



Final Decision

2009-10 Benchmark Retail Cost Index

June 2009

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PREAMBLE

Since the introduction of full retail competition (FRC), small electricity consumers have been able to purchase electricity from the retailer of their choice or remain on a notified (regulated) tariff. A small consumer is one who consumes less than 100 Megawatt hours (MWh) per annum, which equates to an annual electricity bill of around \$15,000 per annum. A small electricity consumer can also choose to return to a regulated tariff on the expiry of the contract with their chosen retailer.

Prior to the introduction of FRC, regulated tariffs were set by the Government. To ensure that regulated tariffs keep pace with the costs of producing, transporting and retailing electricity, the Authority is required to estimate the increase in these costs annually and to apply that increase to the existing regulated tariffs.

In this Final Decision, the Authority estimates the increase in costs to be 11.82% between 2008-09 and 2009-10. This increase is made up of:

- (a) an increase in energy costs of 12% (accounting for 45% of the total change) reflecting the impact of rising fuel and capital costs;
- (b) an increase in transmission and distribution costs of 12.3% (accounting for 48% of the total change) reflecting ongoing significant investment in the distribution networks; and
- (c) an increase in retail costs of 8.7% (accounting for the remaining 7% of the total change), reflecting mainly the fact that the retail margin increases proportionately with the increase in all other costs.

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1. INTRODUCTION

Under the Electricity Act 1994 (the Electricity Act), the rate of change in the Benchmark Retail Cost Index (BRCI) is used to adjust notified electricity prices each year.

The Minister for Mines and Energy (the Minister) has delegated responsibility for calculating the 2009-10 BRCI to the Queensland Competition Authority (the Authority). This delegation requires the Authority to calculate the BRCI for 2009-10, apply the annual change in the BRCI to notified prices and publish new notified prices for 2009-10. In accordance with his revised delegation of 3 June 2009, new notified prices are to be gazetted no later than 12 June 2009.

1.1 Background

Full retail competition (FRC) in Queensland energy markets commenced on 1 July 2007. With the introduction of FRC, electricity retailers are able to offer to supply electricity to all consumers, including those on notified (regulated) prices. Consumers taking up such an offer transfer from the notified price to the market contract price they have accepted from the retailer.

However, notified electricity prices remain an important feature of the Queensland electricity market. In particular, customers who are not offered a market contract, or who choose not to accept an offer, remain on a notified price. In addition, small consumers who accept a market contract may revert to a non-market contract at the notified price in the future, subject to any contractual conditions that may apply to their market contract. In effect, the notified price sets a ceiling on the basic price that consumers are required to pay.

The Electricity Act provides for the notified price of electricity to be adjusted annually according to changes in the cost of providing electricity. Specifically, the rate of change in the BRCI is to be used to adjust notified electricity prices each year.

1.2 Scope of this Decision

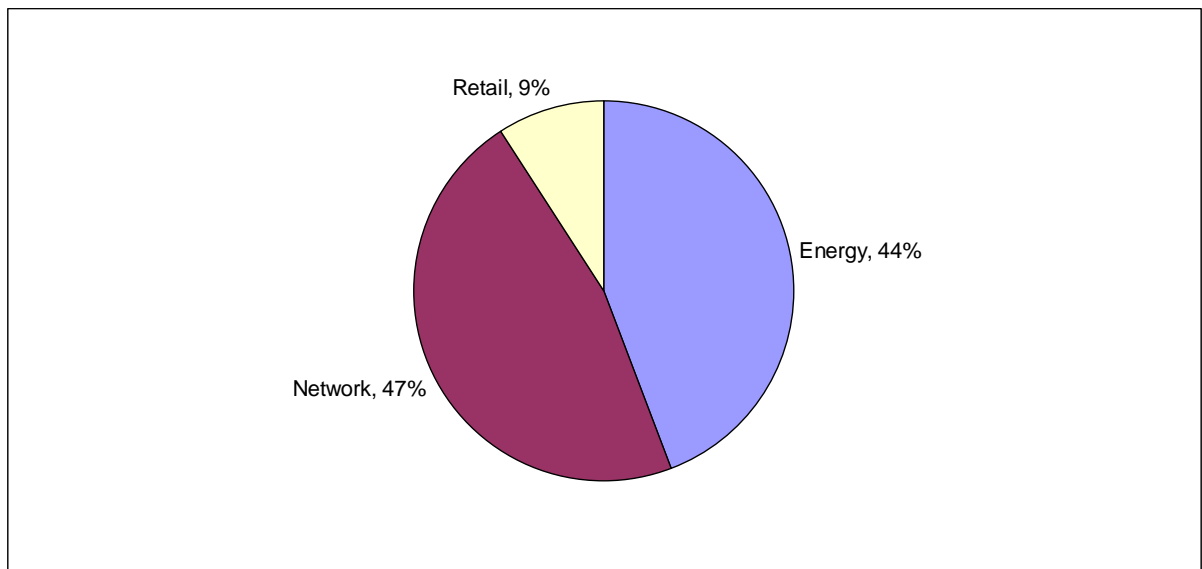
This report outlines the Authority's Final Decision regarding the BRCI for 2009-10. It does not seek to either reiterate in detail matters previously considered by the Authority in past decisions or to detail the modelling undertaken to inform this decision.

