinguish between customers on the Energex network as against the Ergon Energy network. We consider that it is intended to apply to all Queensland electricity customers supplied on notified prices, and not just those that were included in the Government's sale of the retail businesses of Sun Retail and Powerdirect Australia.

The legislative and regulatory framework requires the results of the annual BRCI calculations to be applied uniformly to notified prices across Queensland. To the extent that retailers' cost of supply, and particularly network charges, do not change uniformly across the state, the process as currently defined will never meet the Government's first policy intent that existing retail headroom in the tariffs at the date of the delegation should remain relatively stable at the individual retail tariff level. If the change in the BRCI were to be an accurate reflection of the overall change in retailers' cost of supply on average year-on-year, then on average the headroom across all electricity supply on notified prices across the whole state would remain relatively stable. However, given the theoretical nature of many aspects of the BRCI calculations, it is by no means guaranteed that the BRCI calculations would result in relatively stable headroom across the state, even on average, and it would require substantial change to the BRCI framework to guarantee achieving that result.

In summary, we concur that there has been no attempt to meet this policy intent of the Queensland Government. While it would be possible to make changes to the framework to include consideration of this policy intent:

- It may require legislative change – for example to reflect retailers' actual network costs rather than the AARR in the BRCI framework;
- It would require substantially more and different analysis as compared to what has been undertaken to date;
- It would have to take into account regional differences across Queensland, which may not sit well with the current "postage stamp" approach to regulated retail tariffs in Queensland; and
- It would have to take into account differences in cost changes between different tariffs (such as comparing single rate tariffs to separate off-peak tariffs, and comparing residential and business tariffs), which would not sit well with the current approach whereby all notified prices change based on a single index value.

20 AGL submission to the Authority on the Interim Consultation Notice for the BRCI 2009-10, July 2008, page 7.

Further, whatever changes were made to the BRCI framework, headroom would still differ between retailers based on each retailer's actual energy costs (and differences in each retailer's actual retail operating costs if headroom is considered to be net margin rather than gross margin).

2.8.2. Margins available to retailers serving customers that revert to notified prices – the second policy intent

The Government's second policy intent states that the policy of enabling small market customers to revert to notified prices should not result in a retail entity providing customer retail services to non-market customers at a loss.

There is no clarification as to what is meant by serving customers "at a loss". We suggest that it would mean serving customers at negative net margin.

Whether or not this policy intent can be achieved will depend on the characteristics of the customers that revert to notified prices. All other things being equal, the profitability of any customer will vary based on the customer's load profile and volume, use of the retailer's call centre and other communication methods, and payment behaviour.

It may also be that those customers that revert to notified prices would be doing so because, for whatever reason, retailers find they can no longer supply them profitability at prices at or below the notified prices. In those cases, the only way to supply those customers on notified prices may be to supply them at a net margin that is below that which the retailer would normally consider to be reasonable, or indeed to supply them at a loss. This position could arise because actual costs of supply differ widely across Queensland – due to differences in network costs – but the BRCI is calculated based on state-wide averages, and not at the individual customer level.

It is difficult to see how the extent that the second policy intent is met could ever be evaluated robustly on a prospective basis. Possibly, retailers might be able to make available sufficient data to enable an analysis to be undertaken of the characteristics of customers reverting to notified prices, on a retrospective basis. If the costs of the retailers serving those customers were also known, or could be estimated with reasonable accuracy, it should then be possible to evaluate whether the retailer was serving those customers at a loss.

As noted above, a letter from the Minister to the Chairman of the Authority which accompanied the previous (now revoked) delegation also clarified that the second policy intent is to apply where retailers have acted reasonably in providing retail services to customers. It is not intended to protect retailers from any losses attributable to an incorrect assessment of the profitability of a customer or a change in the circumstances of the customer or retailer that is not related to changes in the cost of electricity supply reflected in the BRCI. On this basis, even if it were shown that customers reverting to notified prices were being served at a loss, before it could be determined that the Government's second policy intent was not being met, it would still be necessary to evaluate and confirm that:

- The retailer acted reasonably in offering the customer a market contract in the first place;
- The retailer correctly assessed the profitability of the customer; and
- The losses are not attributable to a change in the circumstances of the customer or retailer that is not related to changes in the cost of electricity supply reflected in the BRCI.

It is not currently within our terms of reference to undertake an analysis of this nature.

2.9. TIMETABLE TO DETERMINE THE BRCI FOR 2009-10

The Authority's Interim Consultation Notice on the calculation of the BRCI for 2009-10 sets out the following timetable:

- Interim Consultation Notice issued and call for submissions 2 July 2008;
- Submissions on Interim Consultation Notice close 21 July 2008;
- Consultant's first report released for comment 15 August 2008;
- Comments on consultant's first report close 22 August 2008;
- Workshop to be held on consultant's first report 27 August 2008;
- Draft Decision released 26 September 2008;
- Submissions on Draft Decision close 10 October 2008;
- Consultant's second report released for comment 21 October 2008;
- Comments on consultant's second report due 27 October 2008;
- Final Decision by the Authority released and adjusted prices for 2009-10 gazetted by 1 December 2008.

This timetable is being driven by the requirement in the current Certificate of Delegation from the Minister which requires the Authority to calculate the BRCI for 2009-10, apply the annual change in the BRCI to notified prices and publish these prices by 1 December 2008.

As stated in the Authority's Interim Consultation Notice, the Electricity Regulation sets out the consultation process that the Authority must follow in calculating the expected change in the BRCI for the following financial year. While the Authority adopted an extensive consultation process during its assessment of the BRCI for 2008-09, the limited time available to the Authority to complete the calculation of the BRCI for 2009-10 and publish revised prices will limit the extent to which the Authority is able to consider any changes to the method used to calculate the BRCI.

2.10. CUT OFF DATES FOR DATA AND INFORMATION TO BE INCLUDED IN CRA'S REPORTS

In order to meet our obligations to the Authority and thus enable the Authority to meet its timetable as set out in section 2.9 above, we have agreed with the Authority that for this First Report we will take into account data and information available as at 15 July 2008, and for the Second Report we will take into account data and information available up to 15 September 2008.

In addition, and to the extent possible in the time available, this first report takes into account submissions on the Authority's Interim Consultation Notice that were received by the due date of 21 July 2008, and our second report will similarly to the extent possible take into account submissions on the Authority's Draft Decision.

2.11. INFLATION FORECASTS

Of relevance to the calculation of the BRCI, the Australian Bureau of Statistics (ABS) publishes the Consumer Price Index (CPI) (ABS index 6401.0) and the Wage Price Index (WPI) (ABS index 6345.0) in retrospect for each quarter of the year. These published figures have been used for historical financial periods as appropriate. As at the cut-off date of data and information for this report – 15 July 2008 – the last published ABS data for both CPI and WPI was for the March 2008 quarter.

In some parts of the BRCI calculation, we also need estimates of the change in CPI and the WPI for the remainder of 2007-08, as well as for 2008-09 and 2009-10. These forecasts are discussed below.

2.11.1. Consumer price index (CPI)

The Reserve Bank of Australia (RBA) publishes CPI forecasts in its quarterly *Statement on Monetary Policy*, every February, May, August and November.[21] In this report we are using CPI forecasts from the RBA's *Statement on Monetary Policy* dated May 2008,[22] as shown in Table 1 below.

21 These are available at www.rba.gov.au/PublicationsAndResearch/StatementsOnMonetaryPolicy/index.html.

22 The Statement dated May 2008 was the last quarterly statement issued before the cut-off date of 15 July 2008 for data and information, as discussed in section 2.10.

Table 1: Forecast changes in CPI used in this report

Period for CPI forecast	Forecast change in CPI for this period
The 12 months to June 2008	4.25%
The 12 months to June 2009	3.5%
The 12 months to June 2010	3%

Source: RBA

2.11.2. Wage price index (WPI)

In our Addendum report on the 2008-09 BRCI we discussed various sources of commentary and data on forecast wage increases. We had previously used pre-election Treasury forecasts dating from November 2007, with which some stakeholders raised concerns, and this was not a source of information that is published and could be used regularly. We found an apparently reliable source to be ANZ's quarterly Economic Outlook[23] – this publication gave results that matched the pre-election Treasury forecasts and which matched other non-quantified commentary. In this report we are using WPI forecasts from the ANZ's Economic Outlook for the September quarter 2008, which was published on 15 July 2008,[24] as shown in Table 2 below.

Table 2: Forecast changes in WPI used in this report

Period for WPI forecast	Forecast change in CPI for this period
The 12 months to June 2008	4.4%
The 12 months to June 2009	4.4%
The 12 months to June 2010	3.7%

Source: ANZ

2.12. CONSEQUENCES OF THE EARLIER TIMETABLE

As discussed in section 2.6 above, we are working on the basis that the framework that the Authority will adopt in calculating the BRCI for 2009-10 will be that which the Authority adopted in its May 2008 Final Decision on the BRCI for 2008-09.

23 Published at www.anz.com/aus/corporate/Economic-Research-And-Publications/Economic-Research/Economic-Outlook/default.asp.

24 The Economic Outlook for the September 2008 quarter was the last quarterly issue published before the cut-off date of 15 July 2008 for data and information, as discussed in section 2.10.

However, as can be seen from the timetable set out in section 2.9 above, the Authority is required to release its Final Decision on the BRCI for the tariff year 2009-10 and gazette the adjusted prices for 2009-10 by 1 December 2008, which is 7 months before the start of the tariff year, whereas in previous years the Final Decision and gazetted tariffs have been required only 1 to 2 months before the start of the tariff year to which the adjusted prices relate. Clearly, there is much more uncertainty about the quantification of the components of the BRCI when the calculations are done so much earlier than in previous years.

Some of the specific consequences of the earlier timetable are as follows:

- The LRMC calculations for each tariff year are based on the Queensland load for the previous calendar year. Hence the LRMC calculations for the tariff years 2006-07, 2007-08 and 2008-09 were based on the Queensland load for calendar years 2005, 2006 and 2007 respectively, and when each of those calculations was finalised the full Queensland load for the relevant calendar year was available. In contrast, this year the full Queensland load for the calendar year 2008 will not yet be available when the LRMC calculations are finalised. Therefore, this year we are required to perform a new set of calculations that was never previously required: to estimate part of the Queensland load for 2008. A similar issue arises in regard to the NEM load (L) – which excludes the load of directly connected customers – and which is used as the denominator of the main BRCI calculation equation.

- The cost of purchasing energy is based on contract prices in the 24 months up to the start of the tariff year. In previous years, at the time of the Final Decision, most of that price data has been available, but this year a larger proportion of that data will not yet be available and will have to be estimated.

- Similarly, a larger proportion of data for costs of ancillary services and for the costs of Renewable Energy Certificates will need to be estimated as against using actual data, and the same is true for inflation figures, customer numbers and customer churn data.

The actions we are taking as a result of each of these issues are documented in the relevant sections of this report.

3. COST OF ENERGY

This section of the report considers the energy cost component of the BRCI in Queensland. This report section:

- Describes the framework adopted for calculating the cost of energy in Queensland, which involves consideration of both the LRMC and the actual cost of purchasing energy;
- Describes the approaches adopted for determining the LRMC and the actual cost of purchasing energy, and presents the results of the modelling in each case; and
- Describes the other energy related products that a retailer is required to purchase and other related costs that a retailer would incur.

Section 3.7 presents the overall summary results of the modelling that has been undertaken to determine an appropriate allowance for the cost of energy, including the allowances for the other energy-related costs.

Finally, section 3.8 reports the values for NEM load that are being used this year in the BRCI calculations for 2009-10.

3.1. ENERGY COST FRAMEWORK IN QUEENSLAND

Section 92 of the Act describes the framework to which the Authority must adhere when calculating the energy cost component of the BRCI. It states that:

- The cost of energy must reflect the pricing entity's view of the likely total of the costs to be incurred during the relevant tariff year to purchase energy to supply all of the NEM load of the State for the relevant tariff year.
- The view must be based on the pricing entity's most recent estimate of the LRMC of energy in the part of the State connected to the national grid, after taking into account:
  - The 13% gas scheme under chapter 5A; and
  - The scheme under the *Renewable Energy (Electricity) Act 2000* (Commonwealth).
- The estimate must take into account the most efficient combination of generating plant to supply all of the NEM load of the State for the relevant tariff year.

As we noted in our reports in previous years on the calculation of the BRCI for 2006-07, 2007-08 and 2008-09, the requirement in Sub-section 92(1) for the cost of energy to reflect the total (i.e. actual) costs incurred for purchasing energy could be viewed as being inconsistent with the requirement in Sub-section 92(2) that the energy cost be based on the LRMC.

The overall approach we are using to determine the energy cost component of the BRCI for 2009-10 is the same as that which we previously used to calculate the BRCI for 2008-09. The approach takes account of both the LRMC of energy and energy purchase costs as required by Sub-sections 92(1) and 92(2) of the Act. We calculate the LRMC of energy for Queensland's retail load as a greenfield estimate of the cost of supplying the load in that year, and we also calculate the energy purchase costs for the Queensland load based directly on Queensland characteristics. The approach used to calculating the energy purchase costs, which is described in section 3.3 below, is to (a) determine the combination of derivative contracts that a prudent retailer would purchase to manage the risks of purchasing energy for the load, and then (b) calculate the combined cost of purchasing hedge contracts and spot market energy for the load.

Having calculated these two estimates, which are required by the Act to be inputs to the cost of energy, the issue becomes how they can be combined into a single cost of energy for use in the BRCI. Our approach is to apply weightings to the LRMC and purchase cost of energy to determine a blended energy cost. Section 3.4 below discusses the rationale for this approach, and gives the results of its application.

As in previous years, we also include in the energy cost component allowances for ancillary services charges and NEMMCO participant and FRC fees, as well as the costs of compliance with the Mandatory Renewable Energy Target (MRET) and the Queensland 13% Gas Scheme.

While the overall approach remains unchanged, some aspects of the approach and the data that we are using have changed, for the following reasons:

- As discussed in section 2.6 above, in our final advice to the Authority on the calculation of the BRCI for 2008-09, we provided a range of possible calculation methods and frameworks, from which the Authority made its selection of one particular calculation method and framework in its Final Decision. In its Terms of Reference for calculation of the 2009-10 BRCI the Authority stated that it expects that "*the same framework [as used in 2008-09] will be adopted in calculating the BRCI for 2009-10,* [and that] i*t is currently not anticipated that there will be any changes to the method of calculation.* As no additional information has been put forward that has materially changed the basis on which the Authority made that selection, the BRCI calculations for 2009-10 in this report are based on the same framework and calculation method that the Authority chose to use in its Final Decision for 2008-09.

- As discussed in section 2.12 above, the earlier timetable this year has consequences for the calculation of the energy cost component of the BRCI.

- Recent federal government publications have clarified that it is likely that Australia will introduce an emissions trading scheme from around July 2010, which will affect the cost of energy.

- The cost of energy will be affected by changes that are to be made to the existing MRET scheme.

- We have also taken into account comments received in submissions to the Authority's Interim Consultation Notice, as mentioned in section 2.5 above.

Approach used to calculate energy cost in other jurisdictions

It is also worth noting that other jurisdictions have used different methods to calculate the energy cost component of the tariff that will apply to small-volume electricity customers who are not offered or do not choose to take a market offer. These approaches can be viewed as spanning a continuum that ranges from consideration of only the LRMC to consideration of actual costs alone. Appendix B provides a discussion of the approaches used to calculate energy cost in other jurisdictions, and how they differ from the approach used to calculate the energy cost component of the BRCI in Queensland. Table 3 below summarises the approaches in other jurisdictions.

Table 3: Summary of approaches used to calculate energy cost in other jurisdictions

Region	Approach	Comment
New South Wales	LRMC and energy costs modelled separately	IPART considered both the LRMC and energy costs and adopted the energy cost approach because it supports its objective of ensuring that retailers charge prices at cost reflective levels by 2010
South Australia	Energy costs, with the LRMC used as input	ESCOSA used contract and pool purchase costs rather than the LRMC to determine the allowance for energy. The LRMC was modelled and used to determine appropriate pool price scenarios
Victoria	Energy costs	No consideration was given to the LRMC in the analysis, with the energy allowance being based on a benchmarking approach to the costs that a prudent and efficient retailer would be likely to incur in purchasing energy

Source: CRA analysis

The approach taken for calculating the energy cost component of the BRCI as described in this report is most similar to the approach taken by IPART, which uses both the LRMC and actual energy costs to form a view on the appropriate allowance for energy in retail tariffs.

3.2. THE LRMC OF ENERGY

This section defines the LRMC of energy, describes the approach and the data sources that we have used to calculate the LRMC, and provides the results of our analysis.

3.2.1. LRMC considerations and approach

Considerations

The Regulation states that the theoretical framework for determining the LRMC of energy must comply with the following principles:

- It is generally recognised and understood in economic theory;
- The application of the theoretical framework should result in a cost per unit of electricity, expressed in $/MWh, that constitutes the cost of energy; and
- The LRMC of energy should be calculated to meet the demand profile (called the NEM load shape) formed over each half-hour electricity trading period of the State for the previous calendar year.

In selecting the appropriate framework, the following considerations have also been taken into account:

- Single-point estimates of costs are required as inputs to the BRCI; and
- The LRMC of energy must be calculated from a retailer's perspective, i.e. it is the cost of purchasing for a retail load.

Approach

The overall approach we are using to calculate the LRMC of energy for Queensland, as part of the BRCI calculations for 2009-10 is the same as that which was used previously as part of the BRCI calculations for 2007-08 and 2008-09. It has the following features:

- Queensland is treated as part of the NEM rather than as an isolated region;
- The LRMC has been calculated for a greenfield system where the existing generation is removed and the most efficient combination of new plant to meet load is determined;
- The modelling uses a multi-year approach, whereby the LRMC is calculated based on the lowest cost combination of generating plant to meet projected load from the base year; and
- The modelling approach optimises investment across the NEM regions to calculate the optimal portfolio taking into account the characteristics of the existing transmission system.[25]

25 The approach used does not optimise the transmission system, but rather assumes that the transmission system that will be used to deliver the energy generated by the optimised generation system is represented by the existing transmission system and known planned retirements, reinforcements, replacements and extensions.

The Regulation requires that the LRMC be calculated to meet the demand profile formed over each half-hour for the previous calendar year. Therefore, the LRMC for 2009-10 is calculated on the basis of the generation required to meet demand in calendar year 2008. As mentioned in section 2.12 above, the requirement to complete the determination of notified prices for the tariff year 2009-10 by 1 December 2008 means that the data required by the Regulation will not be available in full. For this First Report, actual data for the period from 1 January to 15 July 2008 was available; for our Second Report a further two months of data will be available. An overview of the approach we have adopted for developing a full year of load data to represent the 2008 calendar year is presented in section 3.2.9 below.

3.2.2. Definition of the LRMC

The LRMC is commonly defined as the additional cost of servicing additional demand in the long run. The long run represents the useful service life of new capacity that is required to meet expected incremental demand. Estimations of the LRMC vary in practice, but the intent is broadly the same – to estimate long-run generation system expansion costs. For example, the LRMC can be defined as the average incremental cost from expanding output, or the change or perturbation in costs and quantities from an underlying growth baseline.[26]

When calculating the LRMC of new generation, the costs considered include all costs relevant to the investment decision,[27] including capital recovery costs (depreciation), return on capital investment, taxes, fixed operating and maintenance costs as well as the expected short run operating costs (fuel, water, chemicals) over the relevant life of the asset, at appropriate capacity factors.

The approach that has been adopted calculates the marginal cost of supplying one additional MWh in every hour of the tariff year. This equates to the shadow price of meeting the demand constraint. More specifically, the LRMC for 2009-10 is defined as the cost of supplying one additional MWh in every hour of 2009-10 from a generation system that has been optimised to meet the forecast load and loadshape based on the actual load of CY 2008 and forecast growth in energy and peak demand.

It should be recognised that the least-cost means for meeting that additional increment of load will depend on the specifics of the load shape and the relativities of the capital and fuel costs associated with the available generation (and demand response) options.

---

26 The latter approach has been applied in the water sector (for example by Ofwat and the Essential Services Commission Victoria) with timeframes of approximately 20-25 years.

27 See for example *Fuel Resource, New Entry and Generation Costs in the NEM: Report 2 – Data and Documentation*, ACIL Tasman, draft prepared for NEMMCO, 27 March 2007, p.12.

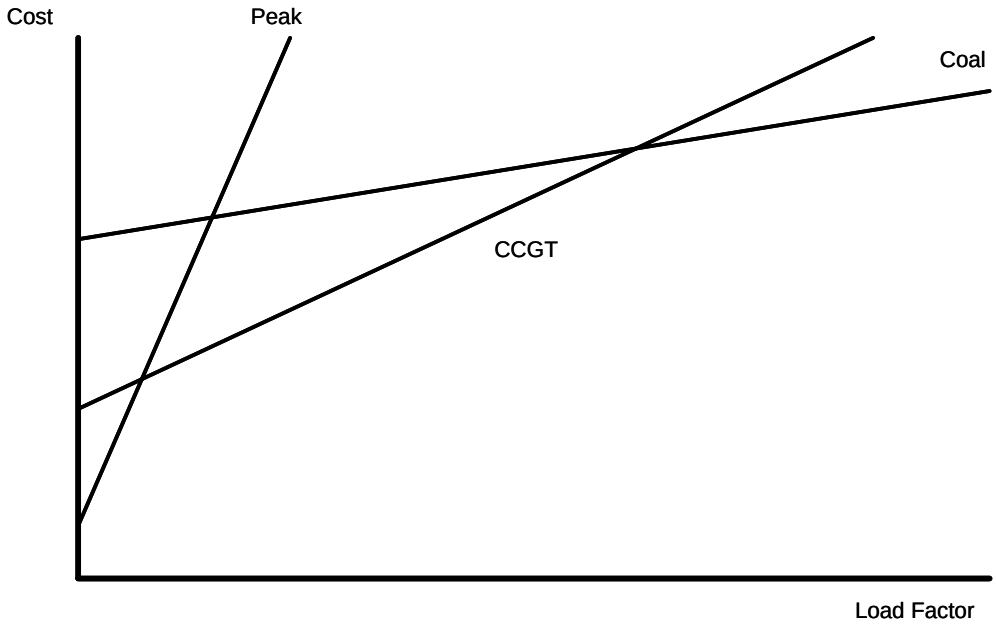
3.2.3. Issues in modelling of the LRMC

The LRMC of generation for a region/system, as the term implies, needs to recognise the cost of meeting an increment of demand in the long run considering both operating and fixed costs associated with new investment.

The load duration curve[28] expected to pertain for the relevant time period has implications for dispatch and investment decisions. That is, the variation of demand across peak and off-peak periods implies a portfolio of peaking, mid-merit and base-load plants that can most efficiently meet the demand rather than a single type of plant.

As load factor varies and as various technologies are used to varying degrees, the total cost changes. Depending on their cost characteristics, some generating technologies are better suited to peaking duty whereas others are best matched for base load duty. These relationships are straightforward, and are summarised graphically in Figure 1 below.

Figure 1: Indicative costs of generating technologies



Source: CRA

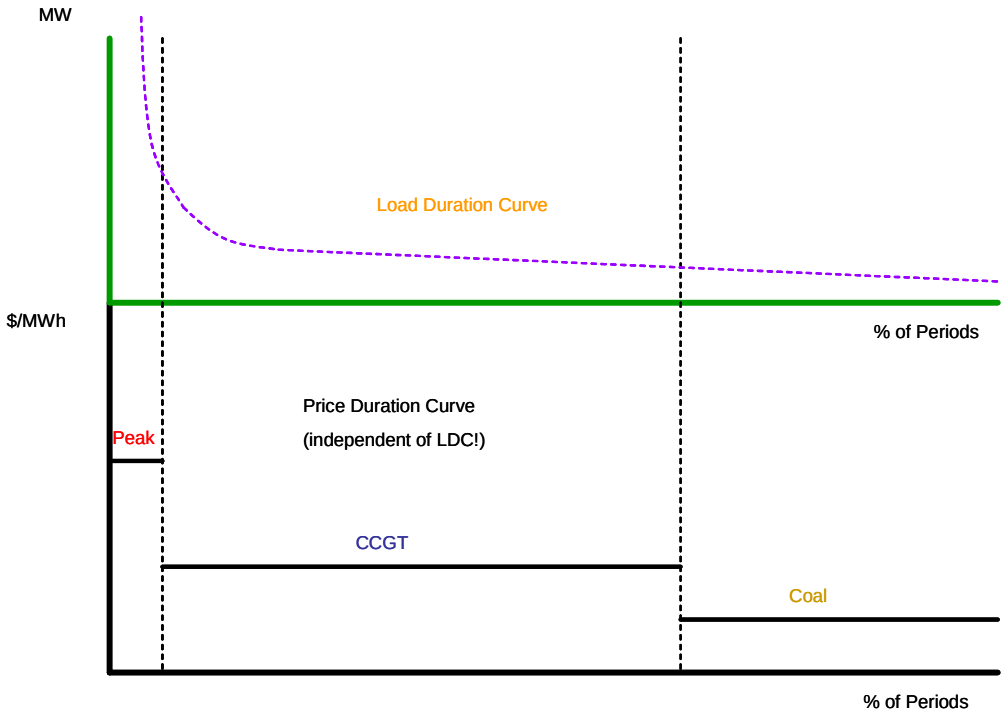
28 The load duration curve (LDC) is a plot of electricity demand on the y-axis against the percentage of time during the year that the load is exceeded on the x-axis. Presenting the load data in this manner provides a view of how 'peaky' demand is in the system. Also, by overlaying the LDC with a chart of plant cost by load factor (Figure 1) it is possible to determine which generating plant type will be the marginal plant to meet particular levels of demand. Assuming plants bid at short run marginal cost (SRMC), for each demand point on the LDC there will be a corresponding price set by the marginal plant. This creates a corresponding price duration curve (PDC). However, given that plants often bid at prices other than SRMC, in practice the PDC may not have a strong correlation with the LDC.

It is then possible to develop the corresponding LRMC by mapping the costs of each "optimal" technology to derive the price duration curve that would support investment in the appropriate technology mix, as shown in Figure 2 below.

Investment and dispatch should be optimal; i.e. the portfolio of investment decisions and dispatch decisions should meet demand at least cost. A least-cost investment and dispatch plan also implies that the plants built to meet demand in the long term are revenue sufficient (or revenue adequate) in that the revenue earned by the plants is equal to total system cost.

The definition implies long-term supply-demand equilibrium of the system. In reality different technologies are likely to be either in excess or deficit supply in the system relative to the optimal level. As a result, the year-on-year marginal cost for the system may vary substantially from the long-term equilibrium level. For example, if there is surplus base-load capacity, an incremental MWh during this period may not incur any incremental capital cost, whereas deficit peaking capacity may result in a very high marginal cost of supply during peak periods.

Figure 2: Indicative price duration curve



Source: CRA

Policy constraints and/or the physical availability of resources may restrict investment and dispatch decisions. Relevant examples include minimum gas generation requirements, minimum renewable generation requirements, limitations to the total amount of coal-fired (or any other type of) generation that can physically be installed within a certain timeframe, maximum allowable carbon emissions, or the imposition of a carbon tax.

The LRMCs of interconnected regions are likely to be interdependent because the optimal portfolio of generation can be located in different regions. Access to cheaper fuel and technology choices available to specific regions may imply the overall system cost is lower if excess generation capacity is built in one region and the surplus is exported to a neighbouring region.

Finally, although many of the parameters underlying the LRMC (including demand, fuel prices, and technology / capital costs) are inherently uncertain, the BRCI requires a single solution for the LRMC. Therefore, the analysis must seek to identify the best single estimate of each input to the LRMC, or at least to a single output from the calculation.

3.2.4. Options and approaches taken to the LRMC conceptual framework

As discussed in calculating the LRMC for the BRCI in previous years, there are several choices that must be made in developing the conceptual framework to be used in calculating the LRMC of an electricity system. These are discussed below.

Greenfield[29] vs. incremental

Consideration needs to be given to whether the modelling is done on the basis of supplying an increment of load beginning from the existing generation capacity base (i.e. incremental investment approach), or on a re-optimised, clean sheet basis ignoring the existing base of plant (a greenfield or re-optimised approach).

After consultation with stakeholders,[30] we considered that the greenfield approach is more in keeping with the intent of the clause in the Act that states that "*the estimate [of the cost of energy] must take into account the most efficient combination of generating plant to supply all of the NEM load of the State for relevant tariff year*". The greenfield approach provides the most scope for assessing the most cost-efficient means of meeting a given energy and demand requirement, as it allows optimisation of the cost of supplying the entire load. By contrast, an incremental approach would start with all existing plant, and the LRMC would have to be calculated based on the unamortized costs of these plants, and the least-cost means for serving any additional load resulting from load growth and/or plant retirement. It is also important to note that the greenfield approach provides a result for the LRMC which is consistent from year to year in the sense that the estimated LRMC is not affected by the over- and under-capacity resulting from lumpy, existing investments. It also produces a result for the LRMC that reflects the full mix of investments in different types of capacity that would be required to meet all aspects of the load curve (i.e. base load, mid-merit and peaking).

29 The term 'greenfield' was adopted in the CRA Addendum Report of May 2008. Previously, this approach had been referred to as 'stand-alone'.

30 This issue was discussed at the Stakeholder Workshop held in April 2007 as part of the process that developed the notified prices for 2007-08.

Isolated vs interconnected

Queensland is part of a larger, interconnected system, the diversity of which offers the potential to meet the energy and demand requirements of Queensland (and indeed each other region) at lower cost than would be the case if Queensland (and each other region) operated as a physically isolated system.[31] Therefore, the approach used addresses Queensland as part of the interconnected system that serves the NEM. This aspect of the approach was also used in calculating the LRMC portion of the BRCI for 2008-09.[32]

Single vs. multi-year – whether to allow for load growth and change in load factor

The LRMC of energy can be defined as the cost to meet an increment of load in a particular year or over a period of time. In a single year approach, the mix of plant chosen is that which would meet the load duration curve for the year being considered plus the requirement to provide another MWh of load in every hour of the year at lowest cost, based on the aggregate annualised capital and fixed and variable operating and maintenance costs, including fuel. However, generating plants are built to last for periods of up to 30 years or longer. As a result, the most cost-efficient mix of plant to service the load of a particular year may not be the most efficient when considered over a longer period of time. This can be especially problematic when the load in question has not been normalised to remove short-term variability which can arise from factors such as variations in the weather. Multi-year analyses attempt to capture the range and effect of such variables over the longer term in identifying the optimal mix of plant chosen.

In the case of the BRCI, the Regulation specifies that the LRMC is calculated to meet the demand profile (called the NEM load shape) formed over each half-hour electricity trading period of the State for the previous calendar year. As such, a single year is specified as the basis for identifying the optimal mix of generation plant, and changes in the LRMC from year to year will reflect, in part, differences in the load characteristics that pertained in the calendar year that preceded each of the tariff years in question.

---

31 Indeed, these efficiencies provided the original rationale for interconnection between the states and ultimately for the NEM.

32 The first calculation of LRMC in the BRCI process, for the 2007-08 tariff year, was different. In that initial analysis, the LRMC of meeting the Queensland load was developed in isolation from the NEM, using a screening curve. That approach was used at that time due to the limited time available for the analysis.

CRA has adopted an approach that seeks to incorporate at least some aspects of the multi-year approach by optimising the generation system with regard to how the single-year load would be expected to grow over the mid term. We have used the specified calendar year to serve as the base year load shape in Queensland for the optimisation and then grown that load using the 50% probability of exceedance, medium demand and energy growth projections from the NEMMCO *Statement of Opportunities* (SOO) published immediately prior to the tariff year to create a nine-year forecast load that serves as the base for the selection of an optimal generation system.[33]

This approach provides some consideration of the expected pattern of growth in the Queensland load in selecting the most efficient set of generation plant on which to base the LRMC for the subject tariff year, though it still rests on a historical year load as its base, which, as CRA has discussed previously, constitutes a source of possibly significant volatility in the BRCI.

The base year and load forecasts used for the other NEM jurisdictions are comprised similarly. The load duration shape is taken from specified CY data (CY 2008 for the 2009-10 tariff year calculation) and nine-year peak and energy forecasts for each of the NEM regions are taken from the corresponding SOO publications.

The schedule required for publication of the 2009-10 notified prices has made the use of a full calendar year of actual data impossible. The approach taken to estimating the CY 2008 load data and further discussion of how the forecast load is integrated with the load profile is presented in section 3.2.9 below.

Deterministic vs. probabilistic modelling

Many of the input costs (e.g. demand, fuel prices and technology costs) and operating conditions (e.g. plant availability) that determine the LRMC are inherently uncertain. Therefore, the LRMC can usefully be thought of as an expected value within a range that reflects uncertainties in these parameters. Probabilistic analysis using Monte Carlo modelling is able to capture the combined effects of many of the uncertainties and can produce a range of LRMC values from which an average or expected value can be chosen. This is particularly valuable when the analysis is seeking to identify the range of outcomes that could result from operational uncertainties.

---

33 The use of a nine-year forecast horizon was adopted in the final calculation of the LRMC for the 2009-08 tariff year reported in the Addendum Report. Previously, the timeframe extended to 2030. The forecast for the years past the end of the SOO forecast beginning each tariff year was taken from *Australian Energy National and State Projections to 2029-30*, ABARE Research Report 06, 26 December 2006. The use of the two sources required a calibration step so that the starting point of the ABARE forecast could be made to line up with the end of the SOO forecast period. Further analysis revealed that the LRMC that resulted when the timeframe was restricted to the SOO horizon differed very little from that which resulted from the longer timeframe that required the ABARE forecast. In addition, it was recognised that the ABARE forecast is only updated periodically, and between updates, the period on which the LRMC would be calculated would vary. Based on these two considerations, the decision was made to restrict the forecast period to that covered by the SOO.

By contrast, the BRCI is a ratio of how the costs of supplying electricity change between two years in which the load to be served and the costs of electricity plant and operation are known (or at least taken to be known), thereby allowing the optimum plant mix to be readily identified. This framework – including the formulation of the BRCI itself and its application as a factor that is used to adjust the level of the notified prices – is more suited to the use of a deterministic approach, using the best estimates of input values rather than probabilistic or scenario approaches for developing data or estimating results.

As a result, the LRMC calculations undertaken for the BRCI use deterministic, single-point estimates. Development of the single-point estimates used in the LRMC calculations for the 2009-10 tariff year horizon is discussed in section 3.2.12 below.

3.2.5. Options available and approaches taken in the LRMC modelling

There are different modelling approaches for estimating the LRMC, which range from the simple, to those that involve complex data and are computationally intensive. These methods can be grouped into three categories, as discussed below. Not surprisingly, decisions regarding the conceptual approach to be taken to the LRMC, as discussed above, will make some of the modelling approaches more or less applicable.