As such, this Final Decision should be read in conjunction with relevant public reports that are referenced herein.

1.3 Overview of the BRCI

The BRCI approach to the determination of the notified price of electricity does not involve a calculation of the efficient retail price of electricity each year. Rather, existing notified electricity prices are escalated by the expected change in the underlying cost of supplying electricity to consumers (that is, by the change in the BRCI).

The BRCI has three main components, namely: the cost of energy; network costs; and retail costs. The approximate sizes of the cost components are illustrated in Figure 1.1.

Figure 1.1 – Cost Components in the Supply of Electricity 2009-10

Source: QCA

The impact on notified prices for electricity of a change in any component of the BRCI will reflect both the size of the change and the weighting of the component in the overall BRCI.

As network costs (transmission and distribution) and the cost of energy (generation) account for around 91% of the total cost of supplying energy, changes in these components will usually have the greatest impact on movements in the index from one year to the next.

In considering the components of the BRCI, the Authority is required to comply with the provisions of the Electricity Act and the Electricity Regulation 2006 (the Electricity Regulation). These can be obtained from:

- <http://www.legislation.qld.gov.au/legisltn/current/e/electrica94.pdf>; and
- <http://www.legislation.qld.gov.au/legisltn/current/e/electricr06.pdf>.

The Electricity Act allows the Minister to delegate the calculation of the BRCI to the Authority. On 26 August 2008, the Minister provided the Authority with a certificate of delegation in relation to the 2009-10 BRCI Decision. This was replaced on 5 February 2009 by a revised delegation from the Minister. On 3 June 2009, the Minister provided a further revised delegation (Current Delegation). The Current Delegation, which is at **Attachment 1**, is the basis upon which this Final Decision has been prepared. The Current Delegation requires the Authority to:

- (d) calculate the BRCI;
- (e) apply the change in the BRCI to the existing schedule of notified prices; and
- (f) publish, by gazette notice, the new schedule of notified prices for 2009-10 no later than 12 June 2009.

Three conditions attach to the Current Delegation:

- (a) annual indexation of electricity tariffs should ensure that retail headroom in the tariffs as at the date of the Original Delegation¹ remains relatively stable (although not necessarily the same from year to year);
- (b) the policy of enabling small market customers to revert to notified prices should not result in a retail entity providing retail services to such customers at a loss; and
- (c) the network cost component of the BRCI must be calculated by applying the annual aggregate revenue requirements (AARRs) determined for each year of Ergon Energy's current access arrangement, including any changes to those AARRs for any approved cost pass-through, without undertaking any re-smoothing of the AARR amounts.

1.4 Calculation of the BRCI for 2009-10

On 2 July 2008, the Authority released an Interim Consultation Notice advising interested parties of the process for calculating the BRCI for 2009-10 and seeking comment on all aspects of the calculation of the BRCI. Nine submissions were received by the Authority. A copy of the Notice and the submissions received can be obtained from the Authority's website.

The Authority engaged CRA International (CRA) to provide expert advice on the cost of energy, retail costs and retail margins to be included in the BRCI for 2009-10. CRA was also required to provide an estimate of the overall percentage change in the BRCI from 2008-09 to 2009-10 based on its own cost estimates for those elements and the Authority's estimates of network costs and the electricity load for Queensland.

On 15 August 2008, the Authority released a first draft report from CRA accompanied by supporting data and, on 27 August 2008, hosted a workshop to provide stakeholders with an opportunity to discuss all aspects of the report, including CRA's estimates of the BRCI cost components and the methods used to calculate these estimates. The workshop was attended by 24 stakeholders representing 13 organisations, including representatives from retailers, large consumers of electricity, consumer groups and Government.

Following this workshop, the Authority engaged ACIL Tasman (ACIL) to provide advice on capital and fuel costs to be used by CRA in its modelling exercise.

Origin (2008b) and AGL (2008b) provided written comments following the first workshop.

A draft report from ACIL and a second draft report and updated data files from CRA were released for comment on 28 October 2008. The Authority hosted a second workshop on 3 November 2008 to discuss both reports. This workshop was attended by 17 stakeholders representing 11 organisations. Following the workshop, the Authority worked with CRA and some stakeholders to revise some input data which was subsequently released on the Authority's website.

Four submissions were received from retailers following the second workshop.

The issues raised in all submissions (which can be accessed on the Authority's website), as well as the discussions at the workshops, were addressed by the Authority in preparing its Draft Decision which was released on 2 December 2008 along with a final draft report from CRA and a final report from ACIL.

¹ The Original Delegation was issued by the Minister to the Authority on 16 March 2007.

Nine submissions were received from stakeholders in response to the Draft Decision.

Following receipt of the delegation of 5 February, which extended the reporting deadline to 30 May 2009, and in light of comments made by the Minister in his covering letter referring to the rapidly changing economic environment and the desirability of the Authority's decision being informed by "the most reliable and up to date data", the Authority invited further submissions from stakeholders, to be considered along with issues raised in earlier submissions. The Authority received two submissions in response to this invitation.

The Authority also engaged Concept Economics to provide advice on the likely impact of the deteriorating global economic environment on the forecast input costs previously provided by ACIL for the Draft Decision and which had been prepared at a time when the future economic outlook was considerably more buoyant.

On 28 April 2009, judgment was handed down by Justice P McMurdo of the Supreme Court of Queensland on applications from AGL and Origin Energy for Judicial Review of the Authority's 2008-09 BRCI Decision (this issue is discussed further in the following chapter). The judgment set aside the 2008-09 BRCI Decision and required the Authority to adopt a different approach to the calculation of energy purchase costs and, as a general rule, not to update data used between making a Decision on the BRCI for one tariff year (B_y) and the use of that BRCI (now as the base year, B_{y-1}) in the subsequent calculation of the BRCI for the following tariff year.

As the approach taken in the 2009-10 BRCI Draft Decision was essentially the same as that followed in the 2008-09 Final Decision, the judgment had implications for the 2009-10 decision.

On 8 May 2009, the Authority released a Consultation Paper on the determination of the relevant load to be used to calculate the cost of purchasing energy in order to comply with the judgement. In the Consultation Paper, the Authority proposed adopting the method for constructing forecast NEM load traces recommended by ACIL.

Four submissions were received in response to the Consultation Paper. While the Authority gave careful consideration to the issues raised in those submissions and subsequent correspondence from AGL and Origin Energy, it concluded that the ACIL approach to calculating the NEM load traces is sound and provides robust forecasts of the relevant loads.

On 19 May 2009, the Authority released the half-hourly NEM load trace forecasts prepared by ACIL for 2007-08, 2008-09 and 2009-10 for the information of interested parties.

In making this Final Decision, the Authority has had regard for all submissions received from stakeholders throughout the process, reports received from CRA, ACIL and Concept Economics, the judgement and orders of the Supreme Court of Queensland made in relation to the applications from AGL and Origin Energy for Judicial Review of the Authority's 2008-09 Decision, as well as its own investigations.

A copy of this Final Decision, submissions and reports from the Authority's consultants can be obtained from the Authority's web site at www.qca.org.au.

2. JUDICIAL REVIEW OF THE 2008-09 BRCI

AGL (14 August 2008) and Origin Energy (1 September 2008) sought judicial review of the Authority's 2008-09 BRCI Final Decision.

On 2 December 2008, the Authority released its Draft Decision on the Benchmark Retail Cost Index (BRCI) for 2009-10.

On 28 April 2009, judgment was handed down by Justice P McMurdo of the Supreme Court of Queensland on the 2008-09 Judicial Review application. The judgement set aside the Authority's 2008-09 Decision and required that it be remade in a manner consistent with the judgement.

As the approach taken in the 2009-10 BRCI Draft Decision was essentially the same as that followed in the 2008-09 Final Decision, the judgment has implications for the 2009-10 Final Decision.