- ***Dominant technology*** – Methods that identify a dominant form of technology that set the LRMC of the system based on certain rules, or a simple screening curve. These methods are obviously simple but may not ensure the optimality of the investment decisions taking into account other issues that may influence investment/dispatch in a system.

- ***Explicit optimisation (single year, single region)*** – Methods that explicitly optimise the portfolio of generation investment to meet demand and calculate the LRMC as the shadow price of meeting an increment of demand over the longer term. The analysis for the 2004 IPART determination adopted this approach for NSW.[34] The linear programming model that was used optimised the investment and dispatch decisions to meet load represented as an annual load duration curve. The shadow price of meeting demand in the long term was explicitly quantified using three generic technologies: coal, closed cycle gas turbines (CCGT) and open cycle gas turbines (OCGT). However, this approach did not deal with the interconnection of NSW to the rest of the NEM, or the long-term evolution path of the system over multiple years. Instead, it was based on a snapshot year for a single region (NSW).

34 *The Long Run Marginal Cost of Generation in New South Wales*, Report to IPART, IES, February 2004.

- ***Explicit optimisation (multiple years, multiple regions***) – A multi-year, multi-region approach optimises investment across interconnected regions over a period of years to calculate the optimal portfolio, taking into account the initial portfolio of optimal generation assets and how it will evolve over the years to the long-term equilibrium to elicit the LRMC. This is obviously the most comprehensive of the three methods, but its use is also very data intensive and demanding. Such an approach was used to estimate the LRMC of energy for NSW[35] in the 2007 IPART determination.

We have used an explicit optimisation approach that incorporates multiple years and multiple regions. This approach recognises that:

- The set of plants that would be selected to meet the energy and demand requirements of a given year may not be the most cost-effective mean for meeting energy and demand requirements over a somewhat longer period, particularly as generation plant represents long-lived assets. Such consideration is of increased concern in application to the BRCI because the energy and demand requirements used for the initial year are not weather normalised.

- Queensland is part of a larger, interconnected system, the diversity of which offers the potential to meet the energy and demand requirements of Queensland (and indeed each other region) at lower cost than would be the case if Queensland (and each other region) operated as a physically isolated system.

3.2.6. The CRA model used to derive the LRMC

We have used CRA's proprietary model CEMOS to derive the required LRMC. CEMOS comprises three modules for undertaking long-term (PEPPY), short-term (STEMM) and strategic bidding (CONE) analyses of the electricity market. The present analysis has deployed the long-term module of CEMOS only since all existing plant have been removed from the NEM for the purposes of the analysis.[36]

The long-term module of CEMOS models the bidding and dispatch of individual power stations to match expected electricity demand profiles and levels over multiple years, taking into account the regional structure of the NEM and other important characteristics of the market:

35 *Energy Costs,* Report to IPART, Frontier Economics, April 2007.

36 Appendix D has a detailed account of the functionalities of the PEPPY module. The long-term cost estimation part of the present analysis does not employ short-term dispatch or strategic generator bidding analysis. However, such short-term and strategic bidding analyses in combination with the long-term PEPPY module has been used to derive near term forecast of half-hourly market prices as discussed later in this report.

- CEMOS uses a five region (Queensland, New South Wales, Victoria, South Australia and Tasmania) representation of the NEM that reflects inter-regional network limitations (constraints). Each of these regions is modelled as a "node" (i.e. a single location in the market) – demand and generation are modelled relative to that node. The nodes are connected by interconnectors, where limits are placed on the level of transfer between the nodes.[37] CEMOS does not optimise transmission expansion and uses transmission expansion options that are identified as part of the Annual National Transmission Study (ANTS). In other words, the interconnector limits in the future may typically be higher by the amount identified in the ANTS as cost-effective (with a benefit cost ratio higher than 1). This modelling representation is reflective of the actual dispatch and pricing process performed by the market clearing engine in the NEM; and

- The long-term module of CEMOS evaluates dispatch and pricing outcomes using an annual load duration curve of 40 time periods per year or "blocks" of demand. Each demand block has an associated number of hours in the year when that level of demand occurs. These load blocks are developed from the half-hourly load data used in the short-term modelling, i.e. the STEMM model.

CEMOS dispatches generators to meet the demand in each of the 40 blocks of demand in each year. The dispatch optimisation process also yields the regional spot prices for each of the load conditions modelled.

CEMOS incorporates a range of capabilities, and has two features that are particularly important for modelling actual and long-term market outcomes:

- CEMOS' long-term capacity expansion module optimises decisions on timing, location and technology of new generation capacity as and when required in order to meet growing demand; and

- In doing so, CEMOS explicitly recognises the role of fixed costs (i.e. capital and fixed operation and maintenance costs) and variable costs (i.e. fuel and non-fuel variable operation and maintenance costs) across multiple regions that are connected by the inter-regional transmission lines.

37 The Snowy region was abolished from 1 July 2008. We have therefore not modelled Snowy as a separate region, and have allocated the generators previously positioned in the Snowy region to Victoria and NSW.

CEMOS incorporates both a price "trigger" (a point at which future investment would become viable) and a reliability "trigger" (a point at which policy makers would intervene if there were too many electricity outages), so that capacity would be built even if spot prices were not high enough to justify a commercial investment. There is usually a time lag between when supply shortages arise and when capacity can be commissioned so that electricity investment has to be commissioned well before price rises or shortages occur. CEMOS therefore minimises the overall cost of the electricity system by performing an inter-temporal optimisation for capacity (sometimes referred to as perfect foresight), looking ahead over the entire planning period, while solving the operational dispatch problem for each year simultaneously.

Some of the decisions such as expansion of generation capacity and dispatch are decision variables in the CEMOS model whereas others such as transmission capacity, fuel price, carbon price, cost of capital, demand growth are exogenous parameters that drive such decisions. PEPPY provides a framework to develop insights about the implications of the longer term market drivers including future entry, longer term effects of market power, effects of longer term gas supply constraints, etc. The key features include:

- Detailed consideration of fuel contracts, load growth and its temporal/spatial distribution, new CCGT costs, and vesting contracts;
- Replicating, where possible, the market clearing process of the system;
- Load duration curves using NEM load data, forecast of peak and energy based on the NEMMCO Statement of Opportunities and ABARE (if desired);
- Transmission; and
- Ancillary Services.

Appendix D contains further background on the CEMOS model and its application, and provides references to reports that are available in the public domain containing additional details.

3.2.7. Summary of submissions to the Interim Consultation Notice relating to the LRMC

Comments in the submissions to the Interim Consultation Notice (ICN) related to the LRMC addressed the following general topic areas:

- The use of the total Queensland load rather than that load less the load of customers directly connected to the transmission system as the NEM load for the purpose of calculating the LRMC – This was mentioned in a number of the submissions including those from AGL, APG, Origin and TRU. As noted in section 2.6, the Terms of Reference for this study stated that the expectation of the Authority is that the framework adopted in the 2008-09 BRCI determination would also be used in the 2009-10 calculation. As a result, we have again used the whole NEM load in calculating the NEM load. We expect that this issue will be raised for discussion at the Workshop to be held in late August.

- The use of 15-year trended data rather than current year data as inputs to the calculation of the LRMC – This was also commented on by a number of the stakeholders that put forward submissions. Again, the use of trended data was decided upon in the 2008-09 final decision and as such was specified in the Terms of Reference as the expected approach to be used in the 2009-10 analysis. In its submission AGL mentioned that it would again be commissioning ACIL Tasman to collect recent data on various key inputs to the LRMC calculation. To the extent that these can be integrated into the trend analysis framework and the study timeframe this data is expected to make a valuable contribution. It is also expected that the trended approach will be discussed at the Workshop.

- The need to take account of the impact of the new national Renewable Energy Target (RET) and the emissions trading scheme on the LRMC – Virtually all of the submissions from electricity industry organisations stated that the impact of the new RET and the cap and trade emissions trading scheme that has been announced by the Commonwealth government should be taken into account in the calculation of the LRMC. We agree with this view and have included these policies in the LRMC calculation.

- The additional risk that the shortened timeframe imposes on the calculation of the BRCI in general and the LRMC in particular – The shortened timeframe for development of the 2009-10 BRCI and notified prices was commented on in virtually every submission. With regard to the LRMC, commentators noted that the shortened timeframe will require that almost half of the load data that is specified for use in the Regulation as a primary input to the calculation of the LRMC will need to be forecast rather than being drawn from actual data. While we have used all due care in undertaking the forecast, it must be recognised that it is very likely that the actual load data that will be available by the end f CY 2008 will differ from the combination of actual and forecast data used in this First Report. This interjects a source of uncertainty and risk in the calculation of the LRMC that should not be ignored.

In addition to these major points, specifics were raised in a number of the submissions with regard to specific inputs that were used in the 2008-09 calculation and suggestions made for the how the data inputs could be improved.

3.2.8. Effect on the LRMC calculation of the requirement to complete the BRCI process by 1 December 2008

The Regulation (Electricity Regulation 2006) requires that the LRMC be calculated to meet the demand profile (called the NEM load shape) formed over each half-hour electricity trading period of the State for the previous calendar year. Therefore, the LRMC for the 2009-10 BRCI should be calculated with reference to the actual loads experienced in CY 2008.

However, the requirement to complete the 2008-09 BRCI process by 1 December 2008 means that the full year of load data required by the Regulation will not be available for the calculation.

For this First Report, actual load data for the period 1 January to 15 July 2008 was available. A modest amount (approximately 2 months) of additional actual data will be available for the Second Report. The load in the remaining half-hour periods of the year must be forecast. These half-hour forecasts have been generated using the Load Duration Curve (LDC) module in the CEMOS model.

The LDC module requires the following inputs for each jurisdiction:

- A year's worth of half hour load data, expressed in two ways:
    1. As a load shape, i.e. load ordered peak (largest) to smallest and expressed as a percentage of the peak demand); and
    2. In chronological order.
- A projection of peak demand in each year we are forecasting the LDC; and
- A projection of total annual energy in each year we are forecasting the LDC.

The peak demand and energy projections are sourced from NEMMCO's "2008 Energy and Maximum Demand Projections" report which was released in July 2008. This report is released by NEMMCO prior to the release of the annual Statement of Opportunities (SOO) but contains peak and energy projections as they will appear in the upcoming SOO. NEMMCO's peak and energy forecasts are made on a financial year basis.

The output from the LDC model is a set of half hour load forecasts for each jurisdiction, grouped into financial years (in line with NEMMCO's peak and energy projections being for financial years). The forecasts for 16 July 2008 to 31 December 2008 will be used along with the historical load data for 1 January 2008 to 15 July 2008 to form a complete set of half-hour loads for the 2008 calendar year, as required for the 2009-10 tariff year LRMC calculation.

3.2.9. Forecasting the remainder of the calendar year 2008 load

This section considers various issues associated with forecasting the load to pertain in the remainder of the 2008 calendar year, and how we have attempted to resolve those issues. It also shows the results our forecasts in various graphs.

Choice of historical year to use for the load in each jurisdiction

A year's worth of historical half hour load data is required for each jurisdiction to forecast the remaining half hour periods of 2008. We used the 2007-08 financial year as the historical year for all jurisdictions. This means that the most recent year's worth of data is used to forecast the load for the remainder of 2008. Using this data also allowed us to include the data available for 2008 as part of the forecasts.

It was not ideal to simply use 16 July 2007 to 31 December 2007 load data as a proxy for this period in 2008 as there is likely to have been some growth in both peak and energy between the second half of 2007 and the second half of 2008. Such growth would not be captured by simply marrying the available 2008 load data with 2007 data for the missing 2008 dates. Using the LDC function in CEMOS allowed us to take into account the latest year's load shape for each jurisdiction and grow these according to NEMMCO's published peak and energy projections.[38]

Other statistical methods for approximating load for the second half of 2008 were considered but many of these methods are capable of creating LDCs only, and not chronological half hour load projections, as required in this instance in order to complete the 2008 calendar year's worth of half hour loads.[39]

Choice of economic growth and temperature scenarios to assume for peak and energy projections

In the NEMMCO report, peak projections are provided for combinations of three economic growth scenarios (low, medium, high) and three temperature scenarios (10POE, 50POE, 90POE), for a total of nine scenarios. Energy projections are provided on an annual basis for three economic growth scenarios (low, medium, high).

38 This approach has the virtue of capturing the influence of the most current appliance saturation on load. On the other hand, it assumes that other drivers of demand – notably weather – will be similar in the second half of 2008 as they were in the second half of 2007. This is less obviously the case, and we have simulated another LDC based on an averaging of the loads (as a percentage of a reference load) in the second half of recent years in each jurisdiction – see Appendix C.

39 See Appendix C for further discussion of the limitations of various statistical techniques for creating part year LDCs.

On average, a SOO “medium 50POE” scenario should eventuate, so we are using this combination of economic growth and temperature scenarios for the load forecasts. The LDC module in CEMOS is used to calculate half hour load forecasts for the remainder of 2008. This module uses a least-squares method of fitting NEMMCO’s peak and energy projections to the given load shape and producing a corresponding set of chronological loads. The load forecasts for the remainder of 2008 are then used along with the actual load data for the first part of 2008 to represent the 2008 calendar year load shape in the calculation of LRMC.

As a test of how well the forecasts follow on from the actual 2008 load data, the resulting complete calendar year worth of loads are plotted chronologically to see if the load profile is reasonable. We would expect the profile to appear continuous as we move from actual load to forecast load i.e. no step change.

The forecasts showed relatively smooth continuation from the actual load in all jurisdictions but Queensland. Although NEMMCO’s recent forecasts of peak demand in Queensland have exceeded the observed peak, their forecasts of peak remain high in the 2008 report. For example, in the SOO 2007, the forecast for medium 50POE peak in 2007/08 was 9,461 MW but the actual peak over this period turned out to be 8,086 MW (this is low compared to even the most conservative 2007/08 peak forecast of 8,899 MW which corresponds to the low 90POE scenario). Despite this overestimation in last year’s report, the 2008 report (which was released this July after the 2007-08 actual peak and energy outcomes were known) contains similarly high estimates of peak. When we observed the graph of Queensland’s load for the first part of 2008 and the medium 50POE forecasts for the second part of the year, the peaks appeared far too high. For this reason, we have proceeded using the medium 90POE forecasts for Queensland. We note that the peak and energy forecasts for all other jurisdictions in NEMMCO’s 2008 report are a reasonable continuation of trends seen in recent historical data; Queensland is the only jurisdiction for which the peak forecasts do not appear to match the historical trends.

Figure 3 to Figure 7 below show the resultant 2008 calendar year loads. These are used as the load shapes in the 2009-10 tariff year LRMC calculation. The plots look continuous as we move from actual data to forecasts. This supports the choice of economic growth and temperature scenario for each jurisdiction.

Figure 3: 2008 calendar year load for Queensland

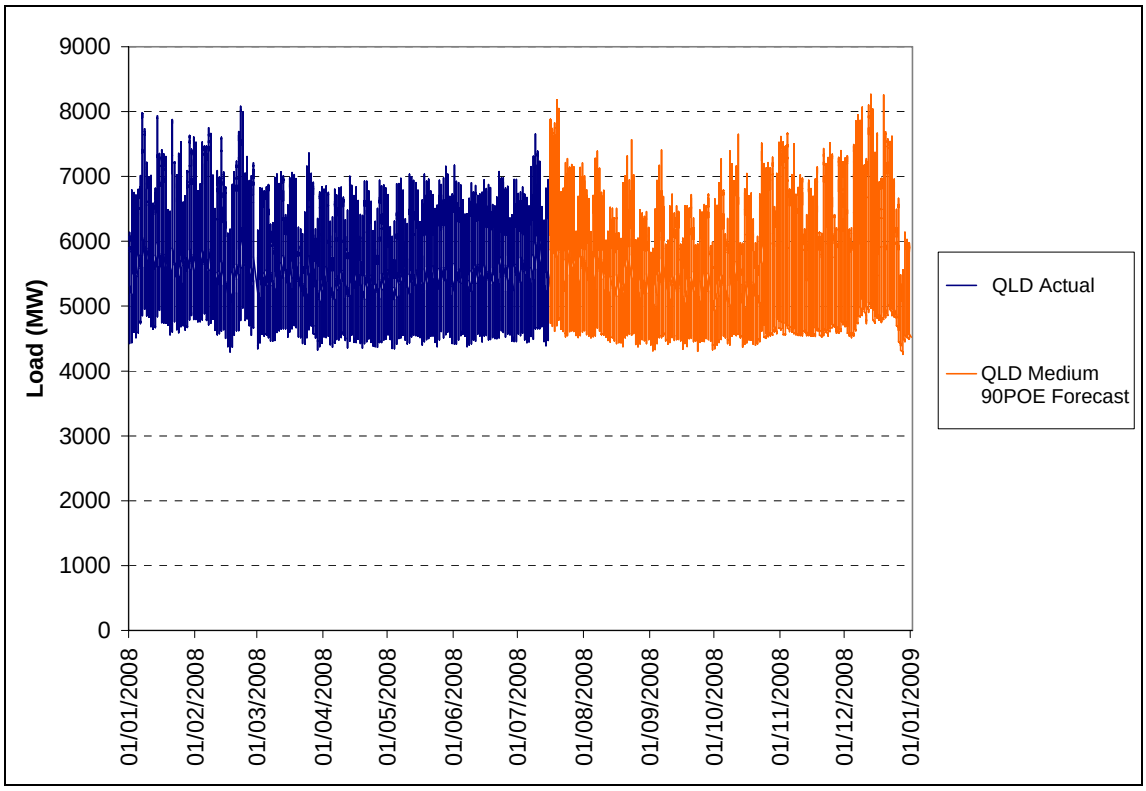


Figure 4: 2008 calendar year load for New South Wales

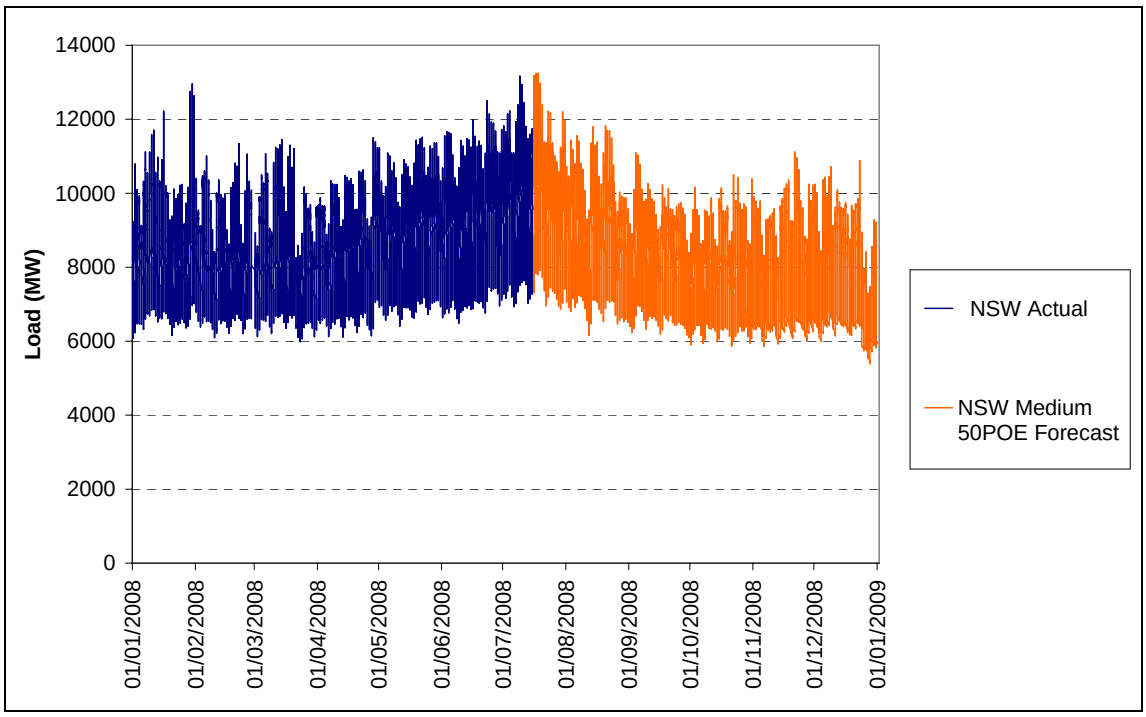


Figure 5: 2008 calendar year load for South Australia

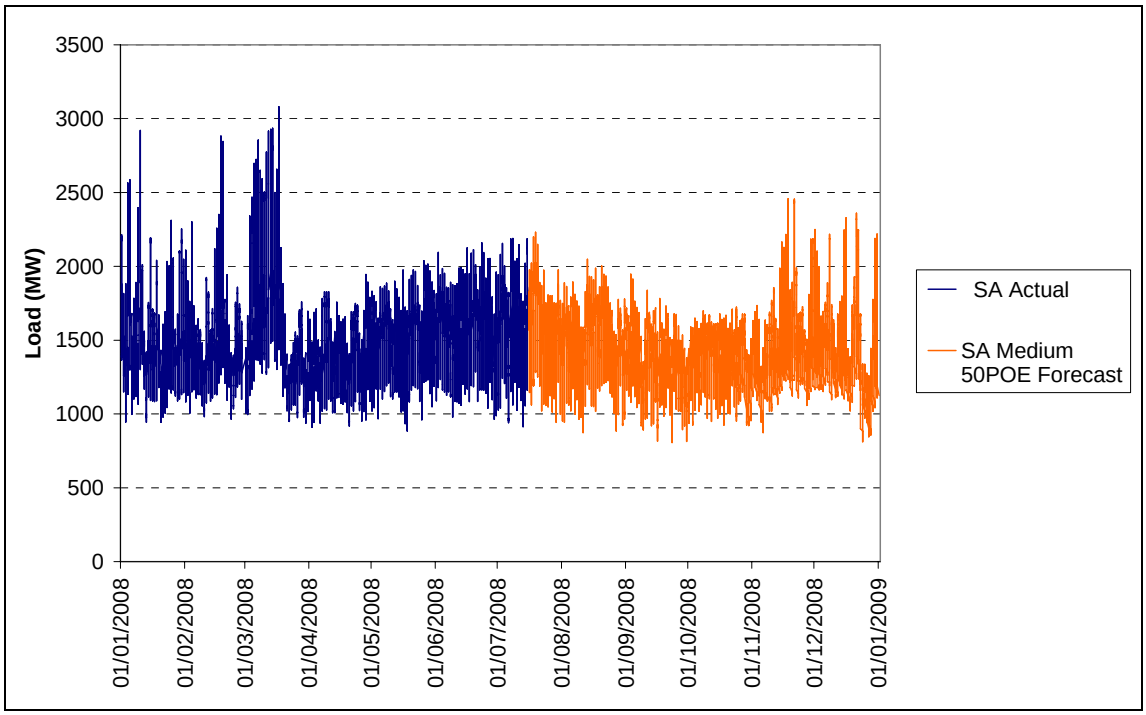


Figure 6: 2008 calendar year load for Victoria

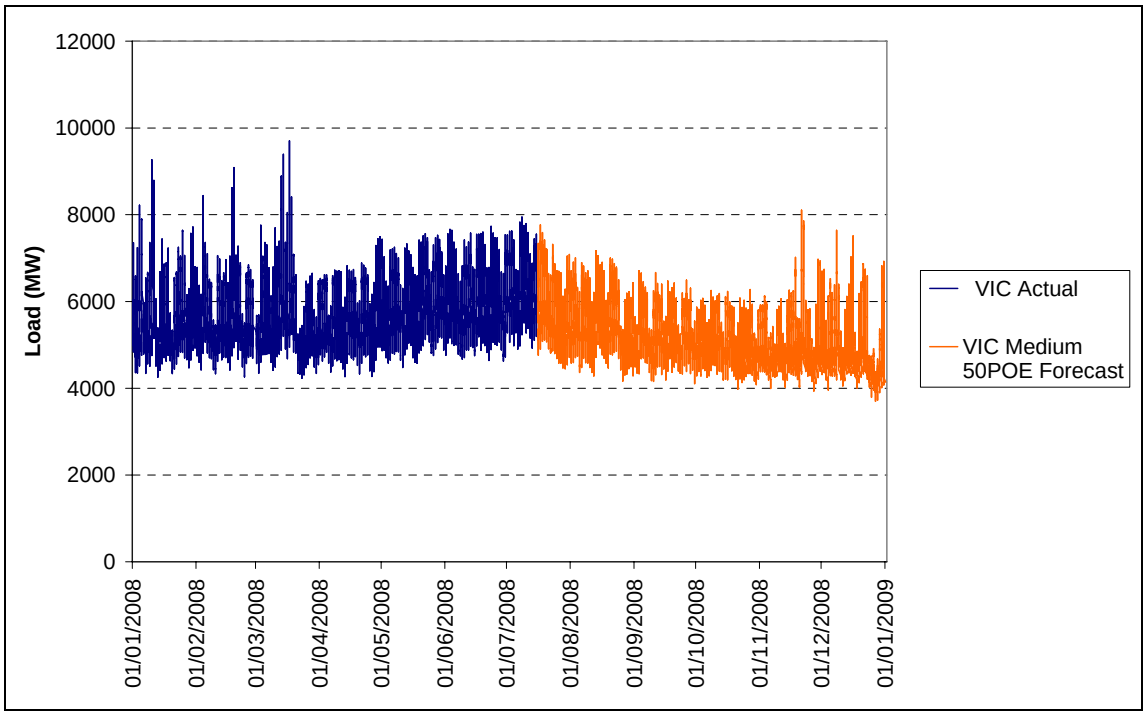
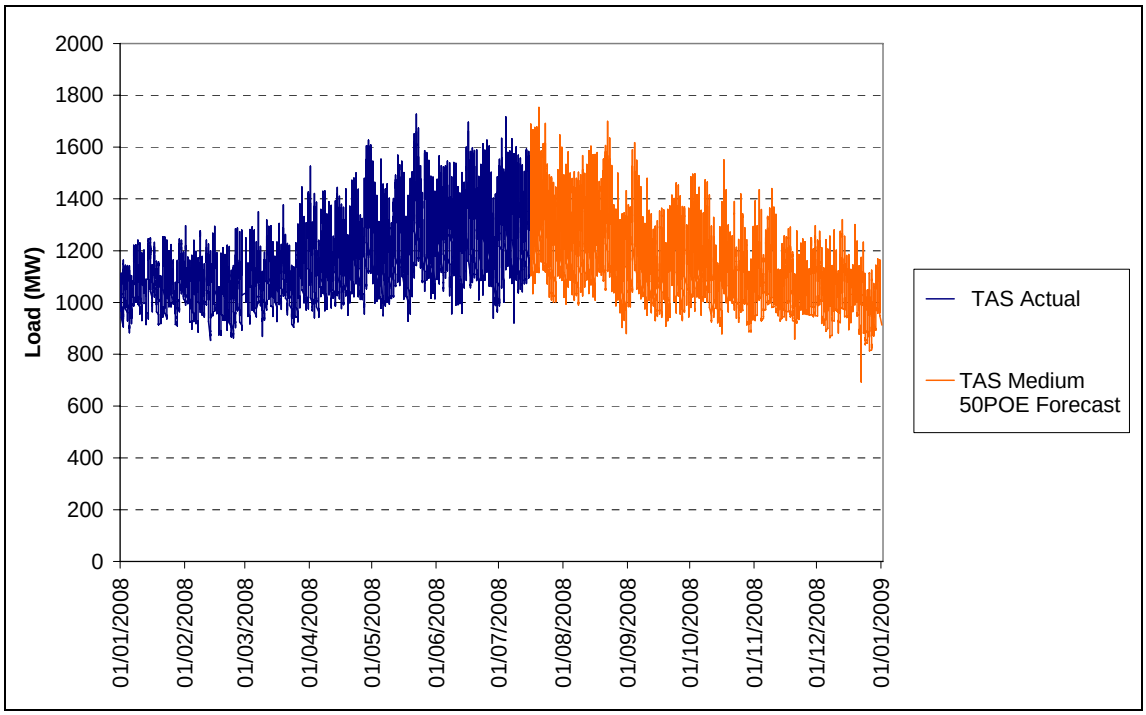


Figure 7: 2008 calendar year load for Tasmania



Another test of how well the forecasts complete the 2008 calendar year is to plot the resulting LDC for each jurisdiction. By first comparing the LDC for the first half of 2008 to the LDC for the first half of 2007, we can observe how the load shapes for the two half-years compare. It is not unreasonable to expect that the relativity observed between the two half years will be approximately maintained when we compare the complete 2007 LDC to the complete 2008 LDC.[40] This is because if, for example, the first half of 2008 is less peaky (flatter) than the first half of 2007, then the load shape for the whole year (which includes the less peaky first half of the year) is also likely to be less peaky than the load shape for the whole 2007. A comparison of half- and full-year LDCs for Queensland is shown below in Figure 8 and Figure 9 below.

40 There is, however, no absolute necessity that this relativity be maintained either. As described above, all other things being equal, a peaky first half of the year will make the full year peakier than a less peaky first half year. However, as peaks are often driven by weather conditions, and a very mild winter can follow a very hot summer, for example, there is now guarantee that the second half of the year will be peaky just because the first half was. Having said this, the method used has been shown to produce internally consistent and defensible forecast loadshapes.

Figure 8: Half-year LDC for Queensland – comparison of the first half of 2007 and 2008

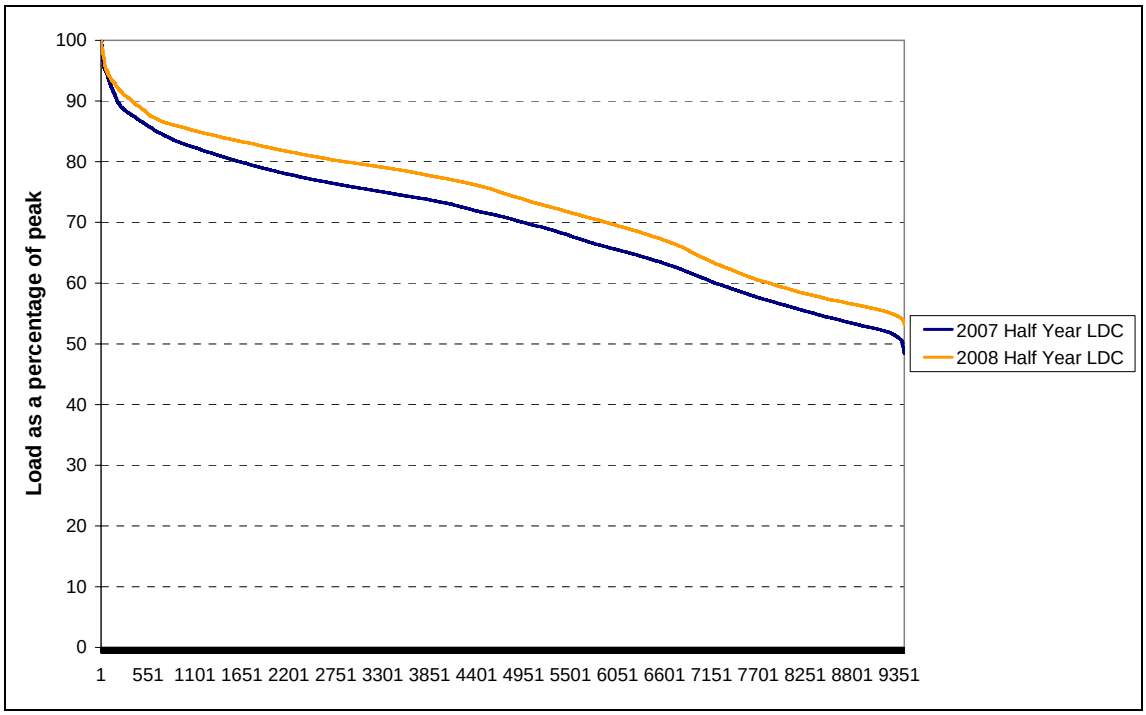
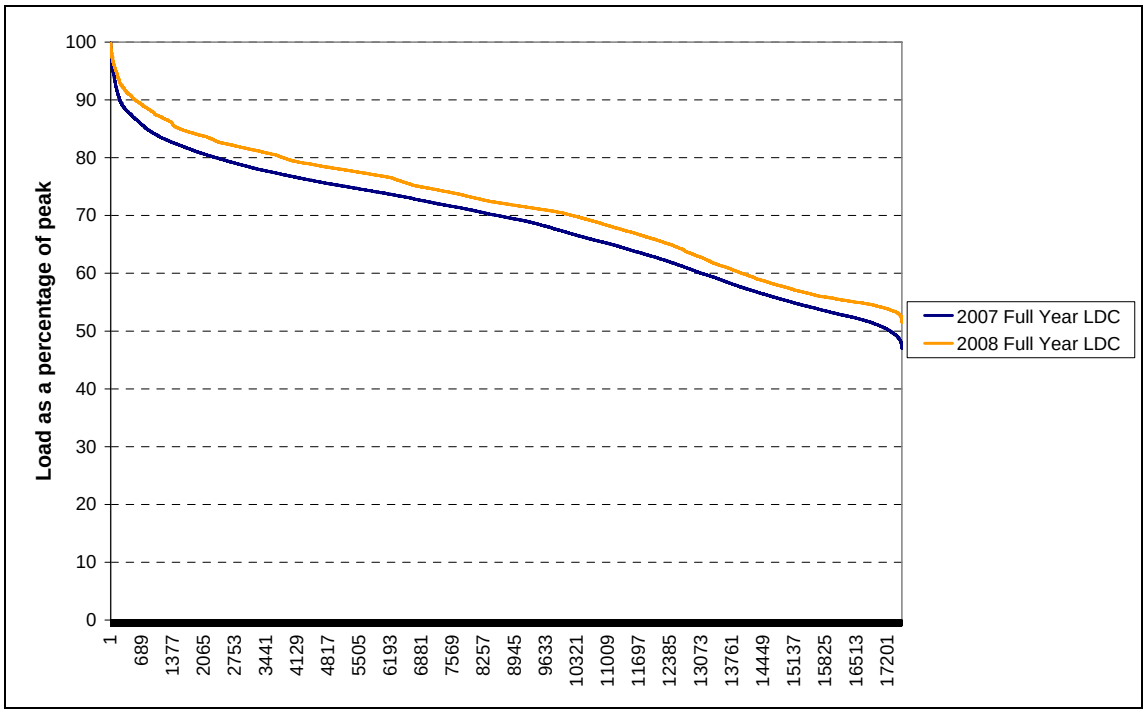


Figure 9: Full-year LDC for Queensland – comparison of 2007 and 2008



3.2.10. Likely introduction of an emissions trading scheme (ETS)

The Federal Government has expressed a commitment to introduce a cap and trade scheme for carbon emissions commencing in 2010. The scheme will issue a limited number of permits for the right to emit carbon. Each permit will authorise one tonne of carbon emissions. The number of permits to be issued each year will be determined in light of the level of carbon reductions that the government wants to achieve. The permits will be auctioned off (though some may be allocated to existing fossil-fuelled electricity generators and trade exposed industries). The number of permits in combination with the capital cost of different types of electricity generation plant and their relative carbon emission intensity will determine the price of the permits.

Several studies have been conducted regarding the likely cost of permits under various scenarios. We have used a study submitted to the Garnaut Climate Change Review[41] by the ESAA[42] as the source of the permit prices used in this study.

The ESAA study assessed permit prices under two scenarios, in which reductions in carbon emissions of 10% and 20% below the business as usual (BAU) level are set as targets. The permit prices for each of these scenarios over the nine years of the modelling horizon are shown in Table 4 and then plotted in Figure 10 below.

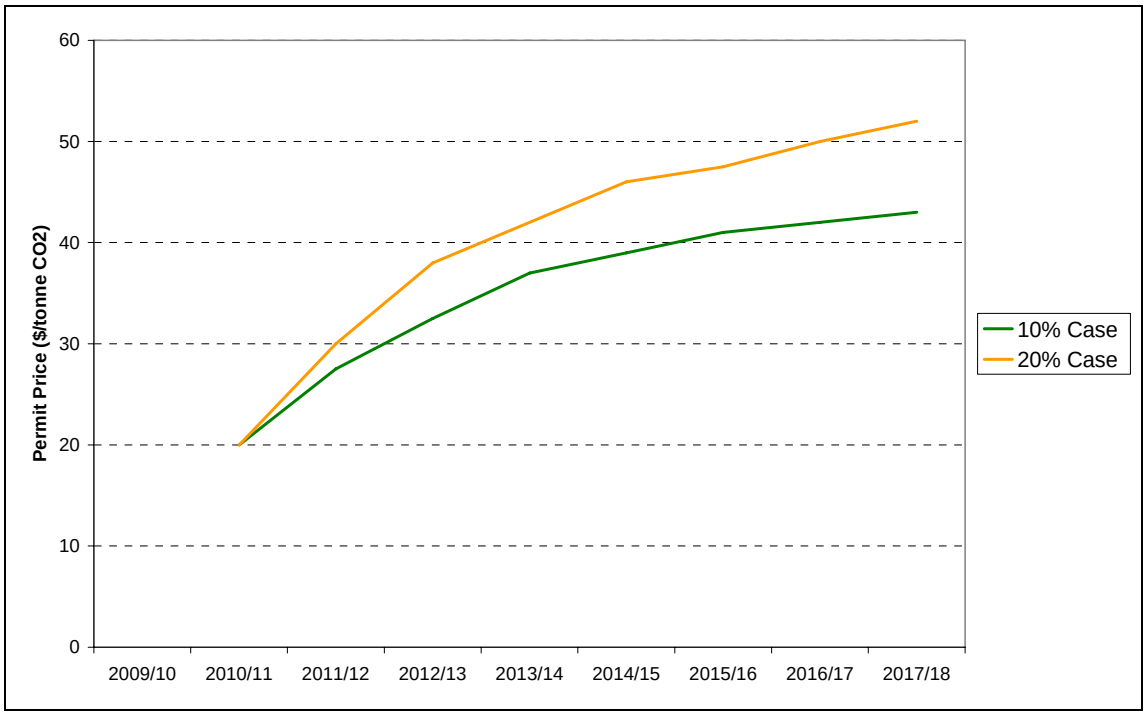
Table 4: Permit prices used in the LRMC modelling

Year	10% Case permit price ($/tonne CO2)	20% Case permit price ($/tonne CO2)
2009/10	-	-
2010/11	20.00	20.00
2011/12	27.50	30.00
2012/13	32.50	38.00
2013/14	37.00	42.00
2014/15	39.00	46.00
2015/16	41.00	47.50
2016/17	42.00	50.00
2017/18	43.00	52.00

41 See www.garnautreview.org.au.

42 *The impact of an ETS on the energy supply industry*, prepared by ACIL Tasman for ESAA, July 2008.

Figure 10: Permit prices used in the LRMC modelling



These prices have then been used as additions to the variable costs of fossil-fuelled plants by reference to the fuel type and heat rate (thermal efficiency) of each different type of fossil fuel plant configuration. This approach is a bit synthetic in that it takes the price as a fixed input schedule to the analysis, whereas in the actual operation of the scheme, the price will be an output of market activity taking into account the number of permits available and the cost of electricity generation technologies with lower (or zero) emissions.

The fact that the BRCI LRMC calculation is undertaken from a greenfield perspective results in very different outcomes than do any of the major studies that have investigated the carbon prices that are likely to eventuate from the ETS. Virtually all of these studies have used an incremental analysis, which is appropriate because this perspective allows elucidation of the impact of the scheme on existing carbon emitting generators, and the likely carbon prices that will exist in Australia under different scenarios and carbon reduction targets.

As a result, the analysis undertaken in this study cannot be viewed as an estimate of the carbon prices that will result in the future. Indeed, we have taken an estimate of the carbon prices that are likely to eventuate as an input into this study, rather than their being an output of it. In this study, the carbon price is used to provide a view of how a possible set of relativities between the capital and variable costs – including carbon – of different generation plant types would affect the calculation of LRMC on a greenfield basis.

3.2.11. Renewable Energy Targets

The Federal Government has announced that the Australia-wide Mandatory Renewable Emissions Target (MRET) is to be revised, and more details are available since the last calculation of the BRCI. The scheme currently requires that renewable energy sources account for 9,500 GWh by 2010 and remain at that level until 2020. The scheme is to be revised to ramp up to 45,000 GWh from renewable energy sources by 2020.

From the perspective of calculating the LRMC, this requires that an additional constraint be placed on the plant mix to be selected in the greenfield generation system expansion/optimisation analysis that is at the heart of the LRMC.

The COAG working group on climate change and water released a consultation earlier in 2008 which invited submissions on possible approaches to setting annual targets by 31 July 2008. A response paper covering the submissions has not yet been released so no firm detail has been provided on how the renewable energy share will be required to ramp up toward the 2020 target. In the absence of a specified ramp rate, we have adopted an annual ramping of the MRET based on the proportion of total Australia-wide sent-out generation that is traceable to NEM jurisdictions. The 2008 ESAA "Electricity Gas Australia" report details the sent-out generation in each Australian jurisdiction. We calculated the NEM total sent-out generation as a percentage of the total Australia-wide sent-out generation. Results are shown in Table 5 below.

Table 5: Calculating NEM sent-out generation as a % of total Australian sent-out generation

	Sent-out generation (GWh year ending 30 June 2007)	NEM jurisdiction (Y/N)
NSW & ACT	65,549	Yes
VIC	49,293	Yes
QLD	55,578	Yes
SA	11,814	Yes
WA	15,341	No
TAS	9,252	Yes
NT	1,405	No
Snowy	2,940	Yes
Total all jurisdictions	**211,171**	**-**
Total NEM	**194,426**	**-**
NEM % of total	**92.07%**	**-**

The required renewables levels of 9,500 GWh in 2010 and 45,000 GWh in 2020 were scaled by the ratio shown in Table 5 above. From there we calculated a constant growth rate to be applied to the NEM target each year from 2011 to 2020 inclusive in order to meet the 2020 target. The annual growth rate is 16.83%. Table 6 below shows the resulting annual targets for the course of the LRMC run. These are only an estimate of what each year's renewable energy target may be; the Federal Government has not yet published the method that will be used to set the actual annual targets.

Table 6: Annual Renewable Energy Targets

Year	Renewable Energy Target (GWh/year)
2009/10	8,747
2010/11	9,480
2011/12	11,069
2012/13	12,923
2013/14	15,089
2014/15	17,618
2015/16	20,570
2016/17	24,018
2017/18	28,042

3.2.12. LRMC modelling input assumptions

Key inputs are:

- Generation plant capital costs;
- Fuel costs – coal;
- Fuel costs – gas;
- Fixed O&M and escalation rate;
- Variable O&M;
- Thermal efficiencies and auxiliaries;
- Plant availability;
- WACC; and
- Project life.

Each of these is discussed in the following sections.

Generation plant capital costs

Capital costs for supercritical black coal, brown coal, CCGT and OCGT generation plant have been taken from the ACIL 2007 report, Tables 77, 78 and 81. ACIL lists a capital cost estimate in nominal dollars for the years 2007-08 to 2025-26. The capital costs listed for 2009-10 are used for the LRMC calculation and are shown in Table 7 below.[43]

We were unable to source any publicly available data on the capital costs of wind, hydro, geothermal or biomass generators that has achieved widespread acceptance in Australian generation expansion studies. For this reason, we used the average of the US Annual Energy Outlook (AEO) 2007 and AEO 2008 values (these were first converted into AU$2009-10 costs and then averaged). The AEO data for wind and hydro generation matched fairly well with several estimates of these costs in Australia, but the geothermal and biomass figures varied considerably. In addition, we recognise that the site environment and technologies themselves may differ in Australia as compared to the U.S., and therefore invite submissions on capital costs that may better represent the cost of installing these technologies in Australia, and would particularly welcome such information on geothermal and biomass plant.

43 Note that the ACIL 2007 report assumes that the capital cost of these types of plant will escalate at 80% of CPI.

Table 7: Capital costs used in the 2009-10 tariff year LRMC calculation

	Capital Cost (2009-10$/kW)	Annualised Capital Cost ($/MW/year)	Source[44]
Supercritical Black Coal	1,769	175,250	ACIL 2007, Table 78
Brown Coal	1,977	195,856	ACIL 2007, Table 79
CCGT	1,092	108,181	ACIL 2007, Table 77
OCGT	749	74,201	ACIL 2007, Table 81
Wind	2,353	233,092	AEO 2007
Hydro	2,705	268,022	CRC CCSD
Geothermal	2,146	212,635	Average of AEO 2007 and AEO 2008
Biomass	3,336	330,536	Average of AEO 2007 and AEO 2008

Fuel costs – coal

The ACIL 2007 report provides coal costs for 2007-08 to 2025-26 in 2007-08 dollars. For this LRMC calculation, we need coal costs for 2009-10 to 2017-18 in 2009-10 dollars. The ACIL 2007 estimates for each jurisdiction over these years were translated into 2009-10 dollars using an annual CPI of 2.5%. Table 8 below shows the resulting coal costs over the LRMC modelling horizon for each NEM jurisdiction.

44 Data sources:

Fuel resource, new entry and generation costs in the NEM, Report 2 – Data and documentation, Report prepared for NEMMCO, ACIL Tasman, June 2007.

Assumptions to the Annual Energy Outlook, US Energy Information Administration, April 2007 and April 2008.

Options for Electricity Generation in Australia, Cooperative Research Centre for Coal in Sustainable Development (CRC CCSD), Technology Assessment Report, P. Graham et al, 31 January 2005.

Table 8: Coal fuel costs used in the 2009-10 tariff year LRMC calculation

	Queensland (2009-10$/GJ)	New South Wales (2009-10$/GJ)	Victoria (2009-10$/GJ)
2009-10	0.9876	1.1137	0.5673
2010-11	0.9876	1.1067	0.5673
2011-12	0.9841	1.1067	0.5673
2012-13	0.9806	1.1067	0.5673
2013-14	0.9771	1.1032	0.5673
2014-15	0.9771	1.0962	0.5673
2015-16	0.9771	1.0962	0.5673
2016-17	0.9701	1.0962	0.5568
2017-18	0.9666	1.0927	0.5568

Fuel costs – gas

Gas delivered to CCGT plant

We adopted the same method for calculating gas costs as was used for the 2008-09 LRMC calculation. Costs for gas delivered to CCGT plant were developed by a "trended cost" method using ABARE information on the spot price of gas in Victoria over the years 2002-03 through 2006-07 inclusive,[45] as shown in Table 9 below.

Table 9: Victoria gas spot prices (real 2006-07 $/GJ)[46]

	2002-03	2003-04	2004-05	2005-06	2006-07
Gas spot prices	$3.20	$3.22	$3.17	$3.25	$3.36
Year on year % change	-	0.63%	-1.55%	2.52%	3.38%

Source: ABARE

45 *Energy in Australia 2008*, ABARE, February 2008.

46 Calculated as financial year averages of daily spot prices in the Victorian gas market.

As in the 2008-09 tariff year LRMC calculation, a transportation cost of $0.50/GJ was added in real dollars to the price in each year, and then a linear trend line was determined for this price path and extended to 2009-10. Nominal prices were then derived for the 2009-10 tariff year by applying the long-run annual inflation factor of 2.5%. Lastly, the nominal Victoria prices were used to derive 2009-10 prices in the other NEM states by reference to the relativities between the average prices of gas in Victoria and the various other states as shown in the ACIL 2007 report. Table 10 below shows CCGT fuel costs over the LRMC modelling horizon for each NEM jurisdiction.

Table 10: CCGT fuel costs used in the 2009-10 tariff year LRMC calculation

	Queensland (2009-10$/GJ)	New South Wales (2009-10$/GJ)	Victoria (2009-10$/GJ)	South Australia (2009-10$/GJ)	Tasmania (2009-10$/GJ)
2009-10	3.8934	4.2376	4.2160	4.6793	4.3757
2010-11	3.9283	4.2755	4.2537	4.7211	4.4148
2011-12	3.9631	4.3134	4.2914	4.7630	4.4539
2012-13	3.9979	4.3512	4.3291	4.8048	4.4930
2013-14	4.0327	4.3891	4.3668	4.8466	4.5321
2014-15	4.0675	4.4270	4.4045	4.8885	4.5712
2015-16	4.1023	4.4649	4.4422	4.9303	4.6104
2016-17	4.1371	4.5028	4.4799	4.9721	4.6495
2017-18	4.1719	4.5407	4.5176	5.0140	4.6886

Gas delivered to OCGT plant

The trended cost of gas delivered to OCGT plant in each state was estimated by applying the 125% factor cited in the ACIL 2007 report to the delivered price of gas to CCGT plant determined for each state for the 2009-10 tariff year. Table 11 below shows OCGT fuel costs over the LRMC modelling horizon for each NEM jurisdiction.

Table 11: OCGT fuel costs used in the 2009-10 tariff year LRMC calculation

	Queensland (2009-10$/GJ)	New South Wales (2009-10$/GJ)	Victoria (2009-10$/GJ)	South Australia (2009-10$/GJ)	Tasmania (2009-10$/GJ)
2009-10	4.8668	5.2970	5.2700	5.8491	5.4696
2010-11	4.9103	5.3443	5.3171	5.9014	5.5185
2011-12	4.9538	5.3917	5.3643	5.9537	5.5674
2012-13	4.9973	5.4391	5.4114	6.0060	5.6163
2013-14	5.0408	5.4864	5.4585	6.0583	5.6652
2014-15	5.0844	5.5338	5.5056	6.1106	5.7141
2015-16	5.1279	5.5811	5.5527	6.1629	5.7630
2016-17	5.1714	5.6285	5.5998	6.2152	5.8119
2017-18	5.2149	5.6758	5.6469	6.2675	5.8608

Fuel costs for biomass generation

The fuel cost is taken from the CCSD Technology Assessment Report 72, published 2008. This report outlined that biomass fuel cost would be, on average, $1.50/GJ. This estimate was in 2005 dollars, so CPI has been applied for the cost to be $1.576/GJ in 2009-10 dollars.

Fuel costs for other types of renewable generation

Wind, hydro and geothermal generators do not incur fuel costs.

Fixed and variable generation operation and maintenance costs

The two main categories of generation operating costs (other than fuel costs) are Fixed Operating and Maintenance (FOM) and Variable Operating and Maintenance (VOM). For black coal, brown coal, CCGT and OCGT, both sets of costs are from the ACIL 2007 report and have been converted to 2009-10 dollars by applying the stated escalation rate of 100% of CPI of 2.5% per annum. Note that ACIL provides the same estimate of FOM and VOM in their 2007 and 2008 reports.

For hydro and wind generators, FOM and VOM are taken from the CRC report for *Coal in Sustainable Development (CCSD) – Technology Assessment Report 44*, Jan 2005. These costs have been translated to 2009-10 dollars by applying ACIL's escalation rate of 100% of CPI of 2.5% per annum.

FOM and VOM for geothermal and biomass are calculated as the average of the costs for these plants as listed in AEO 2007 and AEO 2008, in A$2009-10. The FOM and VOM costs used in the calculation of LRMC are shown in Table 12 below.

Table 12: FOM and VOM used in the 2009-10 tariff year LRMC calculation

	FOM (2009-10$/MW/year)	VOM (2009-10$/MWh)
Supercritical Black Coal	42,025	1.26
Brown Coal	42,025	1.26
CCGT	13,448	5.10
OCGT	7,880	7.88
Wind	42,025	0.00
Hydro	52,531	7.35
Geothermal	54,965	0.00
Biomass	153,638	4.60

Again, we recognise that the conditions in the U.S. that give rise to the FOM and VOM costs listed for geothermal and biomass generators in AEO may differ materially from those in Australia. Therefore, we invite submissions on the FOM and VOM costs likely to pertain for renewable electricity generation technologies in Australia over the LRMC modelling horizon, and will consider this data for inclusion in the final calculation of LRMC.

Thermal efficiencies and auxiliaries

The thermal efficiency factors and internal energy consumption (auxiliary) of the coal and gas plant used in the 2009-10 tariff year LRMC modelling have been taken from the ACIL 2007 report. They are shown in Table 13 below. ACIL provides the same estimate of thermal efficiency and auxiliary in their 2007 and 2008 reports. Thermal efficiencies for geothermal and biomass are calculated by first taking the average of their respective heat rates provided in AEO 2007 and AEO 2008, and then converting these to thermal efficiencies.[47]

47 AEO heat rates are given in Btu/kWh. First convert to GJ/MWh and then to thermal efficiency (%). Conversion 1: Heat Rate (GJ/MWh) = (Btu/kWh)*1.055056/1000. Conversion 2: Efficiency (%) = 3.6 / Heat Rate (GJ/MWh).

Table 13: Thermal efficiency and auxiliary factors used in the 2009-10 LRMC calculation

Plant type	Thermal efficiency	Auxiliaries
Supercritical Black Coal	42%	7.5%
CCGT	52%	2.4%
OCGT	31%	2.0%
Wind	Not applicable	0%
Hydro	Not applicable	0%
Geothermal	10%	0%
Biomass	38%	0%

Plant availability

The plant availability factors used for each type of plant in the LRMC modelling, along with the source of the input, are shown in Table 14 below. The availability factors for fossil-based generation plant used in the LRMC analysis of the 2009-10 tariff year are the same as those used in the 2008-09 tariff year analysis.

Table 14: Availability factors used in the LRMC modelling

	Availability factor	Data source
Supercritical Black Coal	91.78%	ANTS
Brown Coal	90.43%	ANTS
OCGT	97%	ACIL 2008
CCGT	90.99%	ANTS
Wind	93.40%	ANTS
Hydro	92.20%	ANTS
Geothermal	90%	CRA assumption
Biomass	85%	CRA assumption

Availability factors for geothermal and biomass plants are based on CRA assumptions, given the lack of publicly available information that has received widespread acceptance in Australia. We believe the availability of these plants will be lower than for CCGT, OCGT and coal plant due to the uncertainty associated with being relatively newly-established technologies.

WACC

CEMOS uses the pre-tax real weighted average cost of capital (WACC) in two ways:

- The generation capital costs in the model are annualised using the WACC; and
- When the model optimises total costs (including fuel cost or generator offer costs, annualised capital costs, the cost of unserved energy, and O&M costs), all future costs are discounted to the first year (2007) using the WACC.

Changing the WACC will affect future investment. For example increasing the WACC will increase annualised capital costs, which in turn discourages investment, especially capital intensive base-load investment. The WACC is assumed to be 9.2 per cent as reported in the ACIL 2007 Report. WACC assumptions are shown in Table 15 below.

Table 15: WACC assumptions

Parameter	Value
Input parameters	
Liabilities	100%
Debt	60%
Equity	40%
Risk-free rate of return	5.70%
Risk premium	6.00%
Market rate of return	11.70%
Corporate tax rate	30%
Effective tax rate	22.50%
Debt basis point premium	200
Cost of debt	7.70%
Gamma	0.5
Asset beta	0.8
Debt beta	0.16
Equity beta	1.75
Required return on equity	16.21
Inflation	2.50%
WACC values	
Post tax nominal WACC	9.25%

Parameter	Value
Post tax real WACC	6.58%
Pre-tax nominal WACC	11.93%
Pre-tax real WACC	**9.20%**

Source: ACIL 2007 Report, page 125

Project life

The LRMC calculation for the 2009-10 tariff year uses a project life of 30 years for all types of generation plants. This is the same value as used in the 2008-09 tariff year calculation.

Other inputs and modelling assumptions

Other data input sources used for the analysis are as follows:

- Future electricity demand projections as detailed by NEMMCO;[48]
- Generator outage statistics based on Energy Supply Association of Australia estimates;
- Current and announced environmental schemes are sourced from multiple sources:
  - The current Mandatory Renewable Energy Target (MRET) scheme www.climatechange.gov.au/renewabletarget/mret.html
  - The new expanded national Renewable Energy Target (NRET) scheme www.climatechange.gov.au/renewabletarget/index.html
  - Department of Energy, Utilities and Sustainability, NSW Renewable Energy Target (NRET), November 2006 www.deus.nsw.gov.au/Energy/Renewable%20Energy/Renewable%20Energy.asp
  - Queensland Government ClimateSmart 2050: Queensland climate change strategy, 2007 www.climatechange.qld.gov.au/response/taking_action.html
  - Victorian Renewable Energy Target (VRET) scheme www.esc.vic.gov.au/public/VRET

48 *Australia's National Electricity Market 2008 Energy and Demand Projections*, Summary Report, NEMMCO, July 2008.

- National emissions trading scheme www.climatechange.gov.au/emissionstrading/index.html

- ESAA submission to the Garnaut Climate Change Review, incorporating a report of ACIL Tasman modelling of the impact of an emissions trading scheme on the energy supply industry, 23 July 2008 www.esaa.com.au/images/stories/Report/20080723esaaatreport.pdf

All model runs are based on what we have called a business as usual (BAU) scenario, which has the following assumptions:

- Medium demand growth projections assuming average weather condition, i.e. 50% probability of exceedance (POE) level load.[49] No extreme peaks, such as 10% POE peaks, or water shortages have been modelled.

- Continuation of the New South Wales Greenhouse Gas Reduction Scheme (GGAS) and Queensland 13% Gas Scheme, and introduction of increased national Renewable Energy Targets and an Emissions Trading Scheme, but discontinuation of the Victorian VRET scheme once the increased national Renewable Energy Targets are in place.

Further details on the input assumptions are available in Appendix F.

The input assumptions are developed considering the following factors:

- The data sources are taken from reputable bodies that are available in the public domain. For instance, ACIL has been extensively used as a source for fuel prices, capital costs and generator marginal costs by NEMMCO for the national transmission studies;

- To the extent possible, we have used Australian data sources – for instance, capital cost estimates developed by ACIL for black and brown coal available in Australia; and

- In cases where non-Australian data sources such as capital costs for renewable technologies are used, we have used reputable sources such as the US Energy Information Administration's *Annual Energy Outlook 2007* (AEO),[50] and have ensured that appropriate assumptions are used to translate AEO overnight capital cost (US dollars) estimates into Australian dollars to render these consistent with ACIL estimates for other technologies. These assumptions include formulae for exposure to foreign exchange, foreign exchange rate and construction time.

---

49 This is a measure developed by NEMMCO to capture weather-related factors.

50 US Energy Information Administration, *Annual Energy Outlook, 2007*, DOE/EIA 0554, April 2007 www.eia.doe.gov/oiaf/aeo

3.2.13. LRMC results

Given the uncertainties regarding the introduction of the new national RET and ETS, Table 16 below summarises the LRMC of energy for 2009-10 under four scenarios:

- No new national RET (old MRET only) and no ETS – This is not seen as a realistic case for 2009-10 and was calculated simply to allow assessment of the change in LRMC absent any change in policy settings.
- New national RET and no ETS – This is also not seen as a realistic case given the government's stated commitment to the ETS, and is presented solely to allow disaggregation of the impacts of the two new policy settings on LRMC.
- New national RET and ETS with 10% emissions reduction carbon price – This is considered to be a possible outcome, but not the most likely or representative.
- New national RET and ETS with 20% emissions reduction carbon price – This is considered to be the most likely and representative outcome given the Federal Government's stated commitment to both policies, and the recommendations of the Garnaut Climate Change Review and other recent assessments of the level of carbon emissions reduction that will be needed to avert materially detrimental climate change.

The technology inputs to all four scenarios are the same, except for the applicable price for carbon.

The scenario that is considered to be the most likely and representative scenario is the new national RET and 20% ETS emissions reduction carbon price scenario. This is highlighted in bold in Table 16 below, and is the scenario that is taken forward in the BRCI calculations in this report.

Table 16: The LRMC of energy

Scenario	2009-10 LRMC ($/MWh)
No new national RET (old MRET only) and no ETS	43.62
New national RET and no ETS	43.62
New national RET and 10% ETS emissions reduction carbon price	52.91
New national RET and 20% ETS emissions reduction carbon price	**52.92**

Source: CRA analysis

The results show that the LRMC is virtually the same for (a) the two scenarios that have no ETS (i.e. with or without new national RET), and (b) the two scenarios that have new national RET and ETS (i.e. the 10% and 20% ETS scenarios).

In the case of the scenarios without ETS, this is because the new national RET is assumed to commence in 2011, and therefore does not affect the required generation mix of 2009-10 at all, though it does affect the plant and generation mix of 2017-18 to a minor extent, as the difference in the required amount of renewable energy increases over the years.

In the case of the two new national RET plus ETS scenarios the very small difference in LRMC is due to the fact that the carbon price starts off the same in both cases and diverges relatively slowly over the years included in the forecast horizon. The difference in the permit prices over this period is simply not great enough to significantly change the change the least cost physical plant deployment. To a significant extent this is product of the greenfield perspective. In the greenfield approach a very significant proportion of the entire generation system is assumed to be installed in the first year of the analysis period. This high proportion of capacity then influences the LRMC significantly. Although operating costs are higher in the 20% case, these differences grow relatively slowly over the forecast horizon (see Table 4) and exert only a relatively modest impact on the optimal capacity mix and dispatch of the 20% case as compared to the 10% case.

Table 17 and Table 18 compare the installed capacity and electricity generation mix of the Old MRET and New RET only cases and the New RET and 10% vs 20% carbon reduction prices, respectively. The tables show the similarity of the installed capacity and generation mix of the Old MRET and New RET only cases and the New RET and 10% vs 20% carbon reduction price cases.

Table 17: Comparison of installed capacity and generation in Old MRET only and New RET only cases

	2009-10				2017-18			
	Old MRET only		New MRET only		Old MRET only		New MRET only	
	MW	*GWh*	*MW*	*GWh*	*MW*	*GWh*	*MW*	*GWh*
Total	9,401	56,930	9,401	56,930	13,091	70,562	13,154	70,208
% by plant type								
Biomass					0.8%	1.1%	0.8%	1.1%
CCGT	22.1%	10.3%	22.1%	10.3%	30.4%	15.7%	31.0%	15.9%
Geothermal	4.8%	6.2%	4.8%	6.2%	3.4%	5.0%	3.4%	5.0%
OCGT	11.8%	2.1%	11.8%	2.1%	13.5%	2.0%	13.0%	1.9%
Small Hydro							0.6%	0.3%
SC Black Coal	61.3%	81.5%	61.3$	81.5%	50.6%	75.5%	49.8%	75.1%
Wind					1.3%	0.6%	1.3%	0.6%

Table 18: Comparison of installed capacity and generation in New RET & 10% carbon reduction price with New RET & 20% carbon reduction price cases

	2009-10				2017-18			
	New RET & 10%Carbon		New RET & 20%Carbon		New RET & 10%Carbon		New RET & 20%Carbon	
	MW	***GWh***	***MW***	***GWh***	***MW***	***GWh***	***MW***	***GWh***
Total	9,415	62,021	9,415	62,007	12,455	69,847	12,436	69,678
% by plant type								
Biomass					0.9%	1.1%	0.9%	1.1%
CCGT	79.3%	91.9%	79.4%	91.9%	78.0%	90.7%	75.7%	90.4%
Geothermal	4.8%	5.7%	4.8%	5.7%	3.6%	5.1%	3.6%	5.1%
OCGT	15.9%	2.4%&	15.9%	2.4%	15.5%	2.2%	17.8%	2.4%
Small Hydro					0.7%	0.3%	0.7%	0.3%
SC Black Coal								
Wind					1.3%	0.6%	1.4%	0.6%

We believe that it is appropriate to include the new national RET and the 20% ETS in the calculation of the LRMC because the LRMC is meant to provide a representation of the cost of the optimal plant to meet demand over the longer term. It is the explicit reference to the longer term that differentiates the LRMC from the energy purchase cost, which is meant to reflect the actual costs that retailers will pay for energy in the targeted tariff year. While the impact of these two policies on forward contract prices for 2009-10 may be modest, their impact on the optimum plant mix is likely to be profound as compared to the business as usual case (represented here by the Old MRET only case), particularly when analysed from a greenfield perspective.

3.3. COST OF PURCHASING ENERGY

This section considers the cost of purchasing energy to supply Queensland's NEM load in 2009-10. Consideration of the cost of purchasing energy is a required input to the BRCI under Sub-section 92(1) of the Act.

3.3.1. Conceptual comparison between the LRMC and actual costs

The LRMC of energy is meant to define the average cost over the long term of supplying incremental energy requirements. Investors must expect that their investments will be commercially viable or they would not invest. Therefore, it is reasonable to assume that a competitive market will produce price outcomes that align with the LRMC over the long term.

Prices in the short term, however, will be dominated by existing market conditions, which could reflect a period of supply out of sync with demand (either too high or too low). Therefore, at any point in time, the actual energy purchase costs as incurred by a retailer may differ from the LRMC due to factors such as variations in supply and demand conditions, pre-existing hedge portfolios, and ever changing expectations about the future (including expectations regarding fuel costs, environmental regulation, technology cost, performance characteristics, load developments, and so forth). Each retailer manages its risk through hedge contracting and pool purchasing strategies, among other means. Therefore, a retailer's costs may be higher or lower than the estimated LRMC in any given year.

In addition, due to the lumpy nature of investment in power stations and various policy constraints, the observed capacity mix will likely differ from the idealised greenfield capacity mix. Also, the capacity mix will be determined by past decisions where the historic technology costs for power stations may have been different from the ones assumed in the forward looking LRMC analysis. These issues also have implications for generator bidding.

These deviations can be significant. As noted above, Sub-section 92(1) of the Act requires that "*the cost of energy must reflect ... the likely total of the costs to be incurred ... to purchase energy*". This is interpreted to mean that at least some regard must be had with respect to actual prices in the short-term, as these will have an influence on "*the likely total of the costs to be incurred … to purchase energy*".

3.3.2. Approach to estimating the actual cost of purchasing energy

As was the case in our previous calculation of the BRCI for 2008-09, the approach that CRA has used to estimate the cost of purchasing energy for the purposes of calculating the BRCI for 2009-10 is to calculate a benchmark price that a prudent and efficient retailer should be able to match, given reasonable purchasing decisions and risk policies. The approach is not intended to replicate the actual purchasing decisions or the actual risk policies of any particular retailer. It is, however, conservative, and will be expected to result in some over-contracted positions. The approach involves:

- Determining how much contract volume is purchased and the time periods over which these purchases take place; and
- Applying benchmark prices to cost these purchases.

Use of contract price data from d-cypha Trade

Actual contract pricing is confidential, so the approach relies on contract prices published by d-cypha Trade, actual historic pool prices, and forecasts of pool prices.

Data published by d-cypha Trade has been used because it represents actual contract price settlements in the NEM. Data from the other major source of contract prices, the Australian Financial Markets Association (AFMA), is based on a survey of participants about the price that they would be prepared to buy and sell particular products. It does not represent actual traded prices. In addition, d-cypha Trade also publishes prices for cap contracts, which AFMA does not.

The d-cypha Trade data does have some limitations, including the fact that it is based on the futures contract market which generally trades small volume contracts. Retailers and generators also enter into large volume contracts at prices that are not publicly available, and which may differ from d-cypha Trade quoted prices.

Contract volumes and portfolio strategies

Retailers purchase contracts to hedge their load. However, determining the level of contracting is complex because:

- Future load and future pricing is uncertain, but contracts must be purchased in advance;
- Retail load changes on a daily basis both in shape (load profile) and total energy required;
- There are many instruments available for retailers to use to hedge their portfolios but only the simplest have publicly available benchmark prices; and
- Spot prices are correlated with demand. This means that periods of high demand typically coincide with high spot prices, particularly at the more extreme (higher demand) range – meaning that the risks of being uncovered due to high demand are multiplied.

Hedge contract parameters

Retailers purchase hedge contracts to manage the risk of purchasing from the spot market. In general, the shape of the peak and off-peak load duration curve for each quarter determines the mix of contracts that a retailer will purchase. The objective for a retailer is to purchase contracts that match its load as closely as possible so that it is not exposed to the spot market during potentially high-priced peak periods and it is not over-contracted during off-peak periods when spot prices are likely to be lower than contract prices.

While meeting these objectives is not possible all of the time, the position that a retailer will take depends on their appetite for risk – generally, although not always, higher levels of contracting lead to higher average energy costs but a narrower range of potential energy cost outcomes, thereby offering protection from extreme prices in the spot market.

The criteria shown in Table 19 below to determine the volume of hedge contracts that a retailer would purchase each quarter were used in the calculation of the BRCI for 2008-09, and continue to be used in the calculation of the BRCI for 2009-10. These benchmarks represent prudent levels of contracting and are based on CRA's experience in the electricity industry.

Table 19: Criteria used to purchase hedge contracts for Queensland load

Contract type	Criteria
Flat Swaps	80th Percentile of Off Peak Load
Peak Swaps	90th Percentile of Peak Load
$300 Caps	105% of Maximum Peak Load

Source: CRA analysis

Timing of purchasing decisions

A prudent retailer purchases its hedges over time, building up its portfolio slowly rather than attempting to purchase all its required contracts in one block immediately prior to the contract period. Purchasing in one block is likely to increase the cost of hedging by driving up the forward curve for contracts.

The timing of contract purchases is strongly influenced by the degree of certainty regarding the volume and shape of the retail load. For the load of customers that have accepted a fixed term market contract with a retailer, the retailer will generally purchase energy contract cover for the length of the retail contract, prior to the commencement of the retail contract, to ensure it does not have a net short position. However, for a retailer, the forecast load of customers on regulated tariffs or market contracts that are not of fixed length is more uncertain since, at any point in the future, customers can elect to remain on (or revert to) the regulated tariff, accept a market contract with the local retailer or accept a market contract with a competing retailer. Moving between a regulated tariff and a market contract without switching retailer does not change the retailer's load; this only changes when customers switch between retailers.