2.1 Background

The Authority released its Draft Decision on the Benchmark Retail Cost Index (BRCI) for 2009-10 on 2 December 2008. At that time, it estimated the increase in costs between 2008-09 and 2009-10 to be 13.63%.

Prior to this, AGL (14 August 2008) and Origin Energy (1 September 2008) had sought a judicial review of the Authority's 2008-09 BRCI Final Decision. On 28 April 2009, judgment was handed down by Justice P McMurdo of the Supreme Court of Queensland (the judgment).

The judgment, cited as *AGL Energy Ltd v Queensland Competition Authority & Anor; Origin Energy Retail Ltd v Queensland Competition Authority & Anor* [2009] QSC 90, is available from the Queensland Supreme Court registry website at www.courts.qld.gov.au.

As the approach taken in the 2009-10 BRCI Draft Decision was essentially the same as that followed in the 2008-09 Final Decision, the judgment has implications for the 2009-10 decision.

In its judgment, the Court found that:

- (a) in working out the benchmark retail cost for both the relevant tariff year and the preceding tariff year, the Authority incorrectly calculated the purchase cost of energy on the basis of the load shape of the total State load and not the load shape of the NEM load as defined under the Electricity Act, being the total State National Electricity Market (NEM) load less the load of customers directly connected to the transmission network; and
- (b) in working out the total benchmark retail cost for the preceding year, the Authority used data which had not been available when the year to 30 June 2008 had been the relevant tariff year, and which the Authority was not otherwise entitled to use.

On 14 May 2009, the court ordered that:

- (a) the 2008-09 BRCI Decision be set aside;
- (b) the Authority is required to re-make its 2008-09 Decision according to law and according to these orders;

- (c) the Authority recalculate the 2007-08 BRCI, and decide the BRCI for 2008-09, on or before 29 May 2009 (“Remade Decision”);
- (d) the Authority calculate notified prices for the 2008-09 tariff year by reference to the Remade Decision, and, by gazette notice, publish those notified prices (“2008-09 Notified Prices”);
- (e) the gazette notice referred to in the preceding orders be in terms and be published so that the 2008-09 Notified Prices take effect immediately before the commencement of the 2009-2010 tariff year; and
- (f) the Authority calculate notified prices for the 2009-2010 tariff year by reference to the Remade Decision and the 2008-09 Notified Prices.

2.2 Changes resulting from judicial review of the 2008-09 BRCI

The 2009-10 BRCI Final Decision must be made on a basis that accords with the judgment and is consistent with the orders noted above. This requires an approach that is different, in two ways, from the approach proposed in the Authority’s Draft Decision:

- (a) the energy purchase costs of supplying the NEM load must be based on the load profile of the NEM load as defined in the Electricity Act, rather than the load profile of the total State NEM load as had been done previously; and
- (b) the BRCI for the preceding year (2008-09) will, as a general rule, need to be the same as that calculated in the preceding BRCI Decision in terms of both the data used and the methods applied, except to the extent that there is a change in method (which would trigger a recalculation between Decisions) and the data requirements of the new method were not available at the time of the previous Decision.

Accordingly, the 2009-10 calculation of energy purchase costs will be different to that proposed in the Draft Decision but will be consistent with the judgment and calculated on the same basis as in the Remade Decision.

In relation to the data used, the judgment discussed the use of new data that had no connection with a change in methodology when calculating the prior year’s BRCI for use as the denominator in the calculation of the current year’s BRCI increase. While the judgment indicated there may be occasions when it would be valid for the Authority to use different data in recalculating the BRCI (outside of a methodology change) even though the old data could have been employed, it would not usually be in accord with the purpose of the BRCI regime.²

On this basis, the Authority considers that it is not able to use more recent data, correct identified errors or in any other way amend the 2008-09 year BRCI in this decision as it is of the view that there are no special circumstances which would justify it doing so on this occasion.

Finally, and consistent with the Court orders, the Authority has applied the change in the BRCI estimated under this current Final Decision for 2009-10 to the 2008-09 notified prices calculated under the Remade Decision.

The change in the 2008-09 notified prices which result from the Remade Decision will have a significant impact on the notified prices for 2009-10.

² AGL Energy Ltd v Queensland Competition Authority & Anor; Origin Energy Retail Ltd v Queensland Competition Authority & Anor (2009) QSC90 at [96].

The impact of the judicial review on the 2009-10 BRCI Decision is discussed where relevant in the following chapters.