The Act requires the cost of energy to be calculated for the total NEM load for the State, yet the purchasing strategies can be very different depending on whether they are to cover the load of customers on fixed term market contracts, or market contracts that are not fixed term, or regulated tariffs. Because of the difficulty that would be inherent in defining and assessing separate strategies, we have assumed that the retailer's strategy for purchasing energy to meet the NEM load is the same in all cases.

In general, a retailer will have a high degree of confidence of supplying a particular proportion of its customer load. As the retailer develops greater understanding of churn rates, it can make more accurate forecasts of its customers' load over shorter time periods.

Overall, a prudent retailer is likely to purchase contracts to meet its customers' loads over a period of about two years. Purchasing contracts over a period of this length reduces the upward pressure on contract prices caused when there is a high demand for contracts in a short space of time. We have assumed that the retailer being represented in the calculation of the BRCI spreads its purchases of energy contracts for each tariff year evenly over a period of two years, in advance of the tariff year for which the energy is being hedged. We recognise that this is a simplification of a retailer's actual purchasing strategies, and that the actual strategy adopted will vary by retailer depending on its risk assessment and the degree of certainty of its customer load.

Thus, we have assumed for the purposes of calculating the BRCI that the retailer spreads its purchases of swap and cap contracts for 2009-10 evenly over the two-year period 1 July 2007 to 30 June 2009.

3.3.3. Inputs to the calculation of the cost of purchasing energy

The key inputs to the calculation of the cost of purchasing energy are as follows:

- Half-hourly load data used for the purposes of constructing a hedging strategy;
- Half-hourly load data used for the purposes of settlement;
- Contract price data published by d-cypha Trade; and
- Half-hourly NEM price data for settlement.

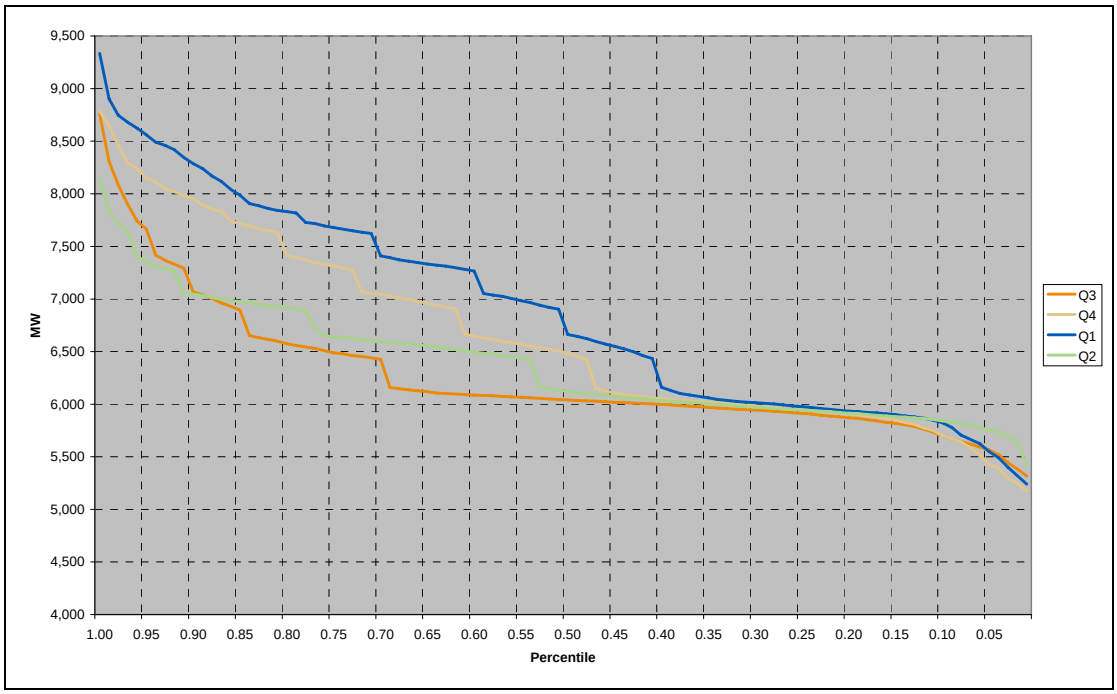
Each of these inputs is now discussed in more detail.

Half-hourly load data used for the purposes of constructing a hedging strategy

As required by the Authority, half-hourly load data that we are using for the purposes of constructing a hedging strategy for the tariff year 2009-10 represents our estimate of the whole of the Queensland load, including the load associated with directly connected customers. This data is held in our STEMM model of the NEM, from where it has been extracted for use in this estimation of the cost of purchasing energy. Our estimates of load data are based on the estimates of peak and energy from NEMMCO's 2008 Demand and Energy Projections report.[51]

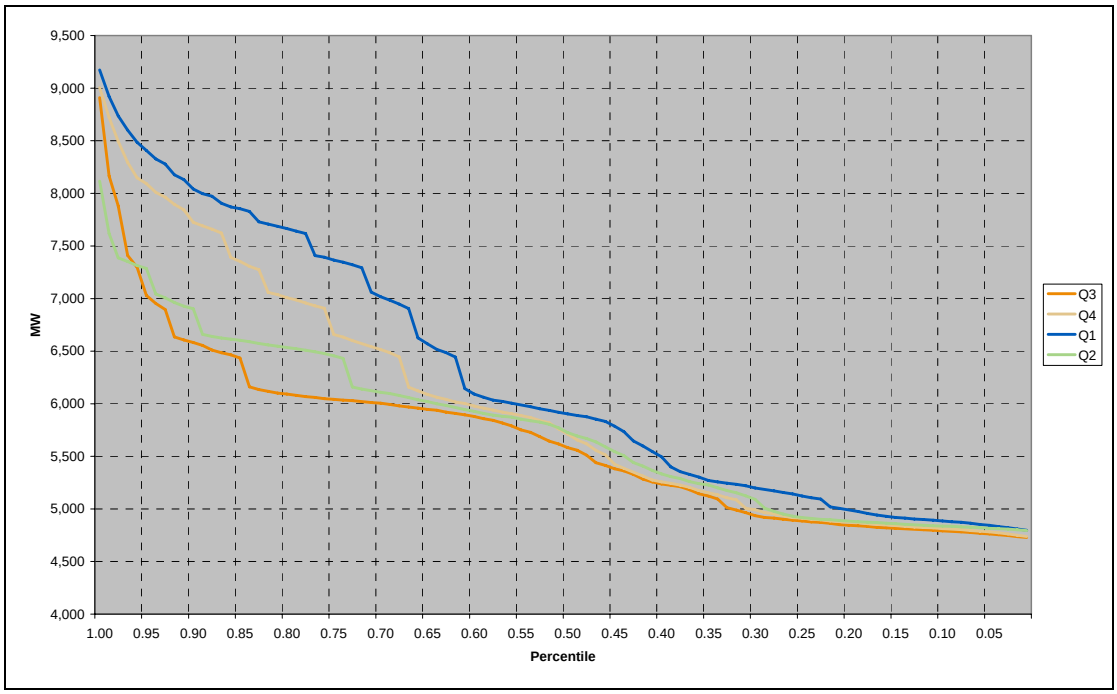
Estimated load duration curves for the total NEM load for Queensland for peak and off-peak periods for each quarter in 2009-10 are illustrated in Figure 11 and Figure 12 respectively. These figures present the half-hourly load during each period as a percentile.

Figure 11: 2009-10 Queensland load duration curve – peak



51 *Australia's National Electricity Market 2008 Energy and Demand Projections*, Summary Report, NEMMCO, July 2008.

Figure 12: 2009-10 Queensland load duration curve – off-peak



Half-hourly load data used for the purposes of settlement

The half-hourly load data used for the purposes of settlement is the same as the half-hourly load data used for the purposes of constructing a hedging strategy, as discussed immediately above.

Contract price data published by d-cypha Trade

Data published by d-cypha Trade have been used as inputs in regard to the prices of peak and flat electricity swap contracts. We have used the daily settled prices for flat swaps, peak swaps and $300 caps that were published from 1 July 2007 to the cut-off date for the finalisation of the input data for this report (this being 15 July 2008).

Half-hourly NEM price data for settlement

Half-hourly NEM price data forecasts are held in our STEMM model of the NEM, from where they have been extracted for use in this estimation of the cost of purchasing energy. The source of this data is CRA's half-hourly dispatch model, which optimises the dispatch of generators to meet expected demands.

Table 20 below summarises the NEM prices used in the analysis in this report. These prices are presented both as the time-weighted average (TWA) and the load-weighted average (LWA) for each quarter. The load used to calculate the LWA prices is the forecast half-hourly Queensland total load.

Table 20: Average spot market prices for each quarter ($/MWh)

	2009-10			
NEM prices	**Q3 2009**	**Q4 2009**	**Q1 2010**	**Q2 2010**
Time-Weighted Average (TWA) price	32.42	35.95	157.81	50.05
Load-Weighted Average (LWA) price	34.20	38.08	171.07	54.09

Source: d-Cypha Trade data and CRA analysis

3.3.4. Calculations

Processing of the half-hourly load data for the purpose of determining the swap contracts to be modelled

The various steps of processing the half-hourly load data for each tariff year are as follows:

1. Split the load data into four quarters, i.e. Q3 (July to September), Q4 (October to December), Q1 (January to March) and Q2 (April to June).

2. Within each quarter, separate the peak load from the off-peak load. Peak load corresponds to load from 07:00 hours to 22:00 hours Monday to Friday, excluding public holidays. Off-peak load corresponds to load at all other times. At this stage, the half-hourly load data has been separated into eight different divisions: peak and off-peak for each of the fourth quarters.

3. Calculate the 0 to 100 percentile load points for each of the eight divisions.[52]

Calculating swap and cap contracts to be modelled

Based on the above half-hourly load data, we modelled swap and cap contract purchases[53] as follows for each quarter of each tariff year, and for each scenario of including or excluding directly connected customers:

52 A percentile is the value of a variable below which a certain percent of observations fail. For example, the load is less than the 90% percentile load in 90% of the half-hourly periods in the data being analysed.

53 An electricity swap means an agreement between two parties to exchange the difference between a fixed price per megawatt hour (MWh) of electric energy and the NEM spot price at a stated reference node.

A peak swap is an electricity swap that only applies in peak hours. Peak hours are between 07:00 and 22:00 Monday to Friday, excluding public holidays.

- Flat swaps are purchased up to the 80th percentile of off-peak load;
- Peak swaps are purchased up to the 90th percentile of peak load; and
- $300 caps are bought beyond the cover of swaps to cover up to 105% of the maximum peak load.

Pricing of contracts

As explained in section 3.3.2 above, we have assumed for the purposes of calculating the BRCI that the retailer spreads its purchases of energy contracts for 2009-10 evenly over the two-year period 1 July 2007 to 30 June 2009.

For each contract type, we would therefore seek to price the swap and cap contracts to cover the tariff year 2009-10 based on the average of the daily settled prices quoted from 1 July 2007 to 30 June 2009. However, in this report we have only been able to use the prices for flat swaps, peak swaps and $300 caps that were published from 1 July 2007 to the cut-off date for the finalisation of the input data for this report (this being 15 July 2008).

We have included in Appendix E graphs showing the d-cypha Trade prices for each type of contract that we have considered in this analysis for the tariff year 2009-10, showing daily settled prices quoted from 1 July 2007 to 15 July 2008.

We have estimated the contract data for the period 16 July 2008 to 30 June 2009. Forecasting contract prices over the period where data is not available is difficult, particularly given the price volatility in the contract market that has been seen in the last couple of years. It is difficult to model a definitive trend that can be used to forecast future contract prices, and there is no clear best method. We have, for example, considered whether there are any historical trends in the contract prices as the date of delivery nears, or whether there is any seasonal pattern that makes contracts for the same delivery period more or less costly to purchase if they are purchased at particular times of the year. No such trend or pattern is evident.

For the purposes of this report, we have determined the average price of each contract type in the period from 16 May 2008 to 15 July 2008, and applied those prices to each day from 16 July 2008 to 30 June 2009. This approach implies that the most recent prices are the best predictor of future prices. We are not saying that we expect prices to stay exactly the same over the next eleven and a half months as they averaged over the past two months. Rather, we are saying that we have no basis for suggesting there is a better method that will more accurately predict the outturn prices over this period.

A cap is a series of half-hourly options, which places a ceiling on the price the buyer pays for electricity. The seller will compensate the buyer to the extent the NEM spot price is greater than the strike price. A $300/MWh peak cap is a cap with a strike price of $300/MWh that only applies in peak hours as defined by NEMMCO.

These contracts are the most commonly traded financial instruments in the NEM.

This estimation method will be reviewed prior to the finalisation of the BRCI calculations this year.

Table 21 below summarises the contract prices used in the analysis in this report, as derived from d-cypha Trade data.

Table 21: Average costs of energy contracts for each quarter ($/MWh)

	2009-10			
Contract type	**Q3 2009**	**Q4 2009**	**Q1 2010**	**Q2 2010**
Flat Swap	37.33	45.52	75.00	37.88
Peak Swap	49.17	66.68	108.75	45.39
$300 Cap	4.65	11.36	35.00	4.25

Source: d-Cypha Trade data and CRA analysis

Settlement of contracts and NEM prices to create the energy purchase costs

We calculated a settlement value for each half-hour for each load scenario, as the total dollar cost of the load in each half-hour, taking into account in each case the appropriate data inputs for estimated loads, prices and contract cover, as discussed above. In each case, we then added up all those settlement values across all the half-hours for each scenario and for each tariff year, and divided by the total energy (MWh) each year (the total energy being the half the sum of the half-hourly MW loads in each case). We thus obtained an average cost of purchasing energy in $/MWh for each scenario for each tariff year.

3.3.5. Application of network losses

The Queensland load data used for our analysis, which was provided to us by the Authority, is measured at the connection points between the transmission and distribution networks. These connection points are referred to as transmission nodes. NEMMCO calculates the Marginal Loss Factors (MLFs) for each transmission node on the network each financial year, and applies the appropriate MLF to the amounts of energy that are measured at each transmission node, in order to determine the amounts of energy for which settlement is undertaken in the wholesale market.

Therefore, similarly, in calculating the cost of purchasing energy for the Queensland load for the purposes of the BRCI, we also need to apply the appropriate MLF at each connection point to the load measured at that connection point.

However, we do not have the Queensland load disaggregated by transmission node. Instead, we have total Queensland load across all transmission nodes, and we have therefore applied an average MLF for the State to the total load. The average MLF for 2009-10 has been calculated from data provided by Powerlink in the 2008 Annual Planning Report,[54] as shown in Table 22 below.

Table 22: Average Marginal Loss Factor (MLF)

	2009-10
Average Marginal Loss Factor (MLF)	**1.0399**

Source: Powerlink

The calculation of the cost of purchasing energy is not affected by losses on the distribution network, because the load is measured before these losses are incurred.

3.3.6. Energy purchase costs results

Table 23 below summarises the energy purchase costs for 2009-10.

Table 23: Energy purchase costs

	2009-10
Energy purchase costs ($/MWh)	**50.96**

Source: CRA analysis

3.4. COMBINATION OF LRMC AND ENERGY PURCHASE COST RESULTS

In section 3.2, we determined the LRMC of energy, and in section 3.3 we determined the cost of purchasing energy for the tariff year 2009-10. As discussed, these are inputs to the BRCI that are required by the Act. However, since these are independent and unrelated calculations of the cost of energy, a method is required to combine these into a single energy cost that can be used as part of the BRCI.

54 Powerlink, 2008 Annual Planning Report, Table 3.8, page 34.

Our approach is to apply weightings to the LRMC and purchase cost of energy to form a single energy cost. The resulting energy cost for each year, in $/MWh, is then used as the input to the BRCI. The weightings should be determined by the policy objectives of the Government in relation to the setting of tariffs. As required by the Authority, we have adopted an equal weighting for the LRMC and purchase cost of energy factors – i.e. 50% each. These are the same weightings as were used in our previous calculation of the BRCI for 2008-09. The results of this weighting are given in Table 24 below. It is acknowledged that alternative weights could be adopted to reflect different views on the legislative intent in calculating the BRCI.

Table 24: Energy cost component of BRCI

	2009-10	
	Cost ($/MWh)	**Weighting (%)**
LRMC	52.92	50%
Energy purchase cost	50.96	50%
Energy cost component	**51.94**	

Source: CRA analysis

3.5. OTHER ENERGY COSTS

Each electricity retailer in Queensland is required to comply with the following schemes:

- The Mandatory Renewable Energy Target (MRET), and its replacement scheme; and
- The Queensland 13% gas scheme.

These schemes, which encourage increased renewable energy generation in Australia and gas-fired generation in Queensland respectively, mandate that each year each retailer either meets its target for purchasing particular types of generation or pays a penalty. The costs to a retailer of complying with these schemes are discussed below.

3.5.1. Mandatory Renewable Energy Target (MRET)

As set out in section 3.2.11 above, the Federal Government has announced that the Australia-wide Mandatory Renewable Emissions Target (MRET) is to be revised, and more details are available since the last calculation of the BRCI. The scheme currently requires that renewable energy sources account for 9,500 GWh by 2010 and remain at that level until 2020. The scheme is to be revised to ramp up to 45,000 GWh from renewable energy sources by 2020.

In the previous BRCI calculations for 2008-09 we forecast the renewable energy target for 2009 to be 8,100 GWh, based on current MRET forecasts, and we have no reason to change that target. On the same basis, we are projecting the renewable energy target to be 8,747 GWh for 2010. As shown in Table 6 above, we are suggesting that the target will then ramp up from 2011, after the end of tariff year 2009-10 (Table 6 shows this as a partial ramp up in the financial year 2010-11.)

The annual targets for renewable energy are allocated proportionally to each electricity retailer and wholesale buyer using a factor called the Renewable Power Percentage (RPP). The RPP is simply each year's renewable energy target divided by the corresponding annual load forecast. The RPP is published by 31 March each year as an amendment to the *Renewable Energy (Electricity) Regulations*. The RPP for 2008 is 3.14%. Based on the above energy targets, we are estimating the RPP for 2009 to be 3.59%, and for 2010 to be 3.72%.

Each retailer can either purchase (or generate) Renewable Energy Certificates (RECs) to cover this liability, or pay the penalty of $40/MWh for any shortfalls in RECs relative to its liability.

To determine the costs to a retailer of complying with the MRET scheme, weekly market prices for RECs published by the Australian Financial Markets Association (AFMA) have been used. This approach is the same as that used in our report last year on the BRCI for 2008-09. Prices are quoted for calendar year periods.

Based on AFMA data published up to the cut-off date for data for this report, that being 15 July 2008, the average REC price is $44.61 for 2009 and $58.11 for 2010.

Multiplying the average REC price by the estimated RPP for each of 2009 and 2010 gives an overall cost of compliance with the Renewable Energy Target requirements of $1.60/MWh for 2009 and $2.16/MWh for 2010. Averaging those results by weighting of the component of 2009-10 load that is in each of 2009 and 2010 provides an overall result that the cost of complying with the Renewable Energy Target requirements is estimated to be **$1.88/MWh** in 2009-10.

3.5.2. Queensland 13% Gas Scheme

In 2005, the Queensland Government implemented a scheme whereby liable parties (i.e. retailers) are required to source at least 13% of their electricity from gas fired generation. The design of the scheme is similar to the Commonwealth MRET scheme. Accredited generators (gas-fired generators that support Queensland electricity load) create and sell Gas Electricity Certificates (GECs) to liable parties for each MWh generated. If a liable party does not meet its annual liability by the compliance date, it is required to pay a penalty. The penalty is calculated each year according to a formula specified in the Act.

For retailers in Queensland, the cost of purchasing energy includes the cost of purchasing GECs for 13% of their retail load. The current price for GECs in Queensland reflects the level of supply and demand for GECs.

There are two methods which we have considered for calculating GEC prices for the BRCI calculation. They can be based either on penalty prices, or on prices for trades, which have been published by AFMA since 21 February 2007.

In our original calculation of the BRCI for 2007-08, quoted prices were not yet available, and therefore we used penalty prices by default.

When we then calculated the BRCI for 2008-09, and also at the same time needed to re-calculate the BRCI for 2007-08, we considered whether we should continue to estimate the prices of GECs based on penalty prices, or alternatively whether we should start to base the pricing of GECs on prices for trades which have been published by AFMA. At that time, if we had used quoted prices, we would have had only a small number of data points on which to base the GEC price for 2007-08, and this would therefore not have been a robust basis on which to estimate the cost of compliance with the Queensland 13% Gas Scheme in 2008-09. We needed a consistent approach for calculating the GEC prices for the two tariff years 2007-08 and 2008-09, and therefore we estimated the prices of GECs based on penalty prices rather than on AFMA-quoted prices for both 2007-08 and 2008-09.

At the time of this calculation for 2007-08 and 2008-09, we recommended a transition to using market quoted prices rather than penalty prices in future years. While we could now follow that recommendation and base the GEC prices for 2009-10 market quoted prices, it is not clear whether this would represent a change in calculation framework. On the one hand, it could be said that the calculation method is not consistent between 2008-09 and 2009-10 if the calculation for one year is based on penalty prices and the calculation for the other year is based on prices for trades published by AFMA. On the other hand, it could be said that the change is simply to accommodate the most recent data available for estimating GEC prices, and the framework to estimate the retailers' costs of compliance with the Queensland 13% Gas Scheme is unchanged – it continues to be based on the best estimate of GEC prices that is available at the time.

Penalty price calculation: Based on CPI inflation to date and the forecasts for CPI shown in section 2.11.1 above, a penalty price calculation would see GEC prices now estimated at $18.38 in 2009-10. GECs account for 13% of retail load, so the average cost to a retailer calculated on this basis would be **$2.39/MWh** in 2009-10.

Calculation based on prices for trades published by AFMA: Based on AFMA data published up to the cut-off date for data for this report, that being 15 July 2008, the average GEC price is $14.50 for 2009 and $12.88 for 2010. Averaging those results by weighting of the component of 2009-10 load that is in each of 2009 and 2010 provides an overall average GEC price of $13.68 in 2009-10. GECs account for 13% of retail load, so the average cost to a retailer calculated on this basis would be **$1.78/MWh** in 2009-10.

For the purposes of this First Report we have calculated the BRCI based on the penalty price calculation, because that method is more consistent with the previous BRCI calculation framework for 2008-09, but we welcome stakeholder comment on whether it would be more appropriate to move to using prices based on trades for the calculation of 2009-10 and future years.

3.6. NEMMCO COSTS

3.6.1. Participant and FRC fees

Participant and FRC fees are fees payable to NEMMCO to cover its operational expenditure. In addition, there is a charge for FRC establishment and operation.

The approach used to estimate participant fees for 2009-10 is the same as that used previously to estimate the participant fees for 2008-09. The method is to apply a linear trend to total costs for each component of NEM fees, and the load used to determine the $/MWh fee over the period since 2004-05. The estimated NEM fees for 2009-10 are provided in Table 25 below.

Table 25: Estimated NEM fees ($/MWh)

	2009-10
NEMMCO Participant Fees	0.26
FRC Establishment and Operation	0.05
Total	**0.31**

Source: CRA analysis

3.6.2. Ancillary Services charges

NEMMCO controls key technical characteristics of the electricity system, such as frequency and voltage, through Ancillary Services (AS) including:

- Automatic generation control;
- Governor control;
- Load shedding;
- Rapid generating unit loading;
- Reactive power;
- Rapid generating unit unloading; and
- System restart.

NEMMCO sources AS on a competitive basis with generators having the option of providing energy for the wholesale market or keeping capacity in reserve for the AS market. The decision on whether to provide capacity for the AS market will to an extent depend on the opportunity cost of providing energy for the wholesale market. Therefore, AS costs should show some correlation to energy prices over time. However, while compensation to providers for AS is undertaken on a regional basis, the costs to users are spread across the NEM thereby diluting any correlation between energy prices and AS costs.

Given this, historic AS costs to users have been reviewed, in order to determine likely future AS costs. There was a discontinuity in mid 2005 due to a renegotiation of AS costs.

Our framework for estimation of AS charges for 2009-10 is based on averaging the ancillary services costs for the last 52 weeks. This is unchanged from the framework previously deployed to estimate the AS charges in calculating the BRCI for 2008-09.

On that basis, our estimate for 2009-10, based on data up to week 28 of 2008 (week ending 15 July 2008) is **$0.38/MWh**.

3.7. OVERALL SUMMARY RESULTS FOR THE COST OF ENERGY

Table 26 below shows an overall summary of the results for the cost of energy in $/MWh for 2009-10.

Table 26: Summary of the cost of energy ($/MWh)

Energy cost item	2009-10
Energy	51.94
Renewable Energy Target	1.88
Queensland 13% Gas Scheme	2.39
NEM fees	0.31
Ancillary services	0.38
Total	**56.90**

Source: CRA analysis

3.8. NEM LOAD

As discussed in section 2.3 above, the NEM load (L) for the whole of 2008 is required as the denominator to enable the calculation of the BRCI for 2009-10. The NEM load includes only the energy delivered from the transmission connection network that flows through the distribution system to customers, and *excludes* any end-user load that is directly connected to the transmission system.

The Authority has provided us with the NEM load for the period 1 January 2008 to 12 July 2008. To obtain an estimate of the full NEM load for 2008, we have estimated the total load for 2008 in accordance with the year-on-year change in load from the period 1 January 2007 to 12 July 2007 to the same period in 2008.[55] On this basis, the total NEM load for 2008 is taken in this report to be **36,436,970 MWh**.

Section 6 below shows the results of multiplying these figures for NEM load with the cost of energy for each year that was shown in Table 26 above.

55 In the comparison of we excluded 29 February 2008 as an extra leap-day, so that we were comparing like with like, i.e. the total number of days in the period 1 January to 12 July in both years should be the same, to enable a meaningful comparison to be made. We then added back in the load for 29 February 2008 to get the total estimated 2008 calendar year load.

4. RETAIL COSTS AND MARGINS

This report section considers separately:

- ***Retail costs*** – which, as discussed above, reflect the likely cost that would be incurred by an efficient entity in providing retail electricity services to Queensland customers connected to the national grid; and
- ***Retail margins*** – which an efficient entity might reasonably expect to earn from its retailing activities.

4.1. CUSTOMER NUMBERS

The Authority has not yet provided us with figures for customer numbers for calculation of the BRCI for 2009-10. For this report, we have extrapolated the number of customers for 2009-10 based on the growth rate from 2007-08 to 2008-09. This gives **1,972,493** customers for 2009-10. This estimate will be revised for the Final Decision.

These customer numbers were said to *exclude* any customers whose end-user load is directly connected to the transmission system.

4.2. RETAIL COSTS

4.2.1. Categories of retail costs

As discussed in section 2.2.3 above, the Regulation prescribes that the Authority must consider the following cost categories for the provision of customer retail services:

- Billing;
- Customer call centres;
- Credit management;
- Energy trading activities;
- Corporate overheads, including, for example, treasury functions, human relations and facilities management;
- Information technology systems; and
- Any other cost category the pricing entity considers reasonable.

Each of these categories is discussed in turn below through consideration and discussion of what activities are included in each category, and what the cost driver is in each case.

- *Billing costs*: Billing costs include the activities of validating data for billing, creating bill-ready data, printing and mailing of periodic bills. Much of the cost of billing activities comprises the fixed cost of IT systems. The variable component of the costs of billing is driven by the number of bills that are issued, which is in turn a function of the number of customers and the billing cycle (generally monthly, bi-monthly or quarterly). Each bill also generates a collection cost when the customer pays the bill.

- *Customer call centre costs*: Customer call centre costs involve some fixed costs of establishing the retailer's call centre and the systems and procedures for operation of the call centre. Staff costs make up a significant portion of ongoing operational costs. The number of required staff is directly related to the number of calls made to the call centre, which is driven by the number of customers that are served by the retailer.

- *Credit management costs*: Customers generally pay in arrears for the costs of the electricity they consume, and credit management is therefore an important issue for retailers to address, to ensure that working capital requirements and provisions for bad debt are minimised. Credit management costs include hardship and similar policies to assist customers with payment policies. The costs of credit management are largely driven by the size of the business.

- *The costs of energy trading activities*: These costs include the staff costs of engaging in energy trading, in particular personnel costs. For a given fuel (electricity or gas), these costs are driven by the size of the business, although the complexity of the electricity and gas markets differ.

- *Corporate overheads*: These include treasury functions, human relations and facilities management functions. They are generally driven by the size of the business.

- *The costs of IT systems*: IT costs are largely driven by the size of the business. For a given retail business, the gain or loss of a few customers or does not change the IT costs of the business. Instead there are step changes when the business grows substantially and a new IT architecture is needed. IT costs are not necessarily a cost category apart from other cost categories – rather, these systems support the other categories of activity – such as billing and customer call centres.

- *Other costs*: Retailers incur other costs, but these are not generally itemised – due to their small materiality as compared to the larger cost categories discussed above. These include the costs of regulatory compliance, licensing fees, ombudsman costs, and settlement validation costs. One other cost category that can be itemised separately relates to the costs of customer acquisitions, which is discussed separately in section 4.2.8 below.

In a competitive environment, a retailer's operating costs include the costs of complying with the requirements of the competitive market. These costs include the costs of interfacing with industry B2B systems, transferring customers between retailers and validating settlement of the costs of those customers, and providing customer education – through trained call centre staff with tailored scripts, web-site information and perhaps bill inserts. Many of these costs could be categorised as IT systems costs and regulatory compliance costs.

From 2007-08 onwards, retail competition was extended to all customers with the introduction of FRC from 1 July 2007. The IT systems costs and regulatory compliance costs of operating in an FRC environment are now higher than they would have been in the earlier, more limited competitive environment. These costs are separate from the costs that are incurred by electricity network operators, and which are then either borne by the network operators or passed through in network use of system charges as determined by the Authority.

4.2.2. Retail costs for a standalone retail business as against an integrated utility

The allocation of costs such as corporate costs, IT costs and overheads between distribution and retail functions in an integrated utility is generally at least somewhat open to question. Allocations are also open to question in other cases where there are multiple sources of revenue, as for instance in the case of a dual fuel retailer. In Queensland, the local retailers Sun Retail (owned by Origin Energy) and Powerdirect Australia (owned by AGL) are not affiliated with network businesses, but the remaining Government-owned retailing business, Ergon Energy Queensland, does have network business affiliation. Origin Energy and AGL both certainly have other retailing interests outside Queensland, and dual fuel interests within Queensland. The requirement in the Act that the retail costs included in the determination of the BRCI be based on an efficient retailer business that "is carried on separately from any other business" necessarily means that the retail costs used in determining the BRCI will not be the same as the actual retail costs incurred by the Queensland retailers.

Based on the above considerations, it would seem likely that actual retail costs of the local retailers in Queensland will be lower than the costs calculated in accordance with the Act, because the local retailers in Queensland will be able to share fixed costs and overheads with other business interests, whereas the standalone retail business described in the Act has no such other business interests.

4.2.3. Discussion of fixed and variable components of retail costs

Frontier Economics considered in a report to IPART[56] to what extent retail operating costs were fixed vs. variable. Frontier Economics stated:

56 *Mass Market New Entrant Retail Costs and Retail Margin*, prepared for IPART, Frontier Economics, March 2007.

> *It makes sense that retail operating costs are predominantly fixed. A large component of these costs is related to the systems that an efficient mass market retailer requires, including IT systems – such as billing and revenue collection systems and customer information systems – as well as customer service systems, including those required for the effective operation of call centres. The costs of establishing these systems are largely fixed costs. Once these systems are in place, the costs that vary with customer numbers – which are primarily a function of processing customers' bills, responding to customer queries, etc – are comparatively small.*
>
> *Another way of looking at this is to consider the major elements of operating costs, as reported by the retailers. …, the four major elements of operating costs reported by the retailers are corporate overheads, billing and revenue collection costs, customer information systems and call centre costs. There is reason to think that each of these four costs elements is predominantly fixed. Corporate overheads, for instance, will not vary significantly with customer numbers. Billing and revenue collection costs and customer information system costs are both likely to consist predominantly of the IT systems required for the retailer to operate effectively. These are predominantly fixed. Finally, while call centre costs are likely to have a significant variable component, because the number of staff required in a call centre is largely dependent on the number of calls the centre receives, there is also likely to be a significant fixed component associated with the development of the systems necessary for the effective operation of a call centre.*

Frontier Economics noted that some regulators were of the view that retail operating costs are predominantly fixed,[57] while other regulators have stated a view that retail operating costs are predominantly variable.[58]

Frontier Economics noted that the uncertainty regarding the fixed or variable nature of retail operating costs is due in part to the nature of retail costs; the Tasmanian Energy Regulator somewhat explained the issue by pointing out that many of the costs associated with electricity retailing are not completely fixed or truly variable. For instance, the costs of IT systems "tend to be incurred in relatively long flat steps" rather than varying directly with customer numbers[59]. This being the case, differences in understanding whether these costs should be treated as fixed or variable are to be expected.

---

57 See for instance *Review of the Effectiveness of Full Retail Competition for Electricity*, Special Investigation, Final Report, Essential Services Commission Victoria, September 2002.

58 See for instance *Reviews of Public Electricity Suppliers 1998 to 2000*, Supply Price Control Review, Final Proposals, Ofgem, December 1999.

59 *Investigation of Prices for Electricity Distribution Services and Retail Tariffs on Mainland Tasmania*, Final Report and Proposed Maximum Prices, Office of the Tasmania Energy Regulator, September 2003.

Frontier Economics recommended that the retail operating costs of a retailer operating to scale should be treated as 75% fixed (on a per company basis – representing the fixed costs of IT systems, corporate overheads, and other costs that do not vary significantly with customer numbers), and 25% variable (representing costs incurred on a per customer basis such as bill production and revenue collection costs). As recommended by Frontier Economics, the driver of the variable costs is customer numbers, and specifically not the amounts of energy consumed by each customer – although Frontier Economics did report the variable costs as $/MWh equivalents, based on average customer consumption levels.

IPART accepted the recommendation of Frontier Economics that the retail operating costs of a retailer operating to scale should be treated as 75% fixed and 25% variable.[60]

4.2.4. Approach to estimating retail costs for the BRCI calculations

If the data were available, the best means of estimating the retail operating costs on a per customer basis would be to segment the customer base and to identify the specific costs that are incurred in serving each segment in each cost category. These could all then be added together with the fixed costs to give total retail costs for the electricity retailer. It would appear that this approach is envisaged in the Act.

However, in the absence of information on segmentation of the customer base and data on how the retail operating costs for the various segments, such an approach based on segmentation is not practical. This being the case, the approach that has been taken to estimate retail costs in the calculation of the BRCI is based on benchmarking total retail costs across a retailer rather than calculating a bottom-up set of costs by customer segment and cost category.

In previous years' calculations of the BRCI, analysis was undertaken of the regulatory decisions on retail costs that have been made in other Australian jurisdictions and other publicly available sources of data on retail operating costs, and the findings from the analysis were applied to Queensland.

A view was taken that a reasonable value for retail operating costs for a retailer operating to scale in an FRC environment (excluding customer acquisition costs or allowance for loss of scale) was a value of $75/customer which was estimated for 2006-07, and then adjusted for inflation in following years.

60 *Promoting Retail Competition and Investment in the NSW Electricity Industry – Regulated Electricity Retail Tariffs and Charges for Small Customers 2007 to 2010*, Final Report and Determination, IPART, June 2007.

4.2.5. Submissions to the Authority's Interim Consultation Notice regarding retail operating costs excluding customer acquisition costs

Some of the relevant submissions to the Authority's Interim Consultation Notice regarding retail operating costs are summarised here. This summary excludes comments related to the Authority's substitution of forecast data with updated data when re-calculating the BRCI for 2007-08, as no re-calculation is now being undertaken, and also excludes comments related to customer acquisition costs, which are discussed separately in section 4.2.8 below.

- AGL stated that it continued to support the benchmarking approach and that it remained of the view that higher capital costs require either a higher allowance for margin or a higher increase in operating costs and wholesale energy costs.

- Australian Power & Gas (APG) stated that it maintained the view that retail costs have been significantly understated in the previous 2008-09 BRCI determination. It stated that the cost of capital / funding to create and sustain a retailer in Queensland is significant and needs to be captured in future determinations. APG also noted that retailers in Queensland are required to administer various customer concession schemes and government community schemes including the Electricity Pensioner Energy Concession Rebate, Reticulated Natural Gas Rebate, Home Energy Emergency Assistance, and Community Ambulance Cover. APG stated that the administration of these schemes adds significant cost, and these administration costs need to be taken into account in the BRCI determination. APG also noted that in the future the introduction of the National Emissions Trading Scheme will impact retail costs and margins.

- Origin Energy stated that it believes the approach of calculating retail costs used in the calculation of the BRCI for 2008-09 was reasonable, i.e. based on an underlying retail operating cost and a cost associated with customer acquisition, sufficient to replace losses and therefore to retain existing economies of scale. Origin Energy also agreed that it was a reasonable approach to use the Labour Cost Index to adjust the labour component of retail operating costs and the most recent CPI calculations to adjust the non-labour components. However, Origin Energy believed that the allowed retail operating cost is too low, given that the relevant customer base includes large customers that have substantially higher costs to serve and acquire than most mass market customers in general. Origin Energy also noted the need for retailers to establish and administer government initiative schemes and increased costs through increased costs of capital.

4.2.6. Responses to submissions to the Authority's Interim Consultation Notice regarding retail operating costs excluding customer acquisition costs

The submissions broadly support the benchmarking approach, but seek to show why costs may be different in Queensland, or why there may be significant changes (such as the cost of capital) since the benchmarks were set.

The benchmarking approach does not differentiate size of customer, and that is why no additional allowance has been made for the costs of servicing very large commercial and industrial customers that are connected to distribution networks in Queensland, and indeed does not differentiate at all between the retail costs of serving residential versus business customers.

Various jurisdictions have government initiative schemes such as concession schemes which electricity retailers are required to administer, and in the benchmarking approach the costs of administering each individual scheme are not itemised or allowed a separate cost estimate. Some of the schemes, such as the Community Ambulance Cover scheme may be unique to Queensland. The Community Ambulance Cover legislation sets out that the Commissioner of State Revenue may pay an electricity retailer an administration fee for performing its functions as required. This fee is paid by the Commissioner outside the notified prices framework. Allowing recovery of the costs of this scheme within the notified prices would allow the retailers to recover the costs of administering the scheme through two different frameworks, which would not be appropriate.

It is recognised that retailers may now have higher costs of funding working capital than was previously the case. However, we have not yet seen this being considered as an issue in other regulatory decisions on electricity and gas pricing in Australia;[61] therefore any extra costs are not showing in benchmarks. On that basis, we are not currently proposing an additional allowance to cover extra working capital costs, but we leave it open to stakeholders to provide in submissions quantified data and documentary evidence of additional working capital costs that would be incurred in 2009-10 as against in previous years.

4.2.7. Conclusion on retail operating costs excluding customer acquisition costs

We conclude that a reasonable value for retail operating costs for a retailer operating to scale in an FRC environment (excluding customer acquisition costs or allowance for loss of scale) remains a value of $75/customer which was estimated for 2006-07, and then adjusted for inflation in following years. As previously, we have estimated that labour costs account for approximately 60% of total retail operating costs. We have thus used the inflation factors from section 2.11 above, applying the WPI inflation factors to 60% of the retail operating costs, and the CPI inflation factor to the remaining 40%.

This results in retail operating costs excluding customer acquisition costs being estimated at **$84.20 per customer** for 2009-10.

61 In particular, there have been recent decisions on regulated pricing from 1 July 2008 in regard to electricity in ACT and gas in SA. In neither of these determinations, did increased cost of working capital seem to be raised as an issue. In SA, Origin Energy submitted to the regulator a specific request for increased working capital, stating that “this pre-payment cycle creates an additional cost that is not incurred in the electricity market and applies only to the SA gas market”. Source: *2008 Gas Standing Contract Price Inquiry, Origin Energy Response to ESCOSA on Draft Inquiry Report and Draft Price Determination*, April 2008, page 12.

4.2.8. Customer acquisition costs

Discussion of customer acquisition costs

In a competitive market, retailers incur marketing, advertising and customer acquisition and retention costs. The amount that each retailer spends on these activities is at its own discretion. Experience in the mass-market in other Australian jurisdictions has shown that the most effective way to gain new customers is through door-knocking. Some retailers have also engaged in expensive TV and mass-circulation advertising to promote their brand names, but the effectiveness of these campaigns is not easily related to the amount spent or the media chosen. Other means of attracting and retaining customers are through direct mail campaigns, outbound telemarketing, less expensive local/neighbourhood print media and through affinity deals with partners such as credit card companies and airline frequent flyer programs. There are many ways of undertaking marketing, and each has its own cost basis.

In the past, marketing, advertising and customer acquisition and retention costs were not typically taken into account in regulatory decisions that set prices for customers that do not take a market contract, but rather remain on (or return to) supply under standard (regulated) terms and conditions. These regulatory decisions were made on the basis that retailers do not need to incur any marketing, advertising or customer acquisition and retention costs in order to serve customers that remain on (or return to) supply under standard (regulated) terms and conditions. Therefore it was not considered appropriate to include those costs.

There was also some concern that the retailers that served customers under standard tariffs were the previous monopoly incumbent retailers with 100% market share at market opening. It was considered that a successful competitive market would be best established if all retailers were able to compete equally. It was felt that allowing the incumbent retailers costs of customer acquisition and retention would be anti-competitive since new entrants who would have to self-fund their marketing campaigns would not be competing on a level playing field. On the other hand, inclusion of marketing costs would increase headroom and therefore potential competitive entry, but it would also add significantly to the margins of incumbent retailers, particularly in the early days of FRC.

Decision of IPART to allow customer acquisition costs

One notable exception was the IPART decision in 2007,[62] where for the first time customer acquisition costs were taken into account, and were explicitly calculated and incorporated in a regulatory decision to set standard (regulated) prices in an Australian jurisdiction.

62 *Promoting Retail Competition and Investment in the NSW Electricity Industry – Regulated Electricity Retail Tariffs and Charges for Small Customers 2007 to 2010*, Final Report and Determination, IPART, June 2007.

The reason why that decision took these costs into account is because the Terms of Reference for that IPART investigation and determination specified that the allowances for retail operating costs and retail margin should reflect the retail costs and retail margin of a hypothetical mass market new entrant. This represented a significant change from the approach that IPART had taken in previous determinations, where the allowances for retail operating costs and retail margin had sought to reflect the retail costs and retail margin of the actual standard retailers that supply regulated customers in NSW.

IPART's allowances for customer acquisition costs were based on its estimate of the actual cost of acquiring a customer being $200. These costs included all costs relating to marketing to new customers and the costs associated with the process of transferring customers.[63] The final allowances that IPART determined for customer acquisition costs were:[64]

- For residential customers: $29/year – based on amortisation of acquisition costs over an eight-year period of customer retention;
- For small business customers: $37/year – based on amortisation of acquisition costs over a six-year period of customer retention; and
- A weighted average of these figures for residential and small business customers gave an overall result of $30/year.

Loss of scale – an alternative approach

As noted above, the IPART allowance for customer acquisition costs is a direct consequence of the decision to base the standard tariff on the costs that would be incurred by a mass market new entrant, whereas most other jurisdictions have used the costs incurred by the incumbent retailers as the basis for setting standard tariffs, and have not included the costs of customer acquisition.

However, where new retailers enter the market, the number of customers served by the incumbent retailer on standard tariffs can be expected to decline over time. Besides any consideration of customer acquisition costs, if the number of customers served by an incumbent retailer decreases, the total cost per customer of that retailer is likely to increase due to the fact that any fixed costs will need to be amortised and recovered over a smaller customer (or sales) base.

63 IPART reported that these costs included sales overheads; credit checking; communications, stationery, information booklets and confirmation packs; data and processing, customer transfers and registrations; door to door, commission and agent costs per sale; postage; and telecommunications costs.

64 In its final decision, IPART adjusted its earlier draft decision estimates downwards by $5/year from the previous overall result of $35/year. This downwards adjustment was reported to have been made in order to account for any double counting between retailer operating costs and customer acquisition costs.

Most regulatory decisions on retail prices in Australia have not made any explicit allowance for these losses of scale. There are several possible reasons for this, which could include the following:

- It was assumed that the retailers offering standard prices would still maintain scale even with some loss of customers.
- The increase in retail costs per customer from some loss in scale was not considered to be significant.
- The allowance given for retail costs in the regulatory decisions was thought to be sufficient to cover the actual retail costs incurred even with some loss in scale.
- Even without an explicit allowance for these costs, retailers were choosing of their own accord to spend money on customer acquisition and retention and thus maintaining scale, even though this was not a requirement for serving customers on standard contracts. Therefore, there was no need for any further allowance for the costs of losing scale.

A notable exception is a previous determination of ESCOSA of standing contract retail prices for 2005-07, where explicit allowance was made for increasing operating costs to allow for loss of scale. ESCOSA stated:[65]

> *The Commission notes that a significant proportion of retail operating costs are attributable to salaries. It further notes that many of the remaining costs are fixed, and will not fall in direct proportion to the number of customers (e.g. billing system, call centre). However, the costs of these systems can be spread by AGL SA over its market contract gas and electricity customers.*

Such an allowance can be seen as an alternative approach for capturing the dynamic effects of a competitive market on the costs incurred by an incumbent retailer.

Recent decisions in ACT and SA

As noted above, the IPART decision of June 2007 was the first regulatory decision that made an allowance for customer acquisition costs in setting the standard (regulated) prices in Australia.

65 *Electricity Standing Contract Price*, Price Determination, ESCOSA, December 2004.

Recent determinations in the ACT and SA have since taken this determination into account:[66]

- A draft determination by ICRC in the ACT in 2007 proposed an allowance of $15.09/customer for customer acquisition costs.[67] This equated ICRC's draft determination of $110/customer (comprising a basic figure of $94.91 plus $15.09 customer acquisition costs), with IPART's draft determination of $110/customer (comprising a basic figure of $75 plus $35 customer acquisition costs[68]). However, in its final determination, ICRC decided not to allow any recovery of customer acquisition and retention costs in its benchmark cost base. This decision was made on the basis that ICRC believed that the negative social impact of the inclusion of such costs in this instance outweighed the need to reduce barriers to new entry. ICRC also stated that such costs could be argued to be low on a per customer basis and could be argued to be covered by the CPI allowance that was being applied to the retail operating costs.[69]

- The ICRC again confirmed its decision not to make an allowance for customer acquisition costs in its draft[70] and final[71] decisions in 2008, notwithstanding strong inputs from stakeholders in submissions requesting and arguing that the ICRC should make such an allowance.

66 A further recent determination by OTTER in Tasmania (September 2007) did not need to consider customer acquisition costs, because FRC has not been implemented in Tasmania.

67 *Retail Prices for Non-contestable Electricity Customers*, Draft Decision, ICRC, May 2007.

68 As noted above, in its final decision, IPART adjusted these earlier draft decision estimates downwards by $5 per customer to account for any double counting between retailer operating costs and customer acquisition costs.

69 *Retail Prices for Non-contestable Electricity Customers*, Final Decision and Price Direction, ICRC, June 2007.

70 *Retail Prices for Non-contestable Electricity Customers*, Draft Decision, ICRC, April 2008.

71 *Retail Prices for Non-contestable Electricity Customers*, Final Decision and Price Direction, ICRC, June 2008.

- In SA in 2007, ESCOSA departed from its previous position where allowance had been made for increasing operating costs to allow for loss of scale. Instead, ESCOSA set an allowance for retail operating costs that reduces in real terms by 4.1% per annum. ESCOSA justified this on the basis of AGL SA's projected reductions in operating costs, notwithstanding any loss of scale.[72] ESCOSA also declined to make an additional allowance for customer acquisition costs over and above the allowance it was already making for retail operating costs. ESCOSA made this decision based on its assessment that its allowance for retail operating costs was already sufficient to include customer acquisition costs. In making this decision, ESCOSA took into account actual cost information provided by AGL SA on its overall retail operating costs, including customer acquisition costs.[73]

- In a determination of gas standing contract prices in 2008, ESCOSA again did not provide an allowance for acquiring new customers in the retail operating cost allowance. ESCOSA's basis for its decision-making was that it expected efficiencies in Origin Energy's operations to limit any increase in overall retail operating costs – ESCOSA stated that cost efficiencies and productivity growth could be expected to at least offset any real increases in retail operating costs for each year of the price path period.[74]

AEMC draft findings

In its review of the effectiveness of competition in South Australia, the AEMC has reported that in its First Draft Report it is "incorporating an explicit allowance of between $80 and $150 for customer acquisition costs".[75]

Previous application to the calculation of the BRCI in Queensland for 2008-09

The Authority's Final Decision on the BRCI for 2008-09 made an allowance for customer acquisition and retention costs to maintain scale.

---

72 While not stated directly by ESCOSA, it would seem to reflect a change by ESCOSA from consideration of AGL SA's position in SA in isolation to having regard to AGL's overall cost structure as a national retailer. This in turn would be consistent with AGL's own moves to consolidate its systems nationally and to increase its efficiency nationally through investment in IT systems as a part of Project Phoenix.

73 *2007 Review of Retail Electricity Price Path*, Final Inquiry Report & Price Determination (Public version), ESCOSA, November 2007.

74 *2008 Gas Standing Contract Price Path Inquiry*, Final Inquiry Report & Final Price Determination, ESCOSA, June 2008.

75 *Review of the Effectiveness of Competition in Electricity and Gas Retail Markets in South Australia*, AEMC, First Draft Report, 4 July 2008, page 35.

IPART at the time provided the only available benchmark. IPART was considering a new entrant, where all customers have to be acquired, and therefore its calculated extra allowance per customer was added to all customers. However, in calculating the BRCI, the retailer under consideration is not a new entrant. Rather it is already at scale, and the intention of the allowance is to enable the retailer to retain the same customers and the same scale. Therefore, the acquisition and retention costs would only be incurred to win or retain customers to the extent that other retailers may be able to win them away from the retailer under consideration. Thus the acquisition and retention costs were directly related to the extent of competitive activity and churn rates.

The final allowances that IPART determined for customer acquisition costs were:

- For residential customers: $29/year – based on amortisation of acquisition costs over an eight-year period of customer retention;
- For small business customers: $37/year – based on amortisation of acquisition costs over a six-year period of customer retention; and
- A weighted average of these figures for residential and small business customers gave an overall result of $30/year.[76]

IPART annualised the customer acquisition costs based on assumptions of the number of years for which acquired customers would be retained. In assessing the BRCI for 2008-09, we commented that there was not yet enough data available to estimate for how many years customers acquired under FRC in Queensland will be retained, and our analysis of the requirements for the calculation of the BRCI also suggested that costs should be allowed where they are occurred, and not annualised over some future uncertain period of time.

In its draft decision, IPART had estimated customer acquisition costs for 2007-08 to be $200 per acquired customer, but then in its final decision it reduced its resulting annualised cost figure per acquired customer from $35/year to $30/year. This downwards adjustment was reported to have been made in order to account for any double counting between retailer operating costs and customer acquisition costs.

Alternatively, this downward adjustment could be considered as being equivalent to customer acquisition costs being $200 * 30 / 35 = $171.43 per acquired customer in 2007-08, with adjustment for inflation in following years. This was the basis on which the BRCI allowance for customer acquisition was set for 2008-09.

We also included in the BRCI calculations for 2008-09 an allowance of $100.00 for a transfer to a market contract in 2007-08, again with adjustment for inflation in following years.

76 *Promoting Retail Competition and Investment in the NSW Electricity Industry – Regulated Electricity Retail Tariffs and Charges for Small Customers 2007 to 2010*, Final Report and Determination, IPART, June 2007.

Application to the calculation of the BRCI in Queensland for 2009-10

Carrying forward the decision from 2009-10 without amendment of costs would give the following results:

- The allowance for customer acquisition costs for switches between retailers should be $171.43 per acquired customer in 2007-08, with adjustment for inflation in following years.
- The allowance for transfer to a market contract without switch of retailer should be $100.00 in 2007-08, again with adjustment for inflation in following years.

Application of inflation

We previously estimated that labour costs account for approximately 60% of total retail operating costs. Using the inflation factors from section 2.11 above, applying the WPI inflation factors to 60% of the retail operating costs, and the CPI inflation factor to the remaining 40% would give the following results for the cost of each transfer between retailers and between contracts with the same retailer in 2009-10, if there are no changes made to the cost numbers:

- $184.45 for a transfer between retailers; and
- $107.60 for a transfer to a market contract without switch of retailer.

However, the opportunity should be taken to reassess these cost numbers, based on additional input from sources including the AEMC and submissions from stakeholders.

Numbers of customer switches and transfers

We now consider the number of customer switches and transfers to which allowances for transfers should be applied.

In our Addendum Report on the calculation of the BRCI for 2008-09, we reported that we had assessed the transfer data published by NEMMCO with the assistance of NEMMCO staff. Each transaction that is counted and reported as a completed transfer is perhaps better described as being a completed change request. Some of those change requests are changes in NMI details rather than customer transfers, and some are instructions to reverse a previous change request that may have been entered in error. We reported in the Addendum Report that we had analysed the detailed transaction data that sits behind the published transfer data and concluded that the number of actual customer transfers between retailers was smaller than we had reported in the Draft Report on the calculation of the BRCI for 2008-09.

We have now attempted again to analyse the most recent data from NEMMCO on the number of small customer transfers between retailers in Queensland. A substantial proportion of the data appears to relate to changes in NMI data that do not equate to customer transfers between retailers. As at the date of finalising this First Report, we have not reached a definitive view on the numbers of transfers that have occurred to date, and it is currently uncertain whether it is actually possible to fathom that number from the raw NEMMCO change request data statistics.

An alternative source of transfer data may be the quarterly market customer statistics published by the Authority.[77]

Whichever data source is used, it is difficult to predict now what transfers will take place in the tariff year 2009-10. We previously extrapolated that each month the number of customers transferring between retailers would be the same as in the last month for which data was available, which was noted in submissions to the Interim Consultation Notice not to be a robust estimating mechanism. Now with the earlier calculation of the BRCI for 2009-10, this approach would require us to estimate customer transfers up to two years in advance. It may be that switches will decline, given submissions to the Interim Consultation Notice that informed that some retailers that were previously active in the small customer market in Queensland are no longer active.

A further question is whether it is actually necessary for the hypothetical retailer to retain all customers that would otherwise have switched retailer in order to retain scale, given that (a) there is some natural customer growth that comes to the retailer (among other active retailers) and (b) a small number of customers can be lost without losing scale. Retaining scale does not require the number of customers to remain exactly constant.

We welcome stakeholder submissions on these matters.

Customers transferring to a market contract with their existing retailer (i.e. without change of retailer)

In our Addendum Report on the calculation of the BRCI for 2008-09, we based an estimate of the number of customers transferring to a market contract with their existing retailer on data published in South Australia.[78] Based on this data, we estimated the number of customers switching to a market contract to be 82.1% of the customers switching retailer in the first year of FRC, and 56.1% of the number of customers switching retailer in the second year of FRC.

Submissions to the Interim Consultation Notice questioned the relevance of using the South Australian data in this manner.

---

77 The statistics are published at www.qca.org.au/electricity-retail/FRC/CustomerStats.php.

78 *Performance of South Australian Energy Retail Market – 2006/07 Annual Performance Report*, ESCOSA, November 2007.

Given that we are currently uncertain of the Queensland data for switching, we also are uncertain how we might now apply a comparison based on the South Australian data.

Customer acquisition costs – approach to obtain results in this First Report

Given the uncertainties, discussed above, our approach in this First Report is to apply the inflation adjusted allowance for switches between retailer and transfers to a market contract without switch of retailer to the same number of switches and transfers as was projected in the Addendum Report for 2008-09.

Switches between retailers

- $184.45 * 217,536 / 1,972,489 = $20.34

Transfers to a market contract with the same retailer

- $107.60 * 122,032 / 1,972,489 = $6.66

These calculations will be revised as more data becomes available and we will take into account submissions from stakeholders.

4.2.9. Summary of the results for retail costs

Table 27 below shows a summary of the results for the calculation of retail costs for 2009-10.

Table 27: Summary of retail costs ($/customer)

	2009-10
Retail costs benchmark excluding customer acquisition costs (CAC)	$84.20
CAC for transfers between retailers	$20.34
CAC for transfers to a market contract with the same retailer	$6.66
Total Retail Costs ($/customer)	**$111.20**

Source: CRA analysis

Section 6 below shows the results of multiplying the retail costs for each year shown in Table 27 above with the figures for customer numbers that were given in section 4.1 above.

4.3. RETAIL MARGIN

4.3.1. Terminology

The ***gross margin*** of an electricity retailer is defined as being the retailer's retail revenue minus energy purchase costs, transmission and distribution charges, fees and levies.

Gross margin includes the retailer's operating costs, and the ***net margin*** is what remains after the retailer's operating costs are subtracted from the ***gross margin***. It is the ***net margin*** that is referred to as the "retail margin" in the Queensland instruments regarding calculation of the BRCI.

Recent regulatory decisions in Australia have considered operating costs separately from net margin, and that method of analysis has also been used in determining the BRCI for each year in this project. A view has been taken on what is an appropriate net margin for the retailer to expect in each of the two years under consideration.

Net margin is usually presented as a percentage of total revenue, and thus it is defined as gross margin minus retail operating costs, divided by total revenue. However, recent regulatory decisions in South Australia have defined net margin as a percentage of the retailer's "controllable costs", i.e. it is defined as gross margin minus retail operating costs, divided by wholesale purchase costs plus retail operating costs.[79]

Thus clarity is needed when quoting margins to understand what they represent. With that clarity, a conversion of any % value to a $/MWh figure to add to the other BRCI cost components is quite straightforward.

Retailers need to expect to earn a sufficient net margin to attract the risk capital necessary to provide an energy retailing service. What investors require by way of expected net margin will depend on various risks deemed to be inherent in the business. Over time, failure to meet or exceed these net margin expectations would be consistent with an inability of the business to sustain necessary and appropriate investment and/or to remain financially viable.[80]

---

79 *Electricity Standing Contract Price – Price Determination*, ESCOSA, December 2004, and subsequent ESCOSA determinations of electricity and gas standing contract prices have defined net margin as a percentage of the retailer's "controllable costs".

80 This discussion of net margin is based on *Electricity and Gas Standing Offers and Deemed Contracts (2004-2007)*, prepared by CRA for Energy and Security Division, Victorian Department of Infrastructure, December 2003.

Thus, the net margin is intended to provide an appropriate return for the capital that is invested in the retail business, including working capital and provision for bad debts. Determination of the appropriateness of different levels of expected net margin needs to reflect various business and industry risk factors. If the level of regulated prices is set too low, the resulting net margin could be too low to facilitate entry into the business (or expansion of activities by existing participants), impairing the realisation of the broader policy objective of supporting the development of robust competition in the retail sector over time.

In this analysis, a key issue in determining the appropriate net margin has been the risks that face the retailer. The major risks are typically volume and price risks.

- Volume risks come through customers' usages changing unpredictably, and through gains and losses of customers in the FRC environment.
- Price risks come from volatility of wholesale energy prices.

When determining the risks that are taken into account in the margin calculations, it is important to ensure that costs of risks are not missed or double counted. In particular, the approach to determining appropriate energy costs must be consistent with the net margin calculation, in regard to where compensation for risks lies.

The approach taken in this study for calculating an allowance for purchasing of energy has taken into account and specifically made an allowance for hedging costs, based on how an efficient retailer would operate in the market. However, there remains the risk that a retailer will purchase energy at a price higher or lower than the price that has been calculated here. The price that a retailer will pay for hedges will depend on many factors, including the timing of purchases. This will mean that the retailer's average purchase price will deviate from the average cost that has allowed here. Therefore, the approach in this study does not eliminate price risk for a retailer.

There is also a volume risk for the retailer. The average price is based on a historic load shape that will differ from the actual load shape for which a retailer has to purchase energy. For example, if there are high demand peaks due to hot weather that lead to correspondingly high pool and contract prices, a retailer will incur a higher average purchase cost than if the load shape is flatter due to milder weather.

4.3.2. Conclusion on retail margin for 2008-09

Based on a benchmarking approach, a retail margin of 5% of revenue was deemed to be an appropriate retail margin for 2008-09.

4.3.3. Conclusion on retail margin for 2009-10

In order to determine whether the retail margin should be changed in 2009-10 from the previous year's value of 5%, we have considered what if anything has changed in the risk profile of the retailer that is considered in the BRCI framework between 2008-09 and 2009-10. We have concluded that there has been no particular change in the characteristics of the retailer. We believe that the margin that the retailer would seek to obtain in Queensland in 2009-10 would not be materially different from what it would seek to obtain in Queensland in 2008-09.

What has changed between the two tariff years is the fact that the BRCI for 2009-10 is being finalised in November 2008 only six months after the BRCI for 2008-09 was finalised in May 2008, i.e. the BRCI for 2009-10 is being finalised six months earlier than the date at which it would have been expected to be finalised (i.e. in May 2009) had the timetable for calculation of the BRCI not changed. This change means that the calculations have to be finalised earlier. As highlighted in section 2.12 above and discussed throughout this report, the consequence is that more estimated data has to be used rather than actual data. There is therefore more uncertainty in the numbers being used in the BRCI calculations than has been the case in previous years' calculations. A retailer that has its sales prices set based on uncertain cost data would be seeking to uplift those costs by an amount higher than would a retailer that has its sales prices set based on more certain cost data. This higher uplift could be regarded as a "contingency", with the objective overall of achieving the same actual retail margin.

We have discussed with the Authority whether we should be proposing a retail margin based on either:

- There being no actual change in the margin that the retailer active in electricity retailing in Queensland would seek to achieve as between 2008-09 and 2009-10; or
- The earlier calculation of the BRCI resulting in more uncertainty in the BRCI cost inputs and therefore a higher retail margin may be warranted in the BRCI calculation, in order to try to achieve the same retail margin in the two years in the actual outturn.

The Authority has informed us that it would interpret the legislation regarding a reasonable retail margin for the retailer as being the margin that the retailer would seek to achieve and thus unchanged, and would not see the change in timetable for the BRCI calculation as reason in its own right for increasing the expected outturn retail margin. On that basis, the retail margin of 5% used in 2008-09 remains the proposed retail margin for the BRCI calculations for 2009-10.

5. NETWORK COSTS AND OTHER RELEVANT COSTS

5.1. NETWORK COSTS

The Authority provided us with network costs of $2,338,200,000 for calculation of the BRCI for 2009-10.

5.2. OTHER RELEVANT COSTS

As discussed in section 2.2 above, the Act allows for the calculation of the BRCI to include *any other relevant costs* that the Authority considers to be relevant. Careful consideration has been given to what those costs might be, and the view has been reached that as in other regulatory decisions on retail costs in Australia all the relevant costs should be and have been taken into account as the cost of energy, network costs or retail costs as appropriate, and there are no other relevant costs to be included here.

6. RESULTS

Error! Reference source not found. below shows a summary of the current (draft) results for the calculation of BRCI for 2009-10 as presented in this report.

Table 28: Draft BRCI calculation results

Cost Item	Report section reference	2009-10
Cost of Energy ($/MWh)	3.7	$56.90
NEM Load (L) (MWh)	3.8	36,436,970
Total Cost of Energy ($)		**$2,073,235,714**
Retail Costs ($/customer)	4.2.9	$111.20
Customer Numbers	4.1	1,972,489
Total Retail Costs *excluding retail margin* ($)		**$219,341,171**
Total Network Costs	5.1	**$2,338,200,000**
Other Relevant Costs	5.2	**$0**
Total Benchmark Retail Cost *excluding retail margin* ($)		**$4,630,776,885**
Margin on Revenue (%)	4.3.5	5.00%
Margin on Revenue ($)		**$243,725,099**
Total Benchmark Retail Cost (R) *including retail margin* ($)		**$4,874,501,984**
BRCI for the Year (equals R / L) ($/MWh)		**$133.78**
BRCI for the Year (equals R / L) (¢/kWh)		**13.38**

Source: CRA analysis

Given that the Authority used a value of 12.13¢/kWh as the BRCI for 2008-09, these (draft) BRCI calculations equate to a year-on-year increase from 2008-09 to 2009-10 of 10.27%.

APPENDIX A: OUTLINE OF CONSULTANCY FROM THE TERMS OF REFERENCE

The consultant will be required to assist the Authority to calculate a BRCI for 2009-10, based on the estimated total cost of electricity in 2009-10 and the National Electricity Market (NEM) load for Queensland in 2008. Two reports to the Authority are required as part of this consultancy.

In its first report, the consultant will be required to propose an approach for determining the BRCI subject to the requirements set out in the *Electricity Act 1994*, the *Electricity Regulation 2006* and the 11 March 2008 delegation certificate from the Minister to the Authority.

The Authority established the framework for determining each element of the benchmark retail cost index in its May 2008 Final Decision on the 2008-09 BRCI. It is currently expected that the same framework will be adopted in calculating the BRCI for 2009-10. Given the shortened timeframe for this assessment, it is currently not anticipated that there will be any changes to the method of calculation, and therefore no requirement to recalculate the BRCI for 2008-09. However, the shortened timeframe for this review will require data for some elements of the BRCI, which has in previous years been available as actual data, to be forecast.

The consultant will be expected to respond to issues raised in submissions received by the Authority in response to an interim consultation notice.

In a second report to the Authority, the consultant will be required to update its first report to take account of more recent information and respond to submissions received from interested parties in relation to the Authority's Draft Decision. The consultant will be required to attend and participate in a workshop on or around 27 August 2008 following release of a draft version of its first report.

APPENDIX B: APPROACHES USED TO DETERMINE ALLOWABLE ENERGY COSTS IN OTHER JURISDICTIONS

The approach to calculating the energy component of the prescribed retail tariffs varies between jurisdictions in the NEM. These are summarised below for Victoria, South Australia and NSW:

B.1 VICTORIA

In Victoria, CRA was engaged by the Victorian Government to determine appropriate allowances for costs, including wholesale energy, in retailers' standing tariff offers for the year 2003, and then for the four-year period 2004 to 2007 inclusive. The analysis of energy costs undertaken by CRA aimed to determine the benchmark range that a prudent and efficient retailer should be able to match, given reasonable purchasing decisions and risk policies.[81] It did not use an LRMC-based approach. Instead it involved:

- Determining how much contract volume is purchased and the time periods over which these purchases take place; and
- Applying benchmark prices to cost the purchases using publicly available contract prices.

AFMA data was used in determining the contract prices because it is publicly available, and is based on a survey sample of contract market participants, so, while it has limitations, it can give a good indication of market prices.

Each year was divided into four quarters and a block approach was used to model energy purchases through swap contracts (flat, peak and off-peak) and cap contracts. A benchmark approach was used to estimate swap contract costs using the AFMA data, with the contracts assumed to be purchased over a 24 month period in advance of the year for which the energy is being purchased. Cap prices were calculated using a proxy of an open cycle gas turbine, assuming a range of input costs. Finally an additional allowance was made for residual risks such as contract mismatch and demand variability.

81 *Electricity and Gas Standing Offers and Deemed Contracts (2004 – 2007)*, CRA, December 2003.

B.2 SOUTH AUSTRALIA

In South Australia, the Allen Consulting Group (ACG) was engaged by the Essential Services Commission of South Australia (ESCOSA) to determine the wholesale energy cost that should be built into South Australian electricity retail standing contract prices, for the three and a half year period starting January 2005. The approach taken was to calculate the cost that a prudent and efficient retailer would incur in purchasing energy. ACG assumed that a prudent retailer should seek to purchase energy at the best possible price, while appropriately managing risk by contracting to levels that cover at least expected demand under medium growth assumptions.[82]

ACG developed five scenarios that have different forecasts of demand and pool prices. ACG then sought to identify the optimal contracting strategy for the retailer that minimised the financial impact of the variability in load and prices across the scenarios.[83]

This approach was used in preference to using the LRMC as a basis for determining the allowance for wholesale energy costs. However, the Electricity Supply Industry Planning Council (ESIPC) provided a report to ESCOSA on the LRMC of energy based on a mix of base load and peaking generation to meet the mix of small customer load (i.e. new entrant prices).[84] These new entrant prices were used by ACG as an input to scenarios where pool prices averaged new entrant levels, and in calculating new entrant price premiums for contracts.[85]

ESIPC estimated the LRMC based on the optimal mix of plant to supply the load profile applicable to the small customer segment of the market reliably, assuming it is a standalone market. For each plant type it developed a new entrant cost analysis model, based on a cash flow approach, to evaluate the $/MWh price required by a new entrant generator such that the project is financially viable. It then used an optimising algorithm within a spreadsheet model to determine the optimal mix of base load and peaking/reserve plant such that the LRMC for the load was minimised.

This approach adopted in South Australia differs from the framework for calculating the BRCI. It places a greater emphasis on contract and pool prices for determining the cost of purchasing energy and uses the LRMC only as an input to pool scenarios.

82 *Final Report Energy Wholesale Price Study*, ACG, 13 September 2004, p1.

83 *Inquiry into Retail Electricity Price Path Final Report*, ESCOSA, March 2005, p43.

84 *Estimates of the Long run Marginal Cost of Supplying Electricity to Small Customers in 2005*, ESIPC, 31 August 2004.

85 *Final Report Energy Wholesale Price Study*, ACG, 13 September 2004, p22.