3. COST OF ENERGY

The Electricity Act requires that the cost-of-energy component of the BRCI in a particular year be based on the Authority's view of the likely total cost of purchasing energy to supply the NEM load in that year. In forming this view, the Authority is required to base its view on its latest estimate of the long run marginal cost (LRMC) of energy in that part of Queensland connected to the national grid and take account of the actual cost of purchasing energy to meet the NEM load.

In estimating the cost of energy component for the 2009-10 BRCI, the Authority estimated the LRMC of energy and the purchase cost of energy and then calculated an (equally) weighted average of these two costs. This is the same approach as adopted in the 2008-09 BRCI Decision.

The LRMC of energy was estimated based on a hypothetical economically efficient combination of generating technologies for Queensland. The interconnection of the Queensland electricity network with the rest of the NEM was taken into account as were projected changes in the LRMC of energy over time. In arriving at its estimate of the change in LRMC for 2009-10, the Authority elected to continue with the same basic approach adopted in the previous year of basing input costs on a trend regression analysis, albeit updated since the Draft Decision to reflect more recent cost data.

The purchase cost of energy was estimated based on a combination of contract and spot market energy prices that a prudent and efficient retailer could be expected to purchase over a two-year period in order to meet the NEM load. The calculation of purchase costs differs from that used in the Draft Decision in order to be consistent with the recent judgment in relation to the judicial review of the Authority's 2008-09 BRCI Decision. The method used here is the same as that used in the Authority's remade 2008-09 BRCI Decision.

In establishing the cost-of-energy component of the BRCI, the Electricity Act also requires the Authority to consider the impact of the 13% gas scheme and the Mandatory Renewable Energy Target (MRET) scheme (under the Renewable Energy (Electricity) Act 2000). These costs were estimated using publicly available prices for Renewable Electricity Certificates and the penalty cost to retailers for not surrendering sufficient Gas Electricity Certificates.

The Authority also included the cost of NEM participant fees and ancillary services charges paid by retailers.

Summing the energy costs described above, the estimated total energy-cost component of the BRCI is \$2,025 million in 2008-09 and \$2,255 million in 2009-10, an increase of 11.4%.

3.1 Background

Typically, electricity is purchased by retailers from generators on behalf of their customers and delivered via transmission and distribution networks to customers' homes and businesses. At any point in time, the cost of energy to a retailer will generally reflect the various supply contracts the retailer has with generators as well as the prevailing demand and supply conditions in the market.

In the short run, a retailer will overcome any shortfall in the amount of electricity it needs to meet customer demand by purchasing energy through the NEM. This market price therefore represents the short run marginal cost of energy and is the basis of the energy purchase costs.

In the long run, costs should tend to be more stable. Short-run peaks and troughs are less relevant when considering the cost of supplying electricity to the market over a longer period.

The long-run cost of purchasing additional units of electricity will tend to reflect the cost of replacing outdated generating capacity. The long run marginal cost (LRMC) of energy should be more stable and influenced by the changing costs of technology rather than the day-to-day supply and demand imbalances that affect the energy purchase costs.

Long Run Marginal Cost

In general terms, the LRMC of supply is considered to be the cost of providing an additional unit of capacity over a period in which all production factors are variable (the long run).

The Authority's approach to calculating the LRMC of energy in the 2009-10 BRCI is driven by the legislation which requires a greenfields approach be adopted. The LRMC calculation has the following features:

- (a) Queensland's electricity grid is treated as part of the NEM rather than as an isolated region from a generation perspective;
- (b) a 'greenfields approach' is used which assumes that the entire generation system is built new at the outset using the most efficient combination of new plant to meet the nominated load;
- (c) modelling uses a multi-year approach which attempts to capture the range and effect of variables (such as weather) over the longer term in identifying the optimal mix of plant chosen, but is calculated based on the lowest cost combination of generating plant to meet the projected load from a base year;
- (d) the modelling approach also optimises generation investment across the NEM regions after taking account of the characteristics of the existing transmission system; and
- (e) a load 'shape' which is developed on the basis of each half-hour period for the previous calendar year.

Energy Purchase Costs

The Authority is also required to take into account its view of the likely costs of purchasing electricity to meet the NEM load in the tariff year. This is a short term measure of energy supply costs and, in theory, is likely to be more volatile than LRMC.