B.3 NEW SOUTH WALES

In NSW, the approach taken in the 2004 determination and 2007 determination is similar to that in Queensland, with the LRMC forming the basis of allowed energy costs. However, the Terms of Reference for the most recent determination stipulates that the approach should, in addition, take into account hedging costs, risk management and transaction costs.[86] A summary of the approaches taken in 2004 and 2007 is provided below.

B.3.1 NSW 2004 Price Determination

For the 2004 Price Determination, IES was appointed to provide advice on the LRMC of energy. Its approach was to determine the LRMC such that each generation development program is based solely on meeting the load profile with the lowest cost combination of new entry generation.[87] This approach is consistent with the approach prescribed for Queensland in Section 92 of the Act.

IES considered three technologies in determining the optimal mix of generation that would meet the energy demand in NSW at lowest cost. These were black coal thermal power stations, combined cycle gas turbines and open cycle gas turbines. For each technology, IES presented three estimates of capital cost and variable operating cost (fuel plus variable operating and maintenance costs). These estimates were modelled as scenarios that represented a high, medium and low range of estimates for each capital and operating cost for each plant type. In calculating the LRMC for each retailer, IES considered each retailer's energy demand independently and did not undertake detailed modelling of the NEM.

Based on the cost of the three technologies and the load of each retailer, IES used a Linear Programming (LP) model to calculate a high, medium and low estimate of the LRMC for each retailer in NSW. IES approximated the Load Duration Curve for each retailer by using 438 data points instead of the 17,520 half-hourly load points available; this was done due to operating constraints of the LP model that IES was using. The LP program was formulated to minimise the total of annual variable costs and annualised capital costs. The mix of plant was selected by the LP program such that the shadow prices produced in each time period, which represent the marginal cost of supply in that time period or load duration segment, provide no producer surplus or deficit.[88]

---

86 *Promoting Retail Competition and Investment in the NSW Electricity Industry – Regulated Electricity Retail Tariffs and Charges for Small Customers 2007 to 2010*, Final Report and Determination, IPART, June 2007, section 6.

87 *The Long Run Marginal Cost of Electricity Generation in New South Wales,* Report to IPART, IES, February 2004, p2-6.

88 *The Long Run Marginal Cost of Electricity Generation in New South Wales,* Report to IPART, IES, February 2004, p2-13.

Under IPART's Terms of Reference, IES was also required to consider the cost of green energy schemes such as the MRET scheme and the NSW Greenhouse Gas Abatement scheme. However, IES excluded these green energy schemes from its calculation of the LRMC on the basis that the schemes "*have fixed targets and therefore on a marginal cost basis their costs to the aggregate NSW energy demand cancel out in the calculation of marginal cost*".[89]

B.3.2 NSW 2007 Price Determination

For the 2007 Price Determination, Frontier Economics was appointed as the consultant to determine energy costs. The approach, as determined by IPART's Terms of Reference, required the LRMC of electricity generation from a portfolio of new entrant generation to supply the load profile of customers remaining on regulated tariffs to form the basis of allowed energy costs.

Frontier Economics adopted a similar approach to that used by IES in the previous determination, although there are key differences that are summarised below. Frontier Economics computed the least-cost mix of generation and greenhouse abatement investments to meet the retailer's load for customers on regulated tariffs, subject to meeting a system reliability target (as determined by NEMMCO) and any greenhouse emission targets.

The approach of Frontier Economics differs from that undertaken by IES in the following ways:

- The Frontier Economics approach optimises (minimises) the total fixed and variable costs of meeting demand for electricity in the NEM, taking into account interconnection between regions. This produces a series of prices in each period modelled, which are multiplied by the regulated load of the retailer in the corresponding period to determine the LRMC of providing energy for that retailer's regulated load. In contrast, the IES approach considers the retailer's load in isolation and computes the LRMC of meeting only this load without considering the total load in NSW or interconnection between regions.

- The Frontier Economics model explicitly calculates the cost of meeting the various green energy targets The cost of purchasing NGACs are estimated on the basis of incremental costs, that is, having regard to the existing system. This approach takes account of the emission rates of the current stock of plant rather than for a new entrant plant mix that would have lower emissions. The costs of meeting the MRET target have been estimated on the same basis. In contrast, the IES approach did not explicitly model the green energy schemes.

89 *The Long Run Marginal Cost of Electricity Generation in New South Wales,* Report to IPART, IES, February 2004, p2-12.

- Frontier Economics models the cost of providing the required level of reserve capacity as determined by NEMMCO. The reserve capacity requirement for a region is generally set to the size of the largest generating unit or interconnector transmission line capacity in the respective region. In NSW, NEMMCO currently requires there to be 660 MW of reserve above the 10% Probability of Exceedance (POE) Maximum Demand. This amount remains fixed as load grows into the future. In contrast, IES concluded that "*on a marginal cost basis, given that the required reserve level remains fixed at 660 MW as load increases, reserve costs cancel out in the calculation of marginal cost*".[90]

90 *The Long Run Marginal Cost of Electricity Generation in New South Wales,* Report to IPART, IES, February 2004, p2-11.

APPENDIX C: ALTERNATIVE APPROACH TO ESTIMATING THE QUEENSLAND LOAD FOR 2008 FOR CALCULATION OF THE LRMC

C.1 OVERVIEW

The methodology as specified in Regulation requires that the calculation of the LRMC is based on load data for the preceding calendar year. It is not possible to use 12 months of actual data for the 2009 calculation, as the calculation must be performed before the end of the 2008 calendar year. It is therefore necessary to develop a forecast of the load duration curve for the remainder of 2008.

We note first that load forecasts can be time-ordered (i.e. detailed half-hourly forecasts) or they can be time independent (i.e. a pure load duration curve). We have used CRA's PEPPY model to calculate the LRMC. PEPPY requires time-ordered data, and therefore the techniques that produce time-independent forecasts cannot be used. For completeness we briefly review time-independent methodologies and then discuss the time-ordered methodologies.

C.2 STATISTICAL APPROACHES

6.1.1. Time independent forecasting methodologies

There is an extensive literature on forecasting load duration curves, but the literature is focussed on forecasting entire year LDCs, rather than part year LDCs. The literature is also focussed on the requirements for system planning, which typically revolve around how much capacity is required to ensure that there are no supply shortages in all but the most extreme circumstances, and sometimes also on estimating the benefits from DSM given an assumed reduction in peak demand. Because of the focus on utility planning requirements, the literature also considers the development of an "equivalent load duration curve", which convolves the expected load duration curve with possible outages from generation plant.

LDCs in the literature may be estimated as a polynomial function, or other functional form that replicates the shape of the LDC. Generally no attempt is made to explain the shape of the LDC in terms of underlying demand drivers.

Commonly the literature does not explain the peak of the LDC or the absolute level of energy consumption – those being treated as separate tasks.

At a practical level, the New Zealand Electricity Commission has randomly generated a range of possible LDCs given a base load shape together with random variations in peak, energy, and "peakiness" of load. After running a large number of scenarios a load probability curve is estimated for each future year (the load probability curve looks similar to an LDC, but it is calculated from a large number of LDC simulations). Essentially this is a representation of a more general approach that develops forecasts of a large number of conditional load duration curves (with each curve conditional upon peak and/or peakiness and/or energy), and then calculating the average of the conditional curves. While apparently sophisticated in nature, this approach still requires a forecast of peak. This approach also does not answer the question of whether we can forecast the second-half-year LDC from that observed in the first half of the year.

There is no single off-the-shelf technique that can quickly and easily be applied to forecasting a second-half-year LDC from the first half year. At a minimum we would need to be able to take historical data for the first half year and the second half year, and try and determine statistically whether there is a relationship between the two. Because there are so few years of data available it would be necessary to characterise each half year with the minimum possible data. One option would be to use the three parameters used by the New Zealand Electricity Commission to characterise LDCs:

- Peak
- Energy
- "Peakiness", which can be calculated as (Max – P1)/(Max – Mean) where P1 is the 1st percentile.

Regressions could then be run comparing the LDC for the second half of each year with the first half of the year. More complex models could also include explanatory variables such as maximum temperature, or the product of (a) the number of days that the temperature was above a threshold and (b) the average amount by which the temperate exceeded the threshold. One difficulty with this approach is that we do not have a theoretical underpinning for the relationship between the first half of the year and the second half, so we must make intuitive assumptions, and then guess at how that might translate into a functional form. This is not insurmountable, it just makes the task more difficult. The more difficult problem is that we have so few observations – just 9. This significantly limits the ability to apply any advanced statistical techniques (or even any complex functional forms), and limits the number of additional explanatory variables that could be used in the model.

Finally, all of these time-independent techniques are focussed solely on modelling the shape of the LDC. None of them provide chronological half-hourly data, and all require a peak forecast. Even if we could use time-independent data, it would be necessary to develop an estimate of the peak for the second half of the year that was somehow related to the peak (or other aspects of the LDC) for the first half of the year.

6.1.2. Time-ordered forecasting methodologies

Time ordered forecasting methodologies provide detailed half hourly forecasts of data. There are three main techniques that could be applied to developing the data required for the second half of 2008:

- At the simplest level, we could just take the most recent 12 months of data, which covers the second half of 2007 and the first half of 2008. The data from the second half of 2007 would then be "grown" to meet a projected peak and energy level for the second half of 2008. This approach assumes that the shape of load in the second half of 2007 is a good predictor of the shape of load in the second half of 2008.

- A modification of the above approach is to identify a year that appears to be a reasonable representation of what we would expect in the second half of 2008. If we have no particular expectations of weather or other demand drivers, then this would suggest using a year where the LDC for the second half of the year was a close approximation to the average across recent years. The data from the selected year would then be "grown" to meet a projected peak and energy level for the second half of 2008.

- More advanced time series techniques and forecasting methods such as the use of Kalman filters could be used. This would generate a forecast of half hourly data, and it would use the actual data from the first half of 2008 as a starting point. This would seem to be an ideal solution as it firmly links the forecast for the second half of the year to the actual data for the first half of the year. However, the procedure is far from transparent, and may be difficult to replicate. This technique will require estimates of seasonal, weekly, and daily periodicity in the data, as well as underlying causal variables such as temperature and economic growth. It is also not obvious that the "filter" techniques are particularly necessary here (they are designed for dynamic control problems), as statistical models with autoregressive components will also adapt over time and produce forecasts from current observations.

C.2.1 Advanced statistical techniques

A potential problem with the advanced half-hourly forecasting models is that there is no guarantee of the resulting shape of the load duration curve. The model might have a reasonable fit to observed data, but it may fall short when predicting the all important top end of the curve. Indeed, the very use of statistical techniques will smooth out the "noise" that is responsible for generating a number of the peaks (and here it is relevant to note that a Kalman filter is designed to determine the "true" state of the underlying variable given noisy observations. So a particularly high peak would be treated as noise and not necessarily be included in forecasts). The only way to ensure that these peaks are included in the forecast data is, in each predicted half hour, to randomly select a value from the error distribution that is generated by the statistical model. The resulting forecast would be one possible forecast. Ideally it would then be necessary to generate additional randomised forecasts, and then develop a prediction from those forecasts. In our view this makes the forecasting problem needlessly complicated, with no guarantee that the forecasts will be "better" than those more directly derived from observed data.

The weather problem

We assume that the weather is a major determinant of the shape of the load duration curve, both across an entire year, and for seasons within the year.

As for a whole-year LDC, the LDC for a particular part of a year may be "normal", more peaky than normal, or less peaky than normal. Unless we have particular reasons to believe that the second half of 2008 is likely to be more or less peaky than normal, then it would be reasonable to use some approximation to the "normal" shape of the LDC.

The first half of the year covers summer and autumn. The second half of the year covers winter and spring, and may include some summer peaks if December is relatively warm. It is not obvious to us that the weather in the second half of the year has any necessary correlation with weather in the first half of the year, or that a peaky first half of the year necessarily implies anything about the load shape in the second half of the year. For example, a year that is warmer than average may imply a hot summer (peaky) but warm winter (not peaky). A year that is cooler than average may imply a cool summer (not peaky) and a cold winter (peaky). Or there could be various combinations thereof.

If we cannot predict the weather in the second half of the year, and hence cannot predict the "peakiness" of the LDC for the second half of the year, then it would seem reasonable to use an LDC for the second half of the year that reflects average conditions.

One option for obtaining an average LDC is to weather-correct the underlying half-hourly data for each year and average the resulting LDCs. Weather correction would involve developing regression models to estimate the quantum of load in relevant half hours that was due to either heating or cooling, and then subtracting that estimate from the actual recorded load. This option is possible, and we note that some DNSPs do develop weather corrected data. However, for this methodology to be applied in the current context, it would be necessary to perform this analysis for each jurisdiction in the NEM, and possibly even at sub-jurisdictional level where there are distinct regions within a jurisdiction. For each geographical area analysed it would be necessary to consider the appropriate trigger point for cooling and for heating. While feasible, this is a major exercise which would require detailed consultation on the weather correction methodology before it was possible to begin to develop a representative LDC for use in the generation cost analysis.

C.3 AN ALTERNATIVE APPROACH

An alternative option is to average the LDCs observed across a range of weather conditions, with the additional option of removing known extreme weather years. The "average" could be in the form of a true average where the cumulative probability of each given load level is averaged across scenarios, or it may take the form of a representative year – i.e., a year that provides a close match to what would appear to be the average LDC. Which of these two alternatives is most suitable depends on the purpose for which the LDC is to be used.

- If the requirement is simply for a load shape then calculating an average of load shapes would be appropriate. This would then provide a shape that can be applied to a specified peak and energy level. Given two source LDCs, the average LDC calculated using this methodology will always lie exactly in the middle of the two source LDCs.

- However, if time-ordered data is required, then it is better to select a representative year and then adjust the underlying data to match the required peak and energy levels. If detailed half hourly data was averaged across years then the result is will be an LDC that may have significantly different characteristics to the source LDCs. Selecting a representative year enables the individual half hourly data to be scaled as appropriate.

We are essentially faced with two options:

- Using half hourly data from the second half of 2007 and "growing" that to match projected peak and energy for the second half of 2008 (which is essentially the approach used in the body of this report); or

- Using a representative second half year and "growing" that to match projected peak and energy for the second half of 2008.

Our discussion of weather-related issues suggests that the use of a representative year may be superior to mechanistically using the second half of 2007. However, we note that the Regulation does not allow for weather correction when it is possible to use a full calendar year of data. It is difficult to see why weather correction should be applied when developing a forecast, but not when using actual data (which is in itself being used as a forecast of load shape and half hourly load data from year-to-year). Thus, while applying some form of weather correction may be theoretically superior, our view is that using half hourly data from the second half of 2007 (i.e. the most recent 12 months of data) is more consistent with the Regulation.

C.3.1 Description of the alternative approach

An alternative approach to load forecasting is as follows:

- The load shape for the second half of the year is calculated using each data point as a percentage of a reference peak from the first half of the year;
- For each level of cumulative half hours on the LDC an average of the 'reference peak %' is calculated across the relevant years;
- The reference peak is chosen to minimise the sum of squared errors when comparing each year against the average;
- The reference peak is unique to each jurisdiction and is set to have a maximum of 1000. The reference peaks are NSW 98, QLD 1000, SA 95, TAS 61, VIC 1000;
- There is a distinct shift in the QLD load shape over time, so the sample is split into 1999-2003 and 2004-2007. The average and squared errors for QLD are calculated over the 2004-2007 period;
- For each jurisdiction the average load shape for the second half of the year is used as the load shape for the second half of 2008; and
- For each jurisdiction the actual load shape for the first half of 2008 is combined with the average for the second half of the year to obtain a prediction for the full year.[91]

C.3.2 Results

A general result is that the first half of 2008 has been peakier than average (except for NSW), and this translates into a predicted load shape for the full year 2008 that is peakier than average. This is particularly pronounced for Victoria, where the first half of 2008 has been the peakiest on record, leading to a predicted load shape that is significantly peakier than any recorded load shape over the period 1999-2007.

91 The phrase "first half of the year" is used as shorthand for the period 1 January to 16 July of the year, which is the period for which actual data is available in 2008.

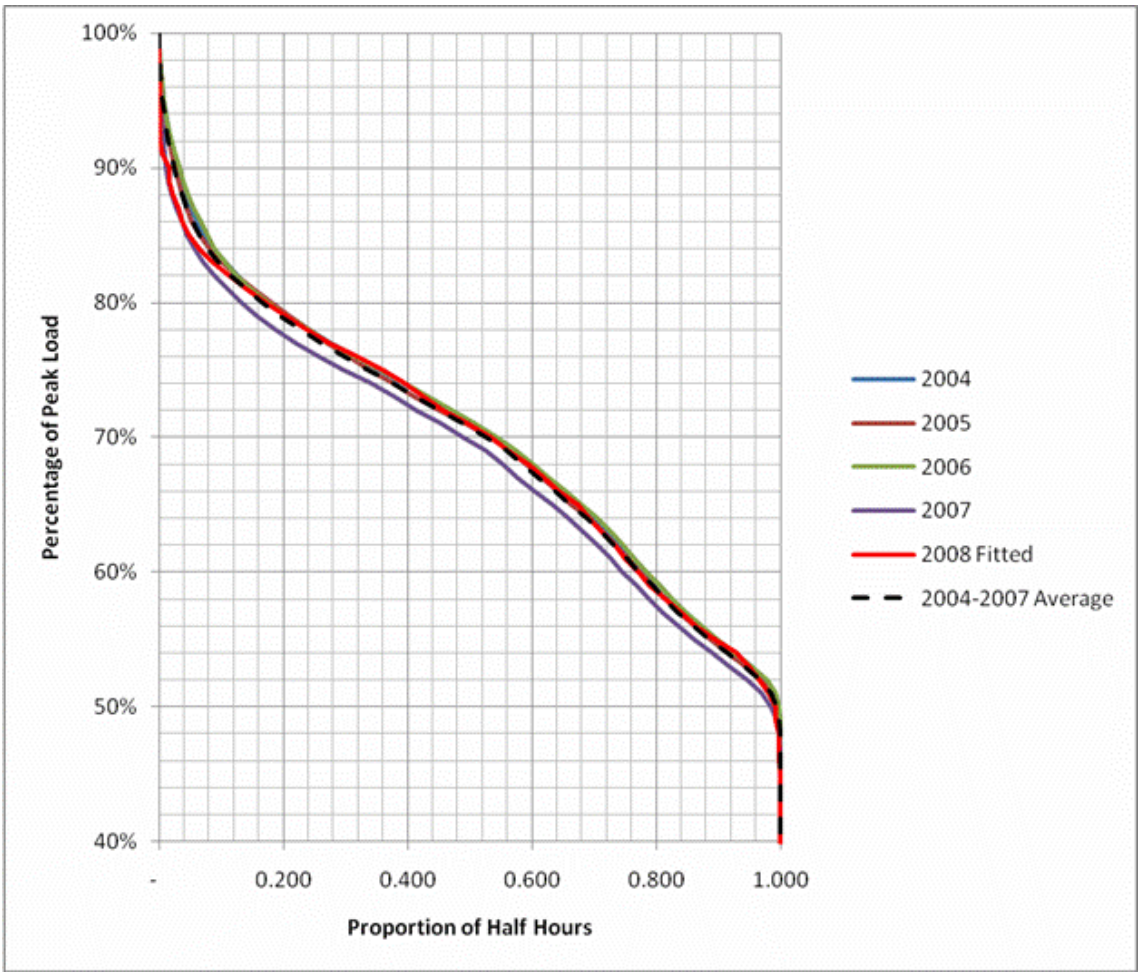
Detailed results by jurisdiction are provided below.

Queensland

The predicted load shape for Queensland for 2008 is very similar to the average over the period 2004-2007:

- The actual peak for the first half of the year is 8,082 MW.
- The historical average relationship between the second half of the year and the 1,000th peak in the first half of the year suggests peaks of 8,281, 8,247, 8,227, 8,207, 8,188, 8,167, 8,146, 8,125, and 8,103 in the second half of the year. This confirms the suggestion that the first half of the year has been exceptionally flat. All else being equal, if the second half of the year is "average" then QLD will incur 9 of its top 10 peaks in the second half of this year.
- Plotting 2004-2007, the average, and the full year 2008 (actual + predicted) indicates that: (a) 2005 is very close to the average, so may be a good choice if half hourly data is required; (b) the top 4% of the 2008 LDC is as peaky as 2007 but then flattens out to become very close to the average.
- The approximate average load factors are 2004 71.2%, 2005 70.8%, 2006 71.2%, 2007 69.7%, 2004-2007 average 70.7%, 2008 fitted 70.9%. (For 1999-2003 the load factors are 76%-78%).

Figure 13: Queensland Load Shape



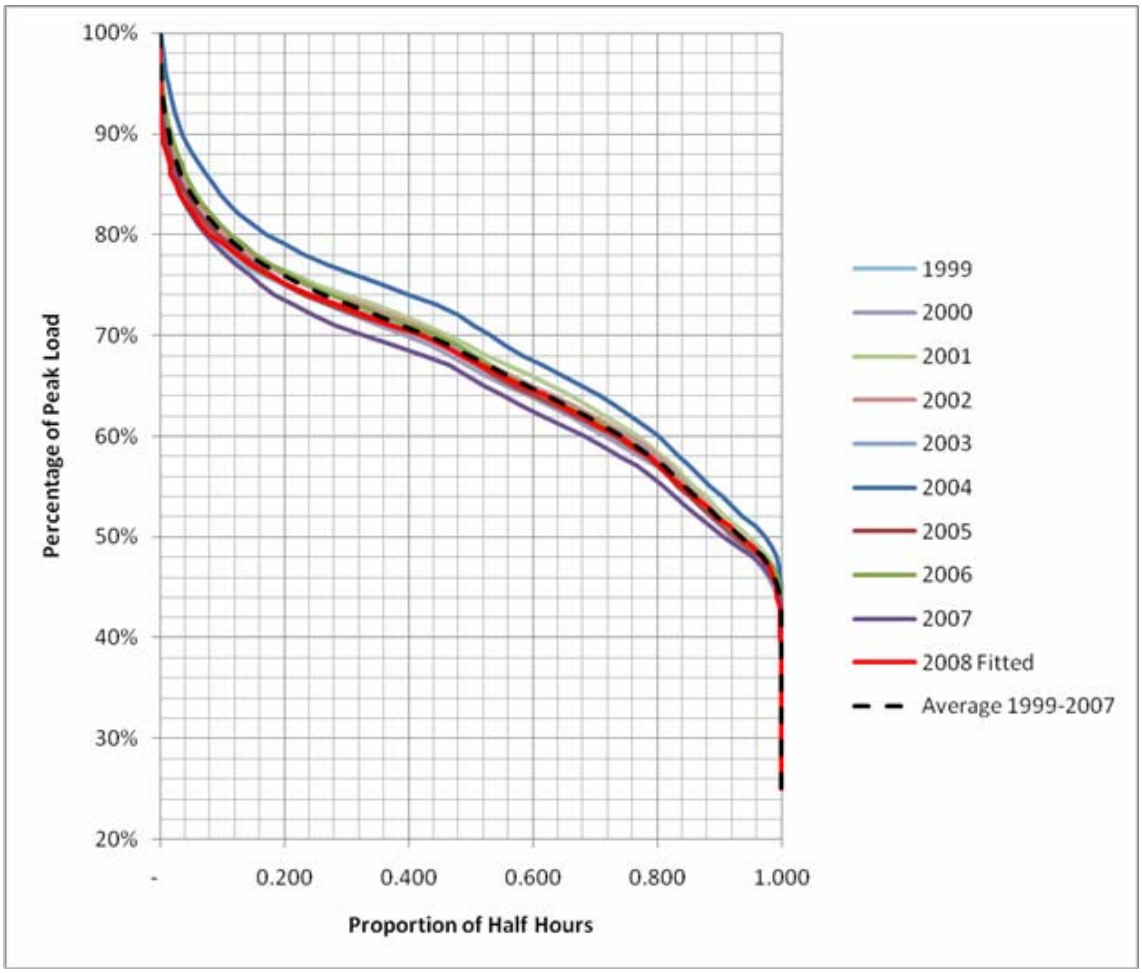
The predicted load shape is close to the average and therefore would seem to be in line with what we would expect. However, it is unusual in that the nine highest peaks occur in the second half of the year. If there is no reason to believe that the second half of the year is necessarily predicted by the first half (e.g. weather), then this result may be reasonable.

New South Wales

The predicted load shape for New South Wales for 2008 is very close to the average load shape:

- The predicted peak for 2008 is 13,162 MW down from the 13,189 MW in 2006 and 13,737 MW in 2007. The highest two peaks for 2008 occur in the actual data from the first half of the year.
- The average load factor for 2008 is approximately 67.6%, compared to 65.8% in 2007 and 67.9% for the average 1999-2007.

Figure 14: New South Wales Load Shape

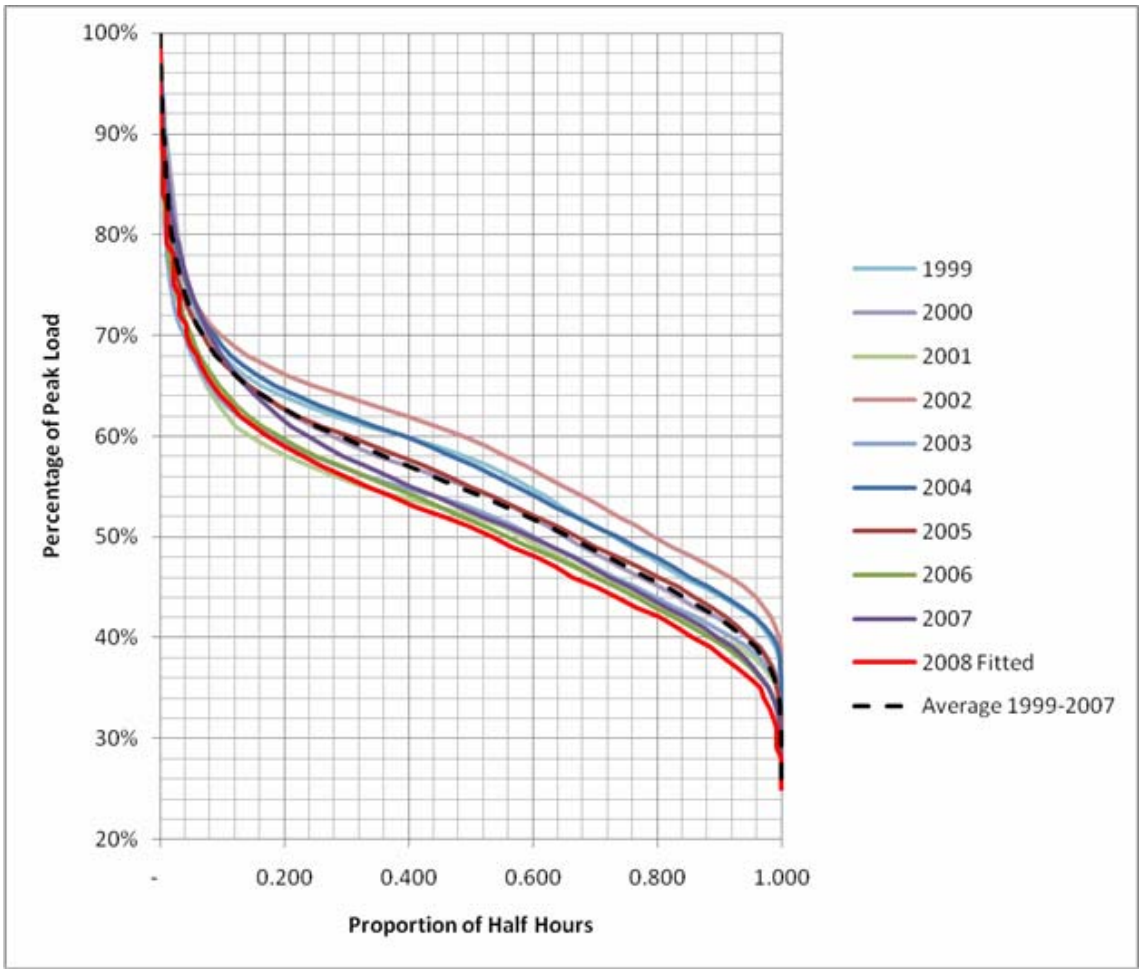


South Australia

The predicted load shape for South Australia for 2008 is a lot peakier than the average:

- The 2008 peak of 3,080 MW is set in the first half of the year, and only 2 of the top 10 peaks are from the forecast data. The peak of 3,080 MW is a significant increase from the 2006 peak of 2,873 MW and the 2007 peak of 2,854 MW.
- The reference peak (the 95th peak) for 2008 is 88.3% of the annual peak. For the average annual load shape, the reference peak is 90.5% of the annual peak. The first half of 2008 has therefore been a lot peakier than average, and this translates into a full-year load shape that is also a lot peakier than average.
- The average load factor for the predicted shape is only 50.9%, compared to the average across 1999-2007 of 54.4%, and the average load factor for 2007 of 52.5%.

Figure 15: South Australia Load Shape



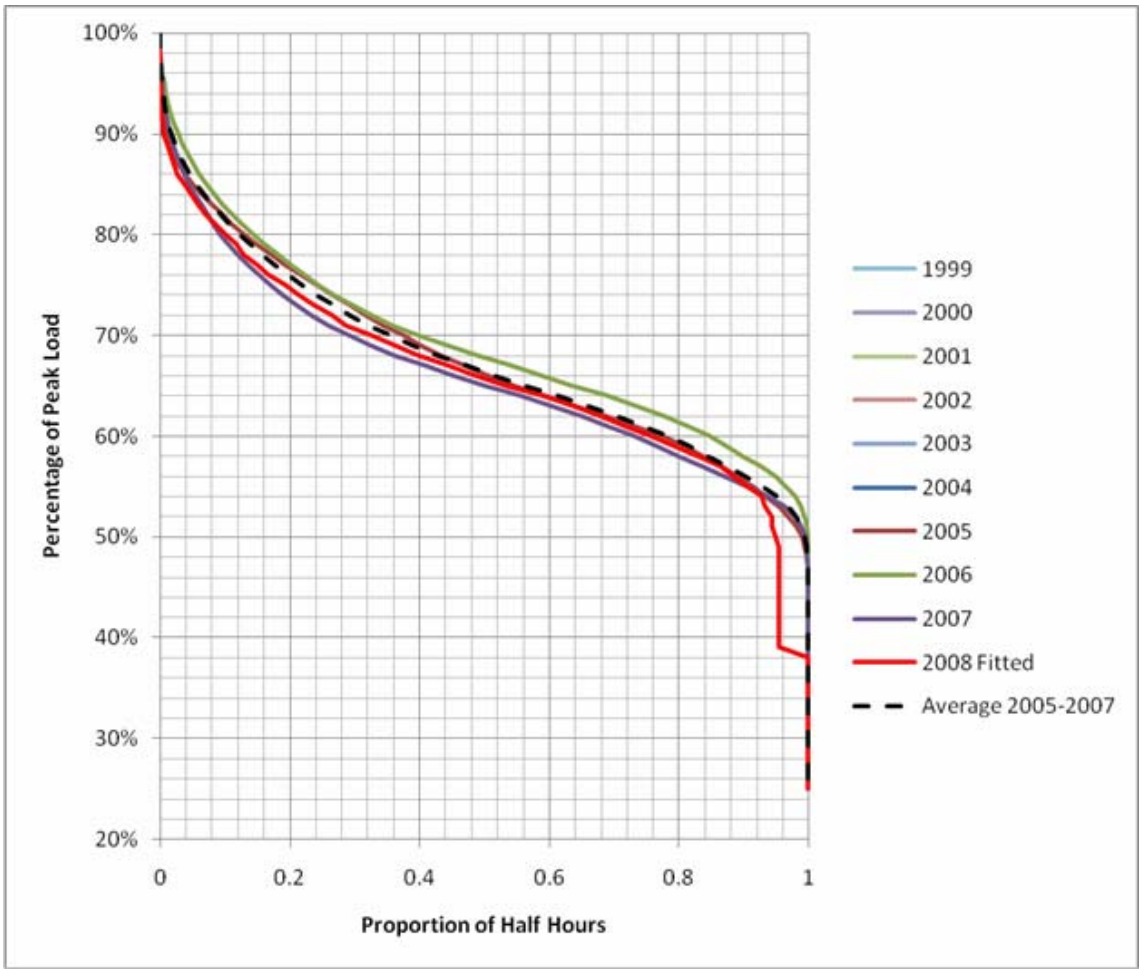
Tasmania

The predicted load shape for Tasmania for 2008 is close to the average load shape:

- The peak for the year is 1,727 MW, down from the peak of 1,753 MW recorded in 2007. This peak is recorded in the first half of 2008, as are eight of the top 10 peaks.
- The predicted load shape is slightly peakier than average. The reference peak (the 61st peak) for 2008 is 92.4% of the annual peak. For the average annual load shape, the reference peak is 95.1% of the annual peak. The first half of 2008 has therefore been a lot peakier than average, and this translates into a peakier predicted full-year load shape for 2008.
- The average load factor is approximately 65.7% for 2008, compared to an average of 66.3% across 2005-2007.

Note: There is a strange anomaly at the bottom end of the predicted load shape for 2008, but this does not affect the top end of the curve or the average load factor.

Figure 16: Tasmania Load Shape

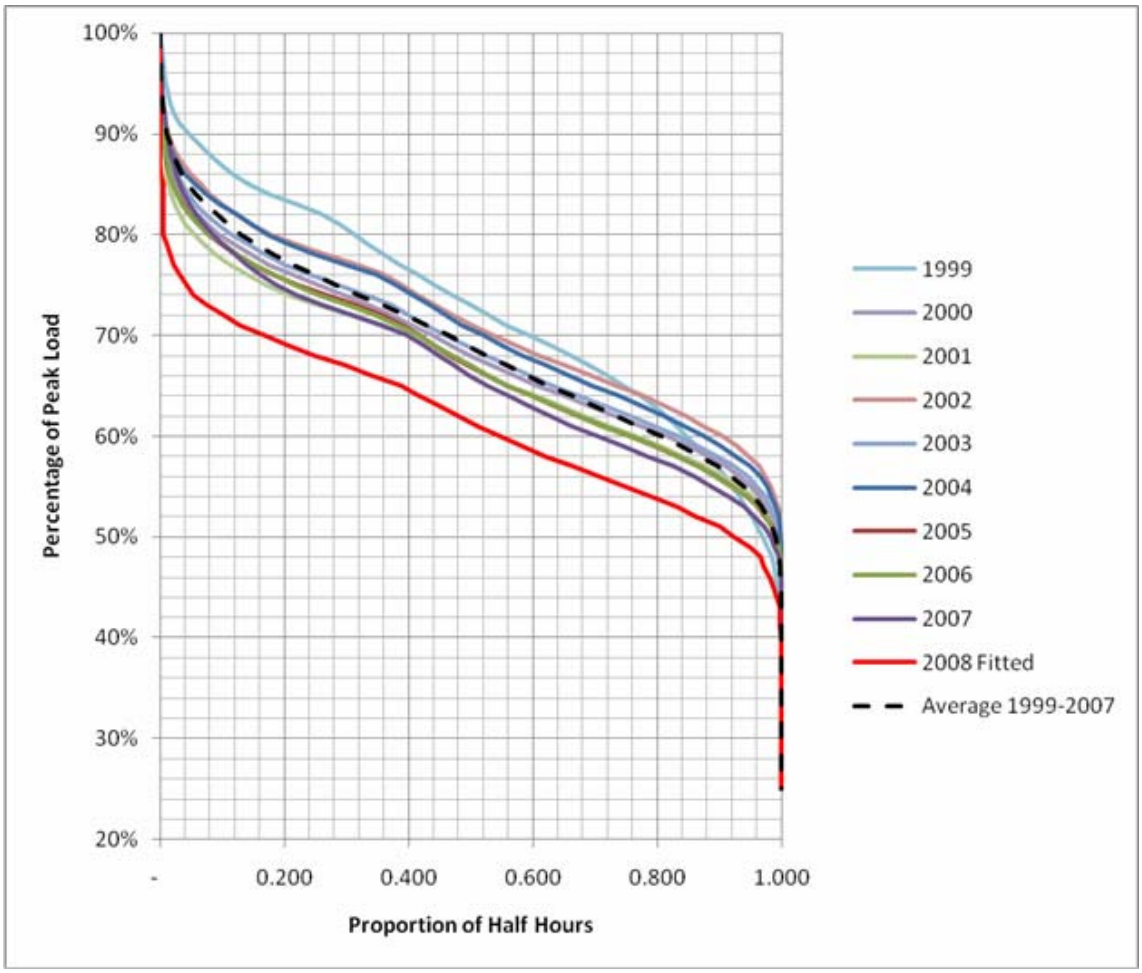


Victoria

The predicted load shape for Victoria for 2008 is a lot peakier than average, and is also a lot peakier than any of the recorded years:

- The annual peak for 2008 is 9,701 MW which is an actual peak recorded in the first half of 2008. The top 10 peaks are all actual peaks from the first half of 2008.
- The reference peak (1,000th peak) for 2008 is 72.3% of the annual peak. For the average annual load shape the reference peak is 84.1% of the annual peak. Again this confirms that the first half of 2008 has been significantly peakier than the average. The minimum ratio previously recorded was 78.2% in 2001, so the first half of 2008 has been the "peakiest" year over the period 1999-2008. This translates into a load shape for 2008 that is peakier than in any previous year.
- The average load factor for 2008 is approximately 61.4%, compared to an average load factor of 68.8% for the annual average.

Figure 17: Victoria Load Shape



APPENDIX D: CEMOS MODEL

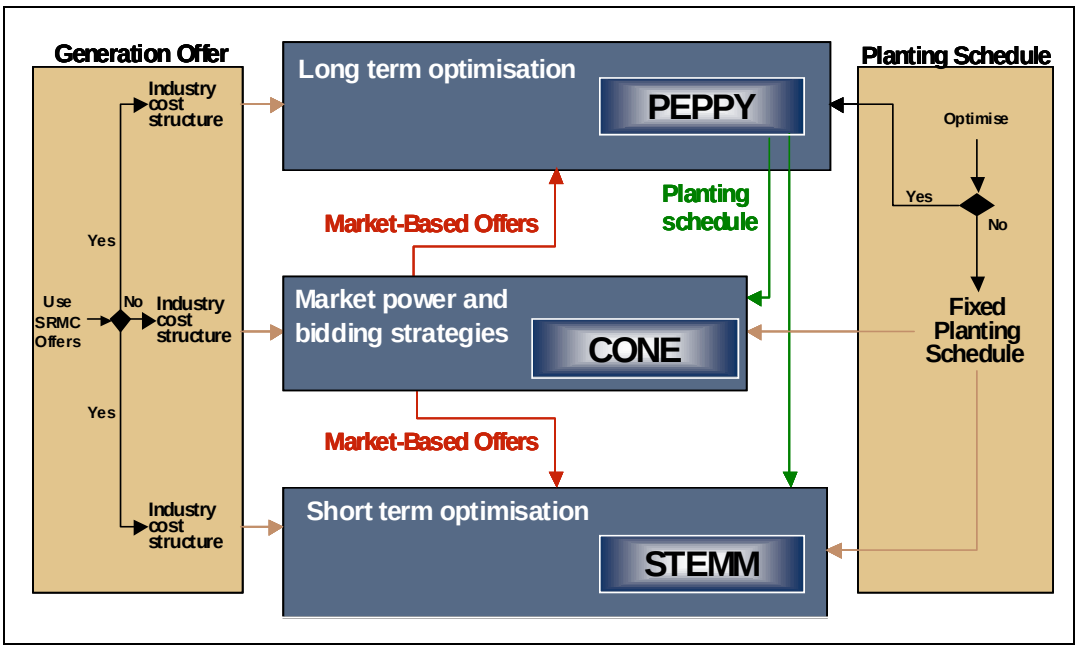
This appendix describes CRA's CEMOS model in more detail:

- Appendix D.1 describes the CEMOS modelling framework;
- Appendix D.2 describes calibration processes for CEMOS; and
- Appendix D.3 describes recent major applications of CEMOS.

D.1 CEMOS MODELLING FRAMEWORK

CEMOS applies state-of-the-art optimisation technology and theory capable of modelling a wide range of electricity market issues. As shown in Figure 18, CEMOS comprises a core set of models with specialist focus on analysing long-term entry/exit dynamics, short-term dispatch / pricing issues and generator bidding strategies.

Figure 18: Interaction of CEMOS components



CEMOS is also supported by a set of bespoke models that are purpose-built to perform specialist analyses, e.g. detailed transmission power flow studies, gas or hydro storage optimisation and simulation, maintenance optimisation, and statistical analysis of historic spot price volatility.

Within the LRMC modelling context, only the PEPPY component of CEMOS is relevant. Modelling of half-hourly pool prices, which is used to calculate the energy purchase costs, is undertaken using the CONE and STEMM components of CEMOS.

D.1.1 Long-term generation capacity expansion and dispatch

PEPPY, the long-term module in CEMOS, optimises electricity market investment and operation, taking into account the physical realities of the electrical power system. It provides a framework for developing insights about the implications of key market drivers over the longer term, such as the type and amount of future generation entry, longer term effects of market power, effects of longer term gas supply constraints, etc. PEPPY uses a linear programming (LP) that models the supply and demand sides together, and the fixed and variable costs associated with both resources. Key features of PEPPY include:

- A detailed consideration of fuel contracts, load growth and its temporal/spatial distribution, and new entrant capex;
- Replication of the market clearing process in the NEM;
- Use of load duration curves;
- Transmission; and
- Ancillary services.

Generation capacity optimisation decisions in PEPPY form an integral part of overall system optimisation and are made in conjunction with generation, transfer, transmission investment and load dispatch decisions. The basic premise for bringing in new capacity is that system marginal costs (or “prices”) should reach a level for the new generator to profitably recover its fixed costs including (annualised) capital investment over all future years of operation. Capacity optimisation therefore recognises:

- Demand growth and distribution of demand over seasons and peak/off-peak periods as captured by the LDC;
- Cost of capital and desired return as captured by the annualised capital cost that needs to be covered through pool revenue;
- Operating/fuel costs or, if used in conjunction with CONE, generator bids that may be higher than fuel costs;
- Demand response as captured by price-responsive or other dispatchable loads or price-responsive customer dispatched loads;
- Deterministic planned and forced outages that effectively put a limit on annual energy production;
- Reserve margin constraints which ensures NEM reliability criterion is met;
- Any additional limitation on energy production such as a fixed capacity profile for wind and geothermal energy and hydro generators; and

- Transmission constraints including contingency constraints and, to a limited extent, spinning reserve requirements in the system.

D.1.2 Generation offer strategy using CONE

CONE is transmission-constrained Cournot model that specifically deals with generation offer creation taking into account value maximising behaviour exhibited by individual gencos.

CONE is a model for analysing market power and competition in an electricity market with few competing firms or companies (characterised as an oligopolistic market in economics parlance). Each company is assumed to maximise its own profit by adjusting the generation supplied to the market while considering the generation supplied from all other competing and non-competing companies and the responsiveness of demand. CONE, therefore, characterises the market as the companies competing solely in terms of generation quantity. This is known as a Cournot game the solution to which comprises generation levels of all firms and the resultant market price is expected to equilibrate. The Cournot-Nash equilibrium solution is found by solving the Cournot game problem, and this yields the generation levels where each company has no incentive to adjust its supply because doing so would reduce its profit. Equilibrium market price is calculated based on the equilibrium generation level.

CONE performs two major functions:

- It calculates the Cournot-Nash equilibrium solution; and
- It creates a set of generation offers based on the equilibrium outcome.

CONE formulates this problem as what is known as a mixed-complementarity problem (MCP) that can also be transformed into an equivalent nonlinear programming (NLP) problem. The MCP/NLP approach simultaneously solves for values of the market price and quantity (or, generation dispatch) variables.

The input data for CONE include:

- Cost: SRMC of each plant;
- Load: an estimate of a demand curve in each period;
- Generation: available generating capacity of each unit in each period; and
- Contracts: contract-for-difference (cfd) quantity.

CONE uses the above inputs to calculate the following outputs:

- Equilibrium quantities of generation for each plant;
- System price; and

- Generation offers that reflect the equilibrium quantity and system price.

An equilibrium solution is found for each period. Typically a multi-year horizon is considered, with each annual load duration curve approximated using non-sequential demand curves representing multiple time periods. CONE is also solved for short-term model for each hourly load condition.

Transmission constraints are modelled in CONE using a DC-approximation of AC power flow constraints. Ancillary services can also be co-optimised in CONE. In other words, CONE is a multi-commodity Cournot model that treats energy and ancillary services as "linked" commodities and gencos trying to maximise value for all commodities.

Last but not the least, CONE is set-up to perform both a perfect competition (PC) mode whereby the social welfare is maximised without considering the dead-weight loss and a Cournot oligopolistic market simulation. The model in fact always performs a PC run to work out the least cost generation target and then develops a contract cover using the PC solution to proceed to perform a Cournot simulation. Indeed the model can be used to perform a standalone perfect competition simulation.

Additional information on the CONE theory is available in the following paper that includes a comparison of outcomes for perfect and imperfect competition regimes:

Chattopadhyay, D., Multi-commodity Spatial Cournot Model for Generator Bidding Strategy" IEEE Transactions on Power Systems, February, 2004.

D.1.3 Short term dispatch analysis using STEMM

STEMM is a short term (daily/weekly) unit commitment and dispatch model. It provides a framework to develop insights about the implications of the engineering characteristics of the gas/oil based existing/new units, shape of daily load curve and short term gaming behaviour/bidding strategies.

STEMM uses a linear program or as an alternative mixed integer program (MIP)[92] approach that optimises the electricity market operation over a few days up to a week taking into account the physical realities of an electrical power system and generator engineering characteristics. The basis of the mixed integer program that achieves this goal rests on the same fundamental tenets as employed for market dispatch engines in many countries including the Australian NEM Dispatch Engine (NEMDE). STEMM has a half-hourly resolution although it can easily be modified to have a higher or lower resolution.

This model seeks to:

> *Achieve the least cost operation of generating units over the planning horizon which may span from a day up to a week, while observing the physical realities and security policies necessary to operate the power system securely.*

The STEMM MIP tries to achieve this fundamental goal by mimicking the market operation in the short term, and is very close in spirit to the actual market dispatch process in real-time.

The key features include:

- Detailed consideration of generating unit start-up/shutdown, ramping for energy/ancillary services;
- Replicating, where possible, the market clearing process of the system;
- Chronological load profile;
- Transmission; and
- Ancillary services.

92 The term mixed integer program (MIP) refers to a mathematical programming problem (typically a linear program) in which (typically a small) part of the decision variables are discrete or integer in nature (i.e. these variables can assume only a few integer values e.g., 0, 100, 200 etc, but nothing in between) while the majority of the variables are continuous. A special case is when all the integer variables are binary i.e., 0 or 1. Most MIPs including the one underlying STEMM falls in this special category and the binary variables represent the ON/OFF status of the generating units. A MIP is generally a lot more computationally intensive than its linear program counterparts. More precisely, the branch and bound algorithm and its variants employed for solving a MIP involves solving potentially thousands or even millions of linear program sub-problems for even MIPs of moderate size having as low as a few hundred integer variables. The Australian version of STEMM does not use the MIP approach and uses instead a simplified linear program approach consistent with the NEMDE formulation.

D.2 CALIBRATION OF CEMOS

In order to produce spot price forecasts, CEMOS relies on parameters such as a very short term elasticity of demand and the contract level of power stations for which no accurate estimate is available. This is because either quality data does not exist as in the case of the elasticity, or the data exists but cannot be obtained easily because it is commercial in confidence, as is the case for generation contracts. Since these parameters have profound impact on modelling outcomes, a pragmatic way to establish a working model is to find out if the model can reproduce reasonable market outcomes within a plausible range of elasticity values that have been reported in the literature, and prevailing views on contract levels in the market.

Calibration then refers to the process by which we explore the impact of alternative levels of elasticity and contract values and compare the outcomes with observed market values. The basic hypothesis is that the market is generally heavily contracted for baseload generation and less so for mid-merit and peaking generators, and that low elasticity is associated with peak period volatility.

Within these broad guiding principles, the calibration process we use involves drawing up an *n*-dimensional grid of the combinations of potential values of the *n* parameters being estimated. Then, for each combination in the grid, a series of Cournot results is produced and assessed against the observed market data including observed generation data as to its goodness of fit. The basic premise is that if the model can reliably and reasonably accurately reproduce the market outcomes, including generation, prices, market share etc. using plausible values of elasticity and contract levels (following the broad principles of how these vary with loading condition and generator types), then the model can be used with confidence to produce outcomes going forward for the same inputs on elasticity and contract values.

The contractual obligations of electricity generators (both in respect of their retailer customers and their fuel supplies) form important assumptions in modelling generator behaviour and profitability. As noted before, power stations that are highly contracted have an incentive to compete more vigorously by submitting bids at their short run marginal cost (SRMC) in electricity wholesale market. Conversely, power stations that have few contracts tend to place more “strategic” bids that are higher than SRMC.

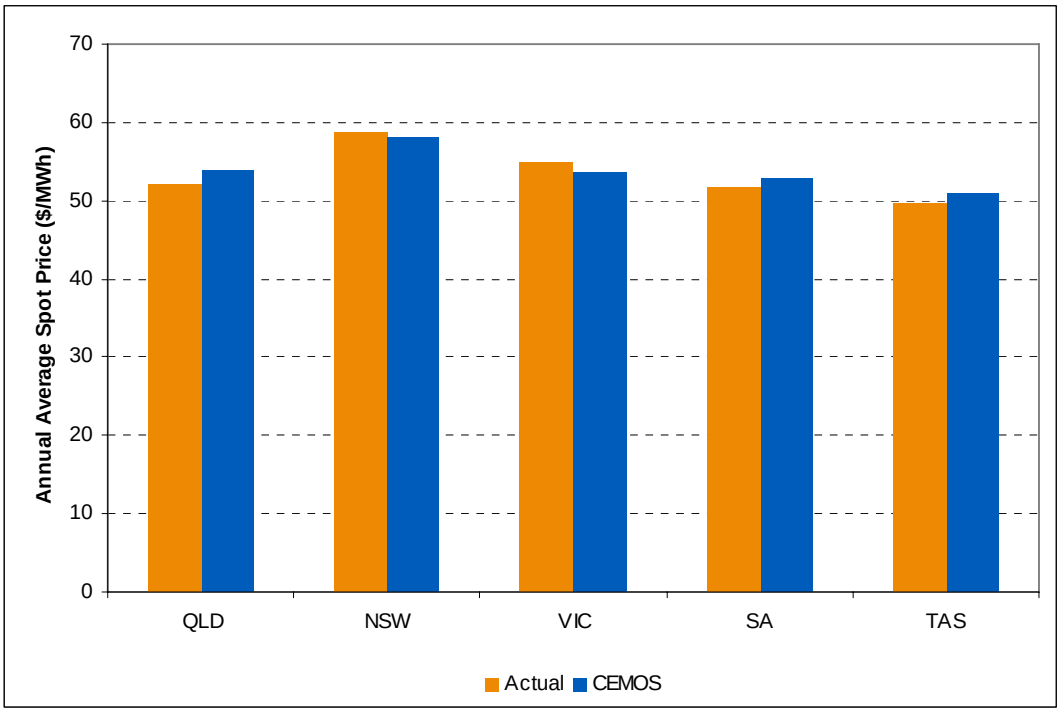
To derive spot prices for 2007 onwards, CEMOS was calibrated based on the combination of (pseudo-) elasticity estimates and assumed (pseudo-) contract coverage (PCL) levels that yield the best fit to the observed price duration curves.[93] Other important indicators assessed were the total GWh generation for the four seasons.

93 These are termed “pseudo-values”, because they are estimated from market data with the implication that market participants behave as if they were playing a Cournot game with these parameters. See J. Tipping, E. G Read, D. Chattopadhyay and D.C. McNickle “Can the shoe be made to fit? – Cournot modelling of Australian electricity prices” *Operations Research Society of New Zealand Proceedings*, 2005. Also, J. Tipping, E.G. Read and D. Chattopadhyay, “Incorporating Bottom-up Structures into Top-Down Models of Electricity Market”, *Proceedings of International Association of Energy Economics, 2007*.

During 2006/07, electricity spot prices in the NEM were exceptionally high. For the purpose of deriving longer term price projections, we have therefore estimated demand function parameters using the average of 2005/06 and 2006/07 spot market prices. The use of this weighted average of the two prices essentially reflects a judgement call that recently observed high price levels in the NEM will not prevail over a longer timeframe in the NEM.

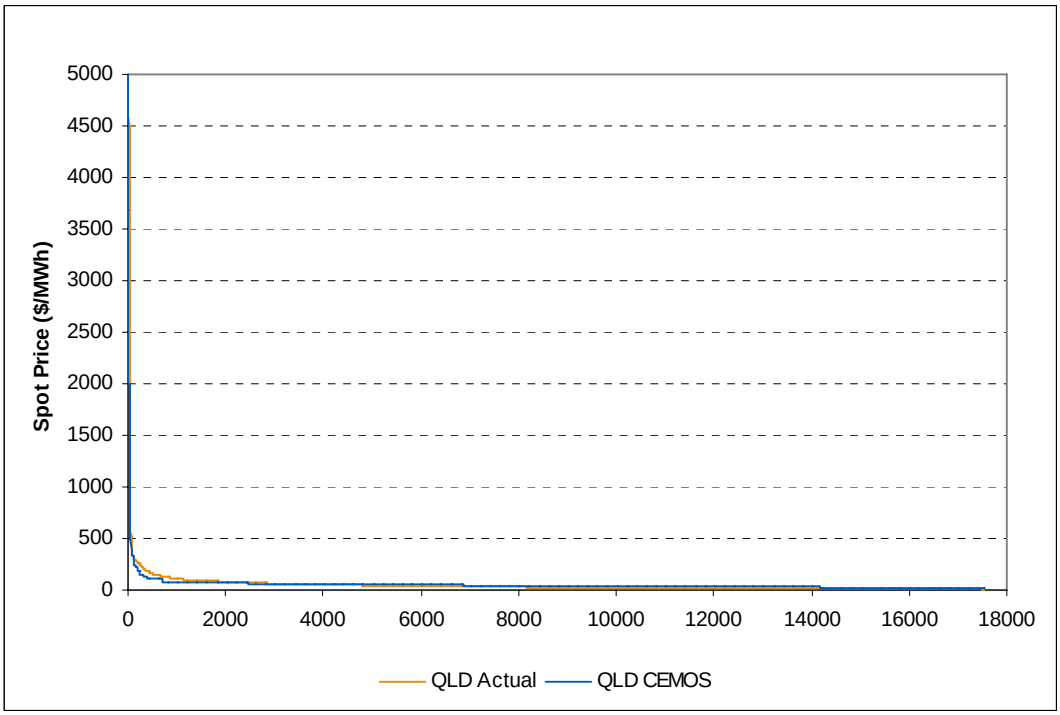
As shown in Figure 19 and Figure 20 below, CEMOS has been calibrated to historical 2006/07 market outcomes. These outcomes can be replicated to a reasonable degree of accuracy, including the distribution of peak/off-peak prices, assuming relatively aggressive bidding strategies. The results of the calibration are shown in Figure 19 and Figure 20, which compare actual prices from 2006/07 with the model results from CEMOS.

Figure 19: Average prices 2006/07 ($/MWh)



Source: NEMMCO actual data and CEMOS modelled data.

Figure 20: CEMOS vs. actual NEM spot price duration curve for Queensland



Source: NEMMCO actual data and CEMOS modelled data.

Notes: The price duration curve describes how frequently (in number of half-hours in the year) certain price outcomes occur.

D.3 RECENT MAJOR APPLICATIONS OF CEMOS

CEMOS has been applied to undertake modelling analyses on a wide range of energy issues in several countries and in different market structures, including Australia, Hong Kong, Korea, Malaysia, New Zealand, Saudi Arabia, Singapore and Thailand. Table 29 provides an overview of recent applications of CEMOS.

Table 29: Selected applications of CEMOS

Country	Applications	Client
Australia	Impact on future investment and profitability of existing generators under a range of carbon constraint scenarios and policy mechanisms	Australian National Generators Forum and the Electricity Supply Association of Australia
Australia	Projections of spot and market outcomes for 2007-2030 to support a bid for the Basslink interconnector, including hydrology and carbon price scenarios	Commercial-in-confidence
Australia	Valuation of demand side response measures (fuel cost savings, reliability improvement and capacity deferral benefits) for 2006-2025	International Energy Agency (IEA)

Country	Applications	Client
Singapore	Fuel competition impact on the Electricity Market of Singapore (NEMS) of the potential introduction of LNG, given existing contract structures and LNG pricing scenarios	Gas Supply Pte
Singapore	Forward pool price projections and modelling of vesting contracts to be implemented for the Singapore Electricity Market	Mirant Singapore
New Zealand	Valuation of economic benefit of 400 kV transmission alternative in the North Island of New Zealand	Transpower New Zealand
South Korea	Development of electricity market arrangements in Korea, including impact of alternative vesting arrangements, pool price projections, market power mitigation, transmission constraints, new entry optimisation	Korea Electric Power Corporation (KEPCO)
Malaysia	Review efficiency of generation dispatch process	Tenaga Nasional Berhard
Saudi Arabia	Valuation of electricity power project investment	Commercial-in-confidence
Malaysia	Model of the integrated Thailand and electricity system to provide forward electricity projections and break-even gas prices for different entry and macroeconomic scenarios	Amerada Hess
South Korea	Valuation and risk assessment for two merchant IPP investments	Commercial-in-confidence

Some of the recent modelling reports where CEMOS has been used are listed below:

- Analysis of the need for additional zones in the Australian market for the Ministerial Council on Energy (www.mce.gov.au/assets/documents/mceinternet/ModellingReport20041123171152.pdf)
- Analysis of transmission investment options in New Zealand conducted for Transpower New Zealand (www.electricitycommission.govt.nz/pdfs/submissions/pdfstransmission/draft-decision/Transpower-vo3-CRAI-transpower-modelling.pdf)
- Evaluation of the impact of alternative greenhouse gas policy scenarios on the electricity sector in Australia for the National Generators Forum (www.ngf.com.au/html//index.php?option=com_remosiitory&Itemid=32&func=fileinfo&id=99)

- Review of reliability standard for the Australian Energy Market Commission (www.aemc.gov.au/pdfs/reviews/Comprehensive%20Reliability%20Review/aemcdocs/003CRR%20Interim%20Report%20-%20Appendix%205.pdf)

- Valuation of demand side resources in Australia for the International Energy Agency (www.demandresponseresources.com/Portals/0/Australia/Australia_CRA%20Report%20on%20Demand%20Response%20Dec%2006.pdf)

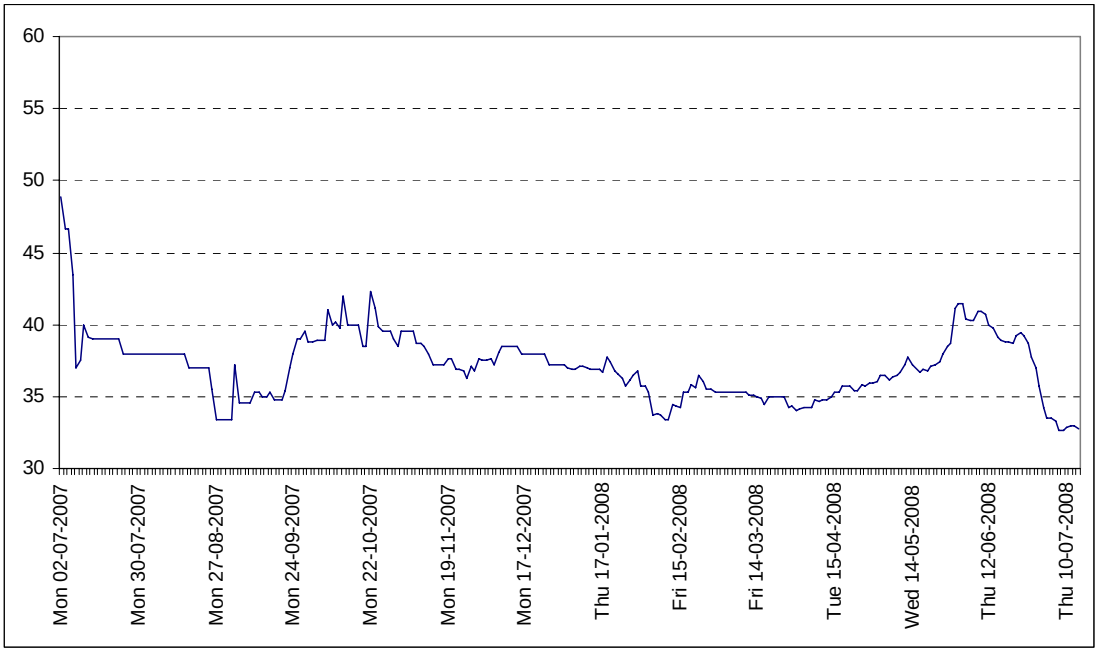
APPENDIX E: GRAPHS OF D-CYPHA TRADE PRICES USED IN ESTIMATING THE COST OF PURCHASING ENERGY IN 2009-10

All the prices in the graphs in this appendix are $/MWh.

E.1 FLAT SWAP CONTRACT PRICES

E.1.1 Q3 2009 – July to September 2009

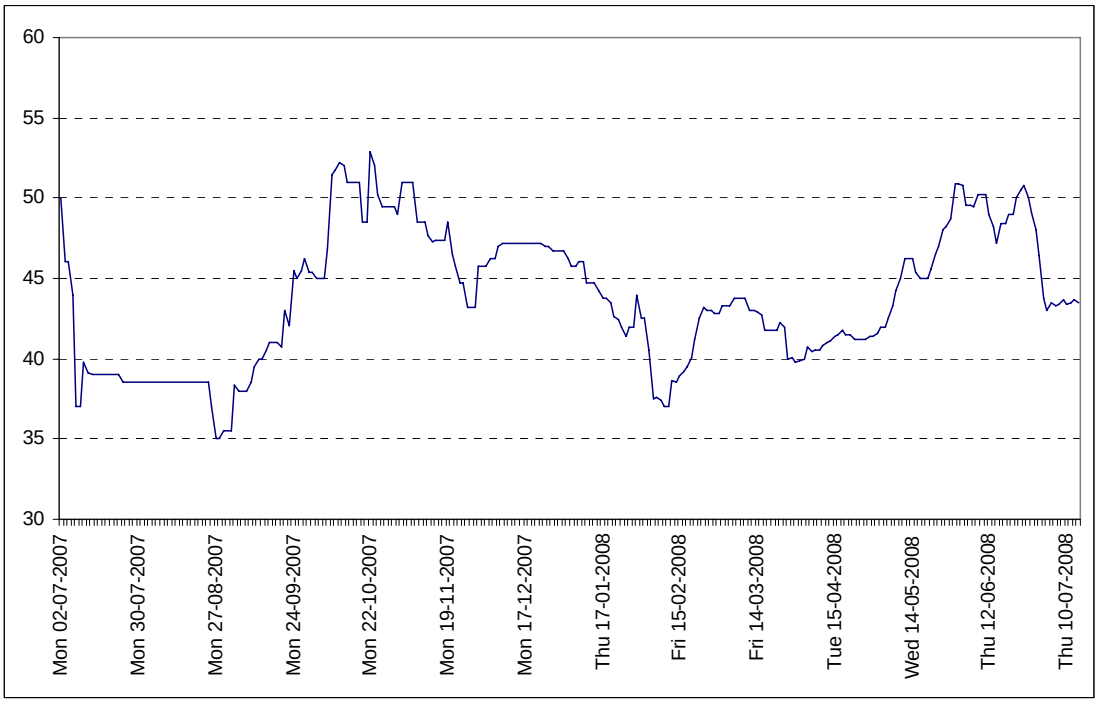
Figure 21: d-cypha Trade prices for Queensland flat swap contracts for Q3 2009 – July to September 2009



Source: d-Cypha Trade data

E.1.2 Q4 2009 – October to December 2009

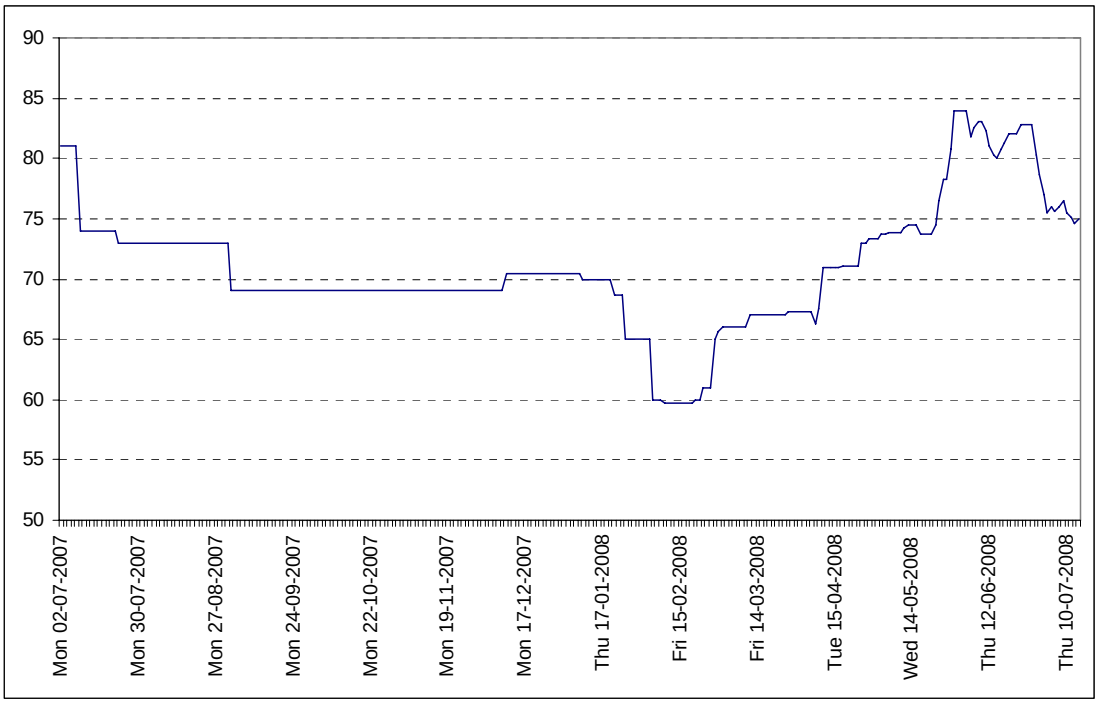
Figure 22: d-cypha Trade prices for Queensland flat swap contracts for Q4 2009 – October to December 2009



Source: d-Cypha Trade data

E.1.3 Q1 2010 – January to March 2010

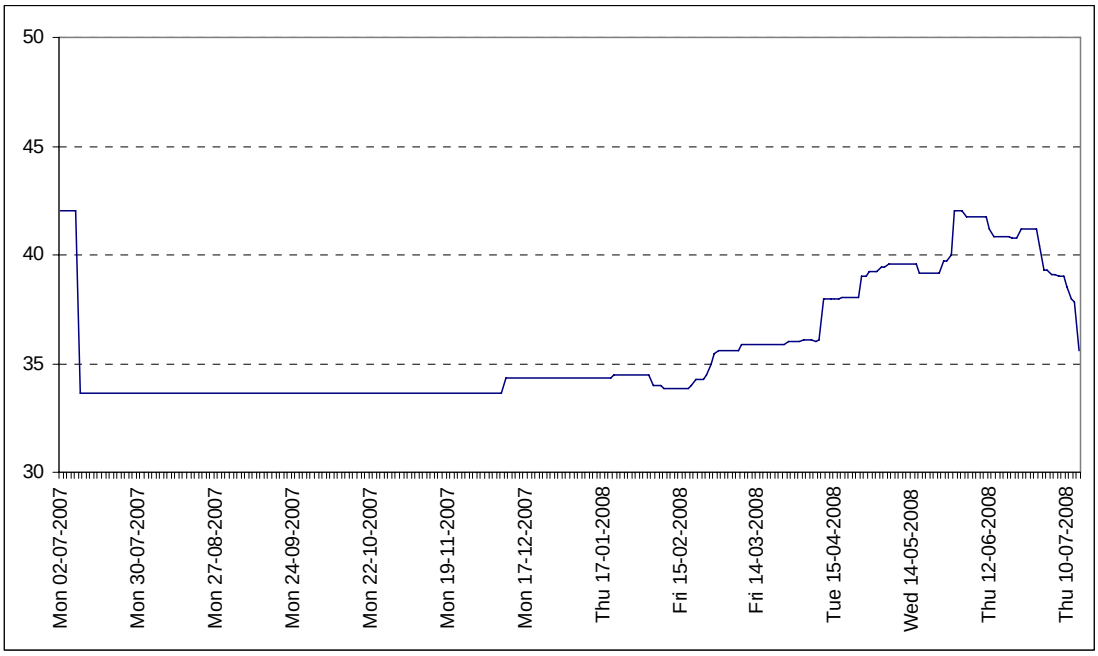
Figure 23: d-cypha Trade prices for Queensland flat swap contracts for Q1 2010 – January to March 2010



Source: d-Cypha Trade data

E.1.4 Q2 2010 – April to June 2010

Figure 24: d-cypha Trade prices for Queensland flat swap contracts for Q2 2010 – April to June 2010