To estimate energy purchase costs, the Authority must come to a view about the purchasing decisions that would be made by a prudent theoretical retailer operating in the Queensland market. The basis of this view is a forecast of the electricity demand in the (forthcoming) tariff year. This forecast of annual demand for electricity is commonly called the load trace and is based on the following factors or inputs:

- (a) a forecast of the total demand for electricity (annual energy);
- (b) a forecast of the summer and winter maximum demand (summer and winter peaks); and
- (c) a load shape generally sourced from the most recent annual period of actual data.

These three elements, illustrated in Figure 3.1 below, form the basis of a load trace forecast. The Authority engaged ACIL to produce the required load traces.

The commonly accepted official forecasts of annual energy and the summer and winter maximum demands are provided to the industry annually by NEMMCO in its *Statement of*

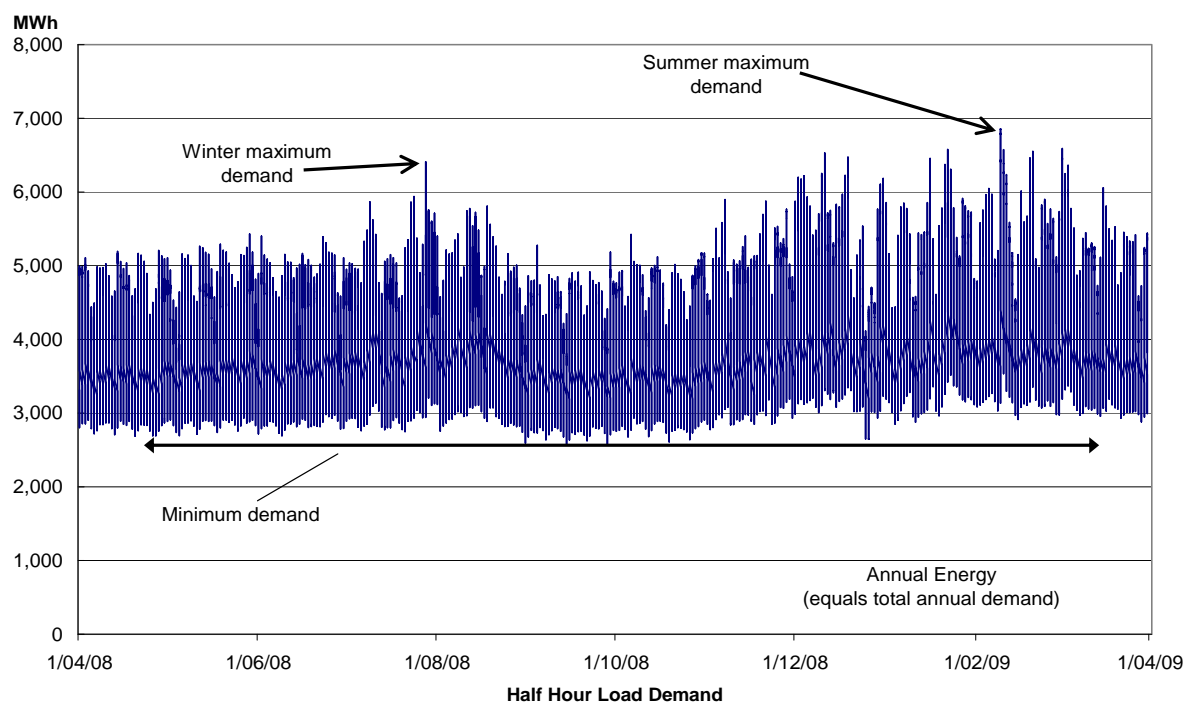
Opportunities (SOO) publication. The most recent SOO was released on 30 October 2008 and remains the current industry forecast of demand in 2009-10.

ACIL also used a related publication, the Powerlink 2008 Annual Planning Report (APR), to derive forecasts of annual energy and summer and winter maximum demand for the 2009-10 tariff year. The current Powerlink APR was released on 27 June 2008.

Although presented in different formats, the SOO and the APR present essentially the same forecasts for electricity demand in Queensland in 2009-10.

The pattern formed by the electricity demand across 17,520 half-hour periods in a year is known as the load shape³. Figure 3.1 shows the load shape for the NEM load using the latest available data from NEMMCO from 1 April 2008 to 31 March 2009. Put simply, to make a forecast of a load trace in some future year requires a forecast of annual energy and the summer and winter maximum demands for that year and a load shape.

Figure 3.1 – NEM Load, June Quarter 2008 – March Quarter 2009



Source: NEMMCO data.