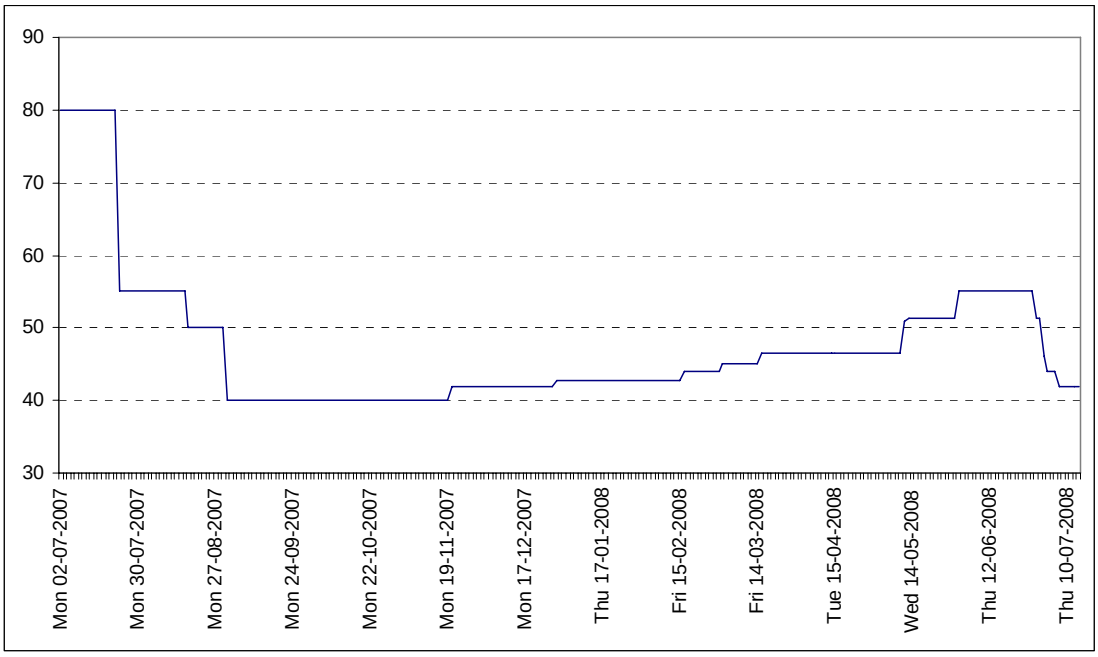


Source: d-Cypha Trade data

E.2 PEAK SWAP CONTRACT PRICES

E.2.1 Q3 2009 – July to September 2009

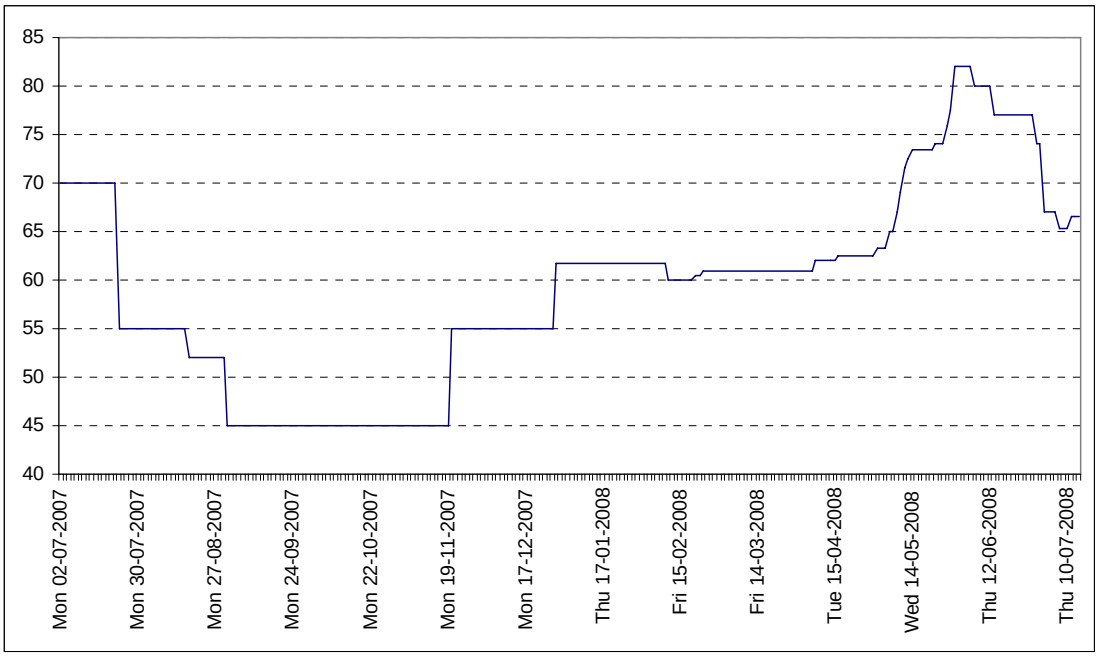
Figure 25: d-cypha Trade prices for Queensland peak swap contracts for Q3 2009 – July to September 2009



Source: d-Cypha Trade data

E.2.2 Q4 2009 – October to December 2009

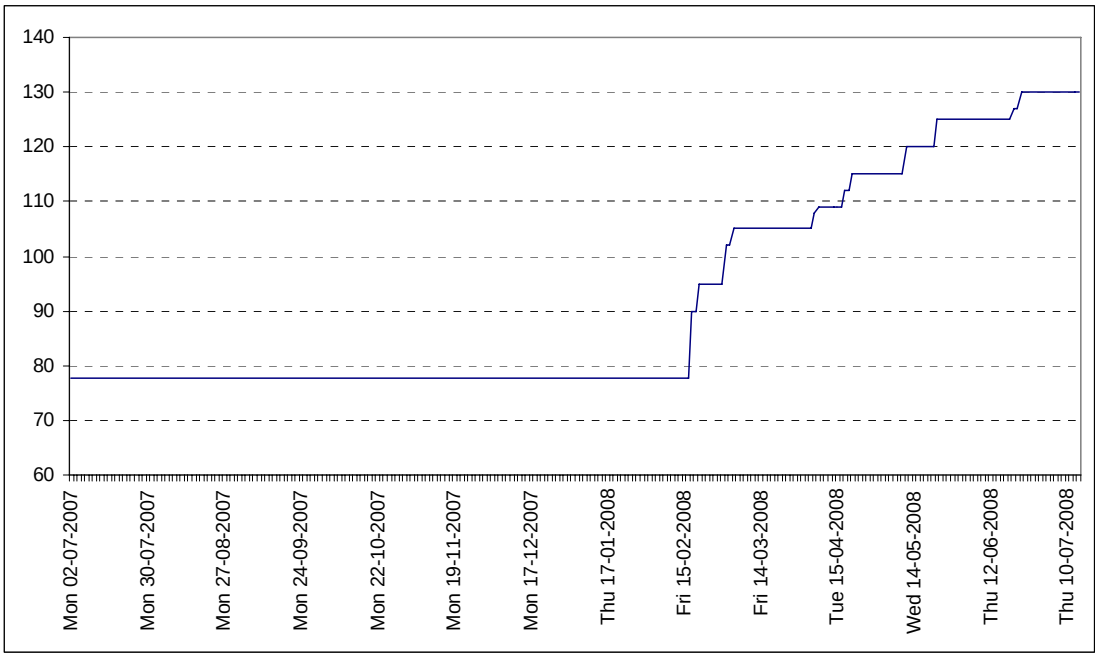
Figure 26: d-cypha Trade prices for Queensland peak swap contracts for Q4 2009 – October to December 2009



Source: d-Cypha Trade data

E.2.3 Q1 2010 – January to March 2010

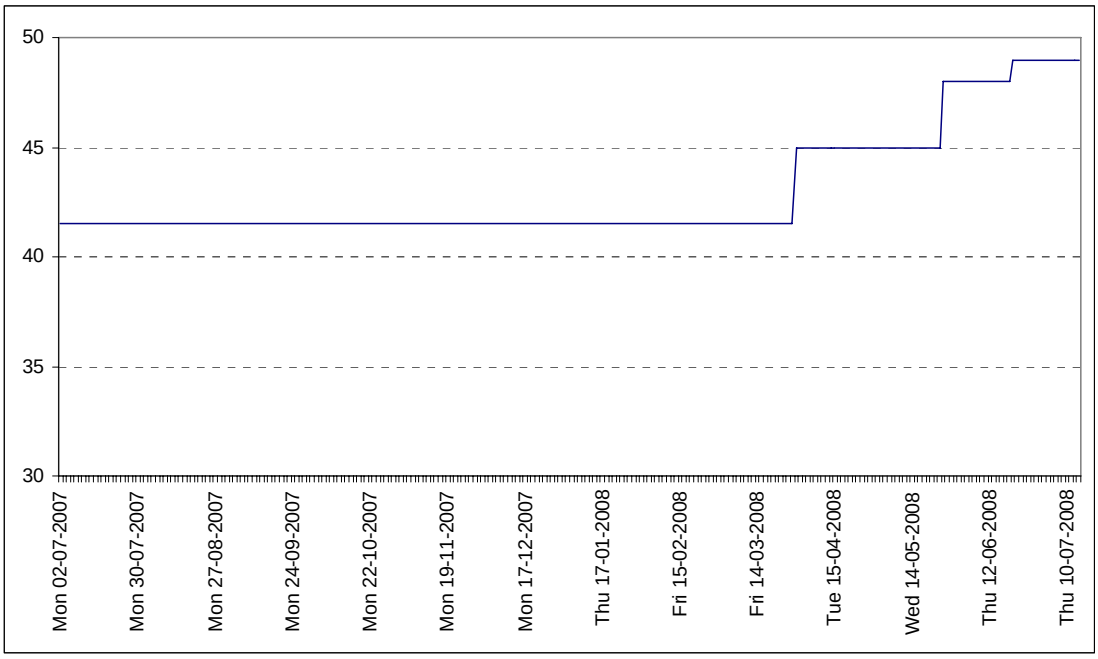
Figure 27: d-cypha Trade prices for Queensland peak swap contracts for Q1 2010 – January to March 2010



Source: d-Cypha Trade data

E.2.4 Q2 2010 – April to June 2010

Figure 28: d-cypha Trade prices for Queensland peak swap contracts for Q2 2010 – April to June 2010

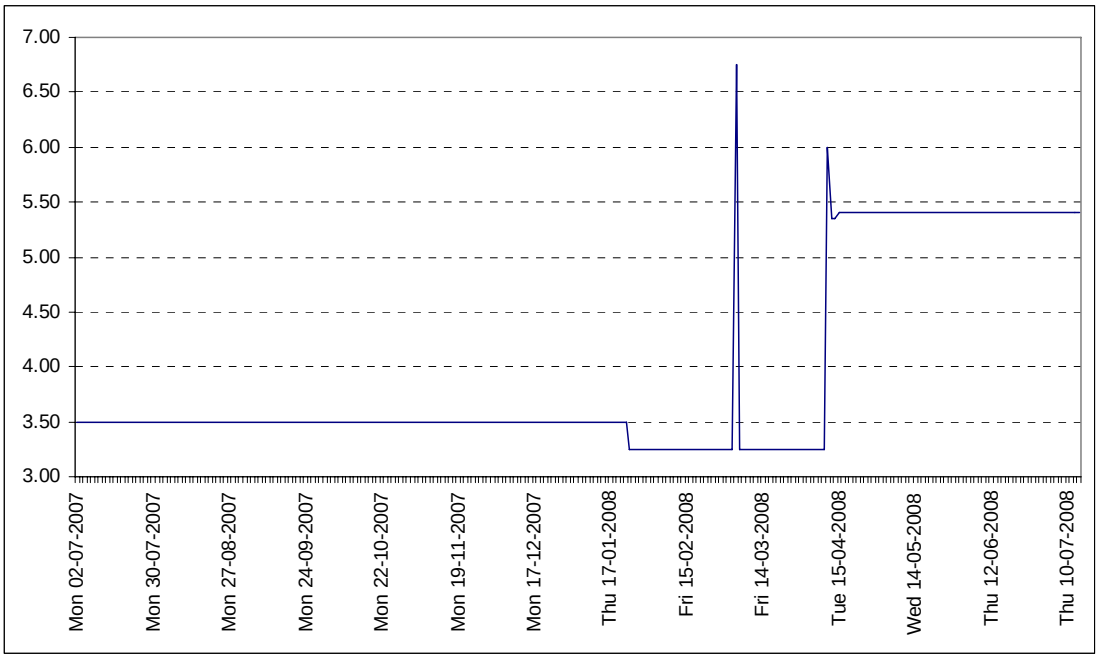


Source: d-Cypha Trade data

E.3 CAP CONTRACT PRICES (AT $300 CAP)

E.3.1 Q3 2009 – July to September 2009

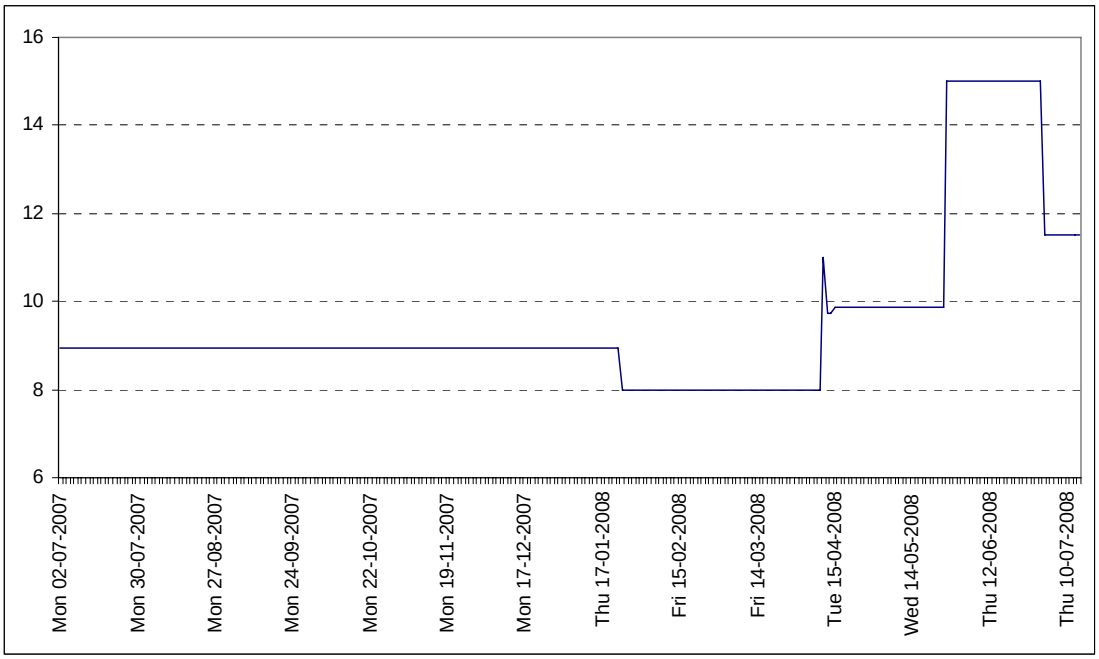
Figure 29: d-cypha Trade prices for Queensland $300 cap contracts for Q3 2009 – July to September 2009



Source: d-Cypha Trade data

E.3.2 Q4 2009 – October to December 2009

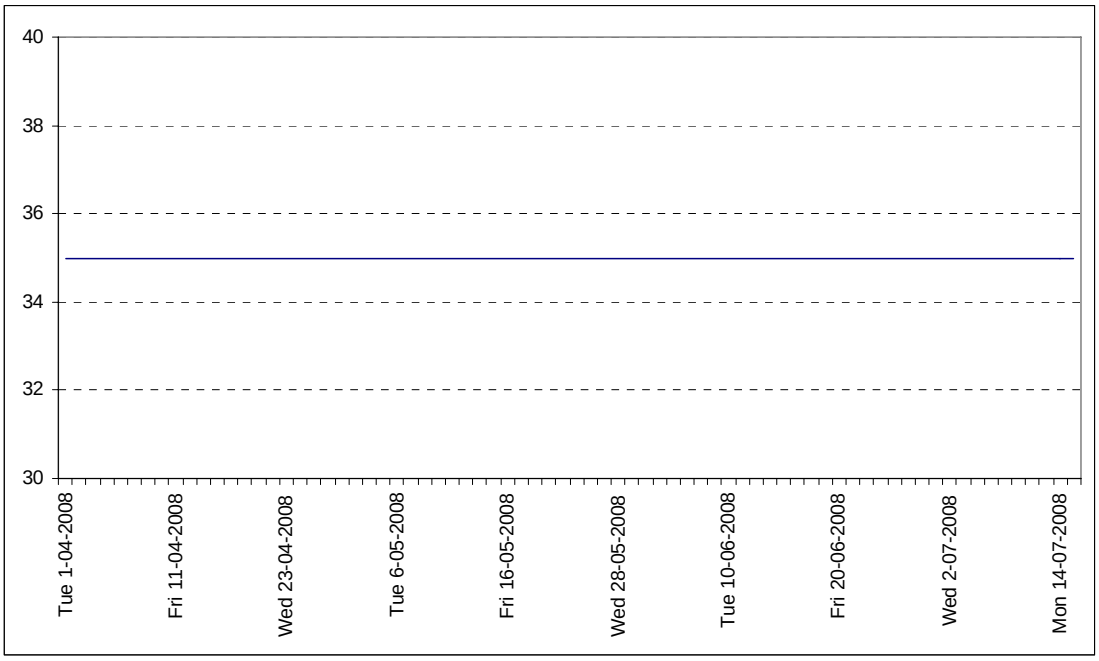
Figure 30: d-cypha Trade prices for Queensland $300 cap contracts for Q4 2009 – October to December 2009



Source: d-Cypha Trade data

E.3.3 Q1 2010 – January to March 2010

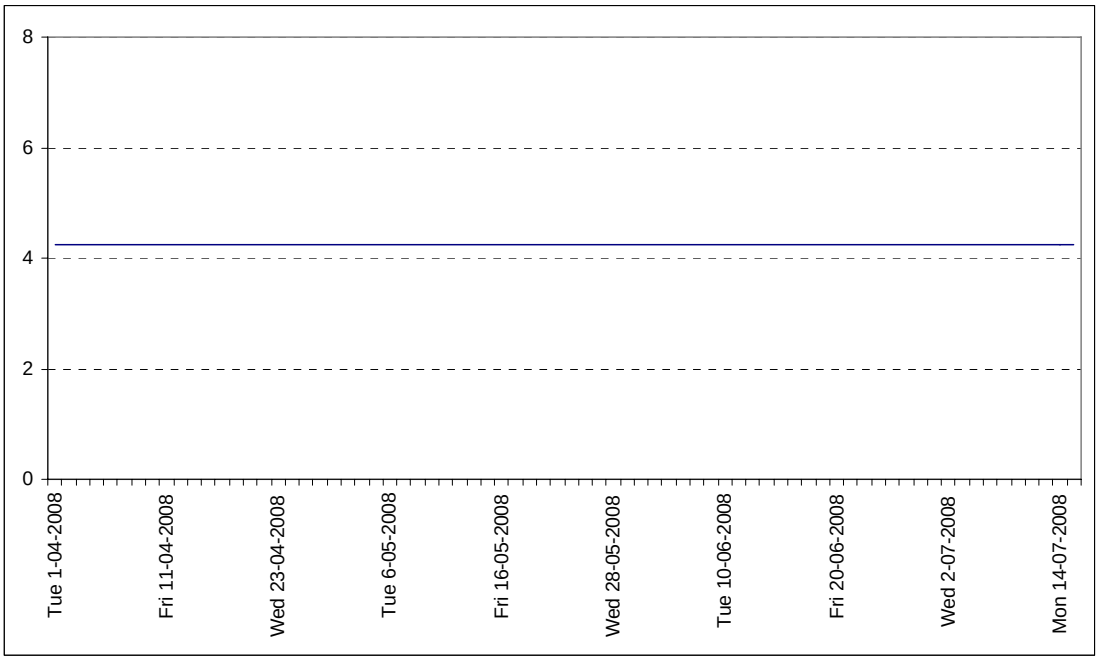
Figure 31: d-cypha Trade prices for Queensland $300 cap contracts for Q1 2010 – January to March 2010



Source: d-Cypha Trade data

E.3.4 Q2 2010 – April to June 2010

Figure 32: d-cypha Trade prices for Queensland $300 cap contracts for Q2 2010 – April to June 2010



Source: d-Cypha Trade data

APPENDIX F: INPUT ASSUMPTIONS – DATA SHEET

F.1 INPUT DATA FOR LRMC CALCULATION

F.1.1 Load data

Peak and energy projections

Peak and energy projections are used along with the 2008 calendar year load to forecast a Load Duration Curve (LDC) for each jurisdiction in each year over the duration of the model run. These projections come from NEMMCO's report "2008 Energy and maximum Demand Projections" which was released in July 2008. The LRMC calculation assumes a medium economic growth scenario and a 50POE temperature scenario.

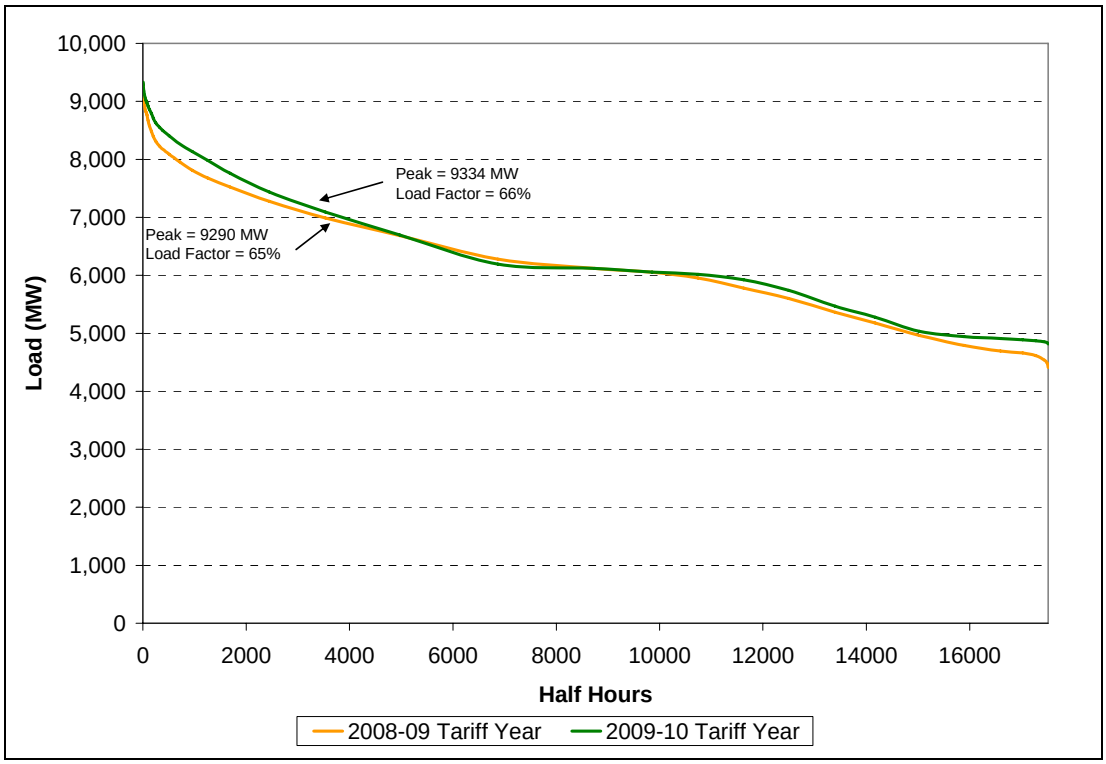
40 load block LDC for Queensland in the 2009-10 tariff year

As discussed in the body of the report, CEMOS uses a 40 load block approach when solving for the LRMC. Table 30 outlines the details of the 40 load blocks that were generated for Queensland in the 2009-10 LRMC calculation, namely the load that each block represents and the number of hours in the year that the block represents. The corresponding LDC is shown in Figure 33 which also compares this to the LDC used for the previous 2008-09 tariff year LDC calculation.

Table 30: Details of the 40 load blocks for Queensland in the 2009-10 tariff year LRMC calculation

Block	Load (MW)	Hours in year	Block	Load (MW)	Hours in year
1	9334.46	1	**21**	7760.82	215
2	9306.59	1	**22**	7436.59	382
3	9280.07	2	**23**	7094.31	542
4	9228.12	2	**24**	6698.29	719
5	9178.21	3	**25**	6193.33	949
6	9117.14	6	**26**	6118.89	939
7	9060.70	8	**27**	6058.04	554
8	9015.94	6	**28**	6017.45	445
9	8973.32	10	**29**	5925.25	442
10	8918.84	12	**30**	5741.39	435
11	8859.99	13	**31**	5469.14	451
12	8793.97	17	**32**	5278.15	386
13	8709.75	19	**33**	5034.32	427
14	8629.20	24	**34**	4943.40	432
15	8553.96	37	**35**	4910.40	353
16	8497.18	31	**36**	4889.66	216
17	8404.64	63	**37**	4871.02	127
18	8269.55	100	**38**	4854.87	80
19	8134.38	123	**39**	4838.34	30
20	7982.35	149	**40**	4817.54	9

Figure 33: Queensland's 2009-10 tariff year LDC compared to the 2008-09 tariff year LDC



F.1.2 Generator capital cost data

Table 31: Capital costs used in the 2009-10 tariff year LRMC calculation

	Capital Cost (2009/10$/kW)	Annualised Capital Cost ($/MW/year)	Source[94]
Black Coal	1,769	175,250	ACIL 2007, Table 78
Brown Coal	1,977	195,856	ACIL 2007, Table 79
CCGT	1,092	108,181	ACIL 2007, Table 77
OCGT	749	74,201	ACIL 2007, Table 81
Wind	2,353	233,092	AEO 2007
Hydro	2,705	268,022	CRC CCSD
Geothermal	2,146	212,635	Average of AEO 2007 and AEO 2008
Biomass	3,336	330,536	Average of AEO 2007 and AEO 2008

F.1.3 Generator operating cost data

Table 32: FOM and VOM used in the 2009-10 tariff year LRMC calculation

	FOM (2009/10$/MW/year)	VOM (2009/10$/MWh)
Black Coal	42,025	1.26
Brown Coal	42,025	1.26
CCGT	13,448	5.10
OCGT	7,880	7.88
Wind	42,025	0

94 Data sources:

Fuel resource, new entry and generation costs in the NEM, Report 2 – Data and documentation, Report prepared for NEMMCO, ACIL Tasman, June 2007.

Assumptions to the Annual Energy Outlook, US Energy Information Administration, April 2007 and April 2008.

Options for Electricity Generation in Australia, Cooperative Research Centre for Coal in Sustainable Development (CRC CCSD), Technology Assessment Report, P. Graham et al, 31 January 2005.

	FOM (2009/10$/MW/year)	VOM (2009/10$/MWh)
Hydro	52,531	7.35
Geothermal	54,965	0
Biomass	153,638	4.60

F.1.4 Generator fuel cost data

Coal

Table 33: Coal fuel costs used in the 2009-10 tariff year LRMC calculation

	Queensland (2009/10$/GJ)	New South Wales (2009/10$/GJ)	Victoria (2009/10$/GJ)
2009/10	0.9876	1.1137	0.5673
2010/11	0.9876	1.1067	0.5673
2011/12	0.9841	1.1067	0.5673
2012/13	0.9806	1.1067	0.5673
2013/14	0.9771	1.1032	0.5673
2014/15	0.9771	1.0962	0.5673
2015/16	0.9771	1.0962	0.5673
2016/17	0.9701	1.0962	0.5568
2017/18	0.9666	1.0927	0.5568

Gas delivered to CCGT plant

We adopted the same method for calculating gas costs as was used for the 2008-09 LRMC calculation. Costs for gas delivered to CCGT plant were developed by a "trended cost" method using ABARE information on the spot price of gas in Victoria over the years 2002-03 through 2006-07 inclusive,[95] as shown in Table 34 below.

95 *Energy in Australia 2008*, ABARE, February 2008.

Table 34: Victoria gas spot prices (real 2006-07 $/GJ)[96]

	2002-03	2003-04	2004-05	2005-06	2006-07
Gas spot prices	$3.20	$3.22	$3.17	$3.25	$3.36
Year on year % change	-	0.63%	-1.55%	2.52%	3.38%

Source: ABARE

As in the 2008-09 tariff year LRMC calculation, a transportation cost of $0.50/GJ was added in real dollars to the price in each year, and then a linear trend line was determined for this price path and extended to 2009-10. Nominal prices were then derived for the 2009-10 tariff year by applying the long-run annual inflation factor of 2.5%. Lastly, the nominal Victoria prices were used to derive 2009-10 prices in the other NEM states by reference to the relativities between the average prices of gas in Victoria and the various other states as shown in the ACIL 2007 report. Table 35 below shows CCGT fuel costs over the LRMC modelling horizon for each NEM jurisdiction.

Table 35: CCGT fuel costs used in the 2009-10 tariff year LRMC calculation

	Queensland (2009/10$/GJ)	New South Wales (2009/10$/GJ)	Victoria (2009/10$/GJ)	South Australia (2009/10$/GJ)	Tasmania (2009/10$/GJ)
2009/10	3.8934	4.2376	4.2160	4.6793	4.3757
2010/11	3.9283	4.2755	4.2537	4.7211	4.4148
2011/12	3.9631	4.3134	4.2914	4.7630	4.4539
2012/13	3.9979	4.3512	4.3291	4.8048	4.4930
2013/14	4.0327	4.3891	4.3668	4.8466	4.5321
2014/15	4.0675	4.4270	4.4045	4.8885	4.5712
2015/16	4.1023	4.4649	4.4422	4.9303	4.6104
2016/17	4.1371	4.5028	4.4799	4.9721	4.6495
2017/18	4.1719	4.5407	4.5176	5.0140	4.6886

96 Calculated as financial year averages of daily spot prices in the Victorian gas market.

Gas delivered to OCGT plant

The trended cost of gas delivered to OCGT plant in each state was estimated by applying the 125% factor cited in the ACIL 2007 report to the delivered price of gas to CCGT plant determined for each state for the 2009-10 tariff year. Table 36 below shows OCGT fuel costs over the LRMC modelling horizon for each NEM jurisdiction.

Table 36: OCGT fuel costs used in the 2009-10 tariff year LRMC calculation

	Queensland (2009/10$/GJ)	New South Wales (2009/10$/GJ)	Victoria (2009/10$/GJ)	South Australia (2009/10$/GJ)	Tasmania (2009/10$/GJ)
2009/10	4.8668	5.2970	5.2700	5.8491	5.4696
2010/11	4.9103	5.3443	5.3171	5.9014	5.5185
2011/12	4.9538	5.3917	5.3643	5.9537	5.5674
2012/13	4.9973	5.4391	5.4114	6.0060	5.6163
2013/14	5.0408	5.4864	5.4585	6.0583	5.6652
2014/15	5.0844	5.5338	5.5056	6.1106	5.7141
2015/16	5.1279	5.5811	5.5527	6.1629	5.7630
2016/17	5.1714	5.6285	5.5998	6.2152	5.8119
2017/18	5.2149	5.6758	5.6469	6.2675	5.8608

Fuel costs for biomass generators

The fuel cost is taken from the CCSD Technology Assessment Report 72, published 2008. This report outlined that biomass fuel cost would be, on average, $1.50/GJ. This estimate was in 2005 dollars, so CPI has been applied for the cost to be $1.576/GJ in 2009-10 dollars.

Fuel costs for other generators

Wind, hydro and geothermal generators do not incur fuel costs.

F.1.5 Thermal Efficiency

Table 37: Thermal efficiency and auxiliary factors used in the 2009-10 LRMC calculation

Plant type	Thermal efficiency	Auxiliaries
Supercritical black coal	42%	7.5%
CCGT	52%	2.4%
OCGT	31%	2.0%
Wind	n.a.	0%
Hydro	n.a.	0%
Geothermal	10%	0%
Biomass	38%	0%

F.1.6 Availability

Table 38: Availability factors used in the LRMC modelling

	Availability factor	Data source
Black coal	91.78%	ANTS
Brown Coal	90.43%	ANTS
OCGT	97%	ACIL 2008
CCGT	90.99%	ANTS
Wind	93.40%	ANTS
Hydro	92.20%	ANTS
Geothermal	90%	CRA Assumption
Biomass	85%	CRA Assumption

F.1.7 WACC

CEMOS uses the pre-tax real weighted average cost of capital (WACC) in two ways:

- The generation capital costs in the model are annualised using the WACC; and
- When the model optimises total costs (including fuel cost or generator offer costs, annualised capital costs, the cost of unserved energy, and O&M costs), all future costs are discounted to the first year (2007) using the WACC.

Table 39: WACC assumptions

Parameter	Value
Input parameters	
Liabilities	100%
Debt	60%
Equity	40%
Risk-free rate of return	5.70%
Risk premium	6.00%
Market rate of return	11.70%
Corporate tax rate	30%
Effective tax rate	22.50%
Debt basis point premium	200
Cost of debt	7.70%
Gamma	0.5
Asset beta	0.8
Debt beta	0.16
Equity beta	1.75
Required return on equity	16.21
Inflation	2.50%
WACC values	
Post tax nominal WACC	9.25%
Post tax real WACC	6.58%
Pre-tax nominal WACC	11.93%
Pre-tax real WACC	**9.20%**

Source: ACIL 2007 Report, page 125

F.1.8 Project life

The LRMC calculation for the 2009-10 tariff year uses a project life of 30 years for all types of generation plants.

F.1.9 Permit prices

Table 40: Permit prices used in the LRMC modelling

Year	10% case permit price ($/tonne CO2)	20% case permit price ($/tonne CO2)
2009/10	-	-
2010/11	20.00	20.00
2011/12	27.50	30.00
2012/13	32.50	38.00
2013/14	37.00	42.00
2014/15	39.00	46.00
2015/16	41.00	47.50
2016/17	42.00	50.00
2017/18	43.00	52.00

F.1.10 Renewable Energy Targets

Table 41: Calculating NEM sent-out generation as a % of total Australian sent-out generation

	Sent-out generation (GWh year ending 30 June 2007)	NEM jurisdiction?
NSW & ACT	65549	Yes
VIC	49293	Yes
QLD	55578	Yes
SA	11814	Yes
WA	15341	No
TAS	9252	Yes
NT	1405	No
Snowy	2940	Yes
Total all jurisdictions	211,171	-
Total NEM	194,426	-
NEM % of total	**92.07%**	-

Table 42: Annual Renewable Energy Targets

Year	Renewable Energy Target (GWh/year)
2009/10	8,747
2010/11	9,480
2011/12	11,069
2012/13	12,923
2013/14	15,089
2014/15	17,618
2015/16	20,570
2016/17	24,018
2017/18	28,042