Using the forecast of electricity demand made by ACIL, CRA was engaged to assess the likely cost to a retailer of purchasing that quantum of electricity. In the energy market, a retailer will purchase electricity from a mixture of sources, including contracting directly with generators, bidding in the spot market and through financial derivatives such as swaps, which are designed to manage a retailer's pricing risk. CRA used publicly available data on the spot electricity price and d-cypha⁴ data on the cost of derivative contracts. The risk management process

³ The load *shape* generally refers to actual annual electricity demand whereas the load *trace* generally refers to a forecast of annual electricity demand. In both cases, the terms refer to the pattern formed by the change in half-hourly electricity demand.

⁴ d-cypha Trade provides electricity futures market data to market participants of the Sydney Futures Exchange Energy derivatives market. These data include all of the most commonly traded financial instruments in the NEM.

involves the theoretical retailer building up a portfolio of risk management contracts over a period of two years.

Other Energy Costs

The Authority is also required to take into account general costs associated with supplying electricity to the Queensland market. These other costs relate to compliance with Government environmental schemes, such as the Mandatory Renewable Energy Target and the Queensland Gas Scheme. In addition, there are fees all participants in the National Electricity Market must pay to the market operator which cover NEMMCO's operational expenditure as well as supporting key technical characteristics of the electricity system such as automatic generation control and load shedding.

3.2 Legislative Requirements

The Electricity Act requires that the cost of energy component of the BRCI in a particular year be based on the Authority's view of the likely total cost of purchasing energy to supply the NEM load in that year. In forming this view, the Authority is obliged to take account of its latest estimate of the LRMC of energy in the part of Queensland connected to the national grid and take account of the actual cost of purchasing energy (energy purchase costs) to meet the NEM load in the State in that year.

This view must also take account of the Queensland Gas Scheme under the Electricity Act and the MRET (latterly NRET) scheme under the Commonwealth's *Renewable Energy (Electricity) Act 2000* (the Renewable Energy Act).

The Electricity Act requires that the Authority's estimate of the LRMC of energy 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. The Electricity Regulations state that the method used by the Authority to estimate the LRMC of energy must be a theoretical framework that:

- (a) is generally recognized and understood in economic theory;
- (b) produces a cost of energy in terms of dollars per megawatt hour (\$/MWh);
- (c) calculates the LRMC of energy needed to meet the State NEM load shape for each half hour trading period for the previous calendar year;
- (d) avoids double counting the costs of the Queensland Gas Scheme and the MRET scheme; and
- (e) takes account of ancillary services needed to meet the NEM load of Queensland for the relevant tariff year.

Having established a method for estimating the LRMC of energy for 2008-09, the Authority must continue using this approach unless there are good reasons to change. Section 107(1) of the Electricity Regulation states that the theoretical framework must be the same, or substantially the same, from tariff year to tariff year unless –

- (a) the pricing entity considers that there is a clear reason to change it; and
- (b) the pricing entity has, under section 99, published draft decision material about the reason for the change.

3.3 2009-10 Draft Decision

In its Draft Decision, the Authority considered a number of issues which were raised by stakeholders during the pre-draft consultation processes.

Estimating the LRMC of Energy

The Authority considered two main issues in relation to the LRMC in its Draft Decision:

- (a) had there been a step-change increase in energy generation costs and, if so, how could this be addressed in calculating the LRMC of energy?; and
- (b) should account be taken in 2009-10 of the (likely) introduction of the Carbon Pollution Reduction Scheme (CPRS) in 2010-11?

Step-change increase in energy generation costs

At the time, some retailers argued strongly that the LRMC of energy costs did not take sufficient account of an apparent change in energy generation costs over recent times. Retailers were also of the view that the apparent cost increases constituted a permanent change in costs (a step-change) rather than a temporary shift from a long-run cost path.

In response to this issue, the Authority engaged ACIL to provide it with advice on whether there had been a step-change in energy generation costs and how rising costs might best be reflected in the LRMC of energy calculation. ACIL also updated their 2007 review of capital and fuel costs in the NEM to incorporate recent developments and forecast future energy generation costs based on this update.

In its report, *Fuel and capital costs in the NEM: Greenfield cost data for the calculation of the 2009-10 BRCI* (October 2008), ACIL suggested there had been a step like change in capital costs over the past 24 months – mainly driven by a change in steel prices and, to a lesser extent, labour costs. ACIL concluded that only about half of the cost increases were likely to be permanent and therefore reflect a genuine step-change in costs. ACIL was of the view that the remaining cost increases would most likely unwind to pre-2006-07 levels in the short term as major suppliers increased manufacturing capacity to meet the growing demand.

On this basis, ACIL produced historical trends of median greenfield project capital costs for the following generation technologies:

- (a) supercritical brown and black coal;
- (b) combined and open cycle gas turbines (CCGT and OCGT);
- (c) wind; and
- (d) geothermal.

For completeness and comparison, ACIL's report also included forecasts of costs for each generation type based on a regression analysis, similar to those it had published in previous years.

The results of the two analytical approaches for the two main generation types of interest to the Authority – combined-cycle gas turbine (CCGT) technology and coal-fired technology – are shown in Table 3.1.

Table 3.1 – Forecast costs for CCGT and black coal-fired generation, 2009-10 (\$/KW)

<i>Technology</i>	<i>LRMC</i>		<i>Difference (%)</i>
	<i>Step-change forecast</i>	<i>Regression forecast</i>	
Combined-cycle gas turbine	\$1,314	\$1,214	8.2
Coal-fired (supercritical black coal)	\$2,291	\$2,177	5.3

Source: ACIL Tasman

While the Authority accepted that ACIL’s step-change proposition had some merit, it decided to continue with the regression approach to calculating the LRMC of energy that had been the basis of LRMC estimates in previous BRCI Decisions, but noted that it would consider the step-change issue further before reaching its final decision.

Accounting for CPRS

The second major issue addressed in the Draft Decision was the question of whether the calculation of the 2009-10 BRCI should take account of the likely introduction of the CPRS.

The Authority (along with most other stakeholders) considered that, given there was substantial uncertainty about emissions trading, there was no firm basis for including potential impacts of greenhouse emissions schemes in the 2009-10 BRCI. While the Authority did not include any costs associated with CPRS in its Draft Decision, some scenarios, providing indicative outcomes based on what was known at the time, were provided in attachments to the report in order to stimulate discussion on this issue.

Estimating Energy Purchase Costs

In the Draft Decision, CRA approached estimating the likely costs of purchasing energy by constructing a risk management portfolio appropriate to a prudent theoretical retailer. The risk management strategy involved a mixture of spot purchases and derivative contracts such as swaps and caps, including:

- (a) determining the contract type and volume purchased and the time periods over which these purchases occurred; and
- (b) applying benchmark prices to these purchases.

It was assumed that the representative retailer would spread its purchases for a single year in the future evenly over the preceding two years.

The methodology was not intended to replicate actual purchasing decisions of any particular retailer or actual risk policies that a particular retailer might adopt. CRA considered that its approach was likely to be somewhat conservative and could be expected to result in some over-contracted positions. As actual contract strategy and pricing are confidential, this methodology relied on published contract price data, actual historical pool prices and CRA’s own forecasts of contract and pool prices, as set out in the CRA report (CRA International (2009b)).

The main issues considered in the Draft Decision were:

- (a) NEM load/load shape;
- (b) hedging strategy;
- (c) weighting of price/settlement runs; and
- (d) role and application of Average Loss Factors (ALFs) in the NEM.

Many of these issues were settled following workshops hosted by the Authority focussing on the modelling exercise.

Weighting of the LRMC and the Purchase Cost of Energy

The Authority canvassed the views of stakeholders regarding the weighting that should be given to the LRMC versus purchase costs in arriving at total energy costs.

Views from stakeholders were mixed with a general preference among retailers for a heavier weighting towards energy purchase costs to enable a more rapid pass through of recent increases in purchase costs while the preference among consumer representatives was for a heavier weighting towards LRMC of energy.

In its Draft Decision, the Authority elected to continue with the equal weighting given to both energy costs elements adopted in the 2008-09 BRCI as there were no convincing arguments for change in any particular direction.

Other Energy Costs

In establishing the cost of energy component of the BRCI, the Electricity Act requires the Authority to consider the impact of the Queensland Gas Scheme under the Electricity Act and the MRET scheme established under the Australian Government's *Renewable Energy (Electricity) Act 2000*.

In its Draft Decision, the Authority calculated the costs to retailers of complying with the Queensland Gas Scheme by estimating the penalty price to retailers for not surrendering sufficient Gas Electricity Certificates (GECs) to meet recently revised scheme targets, as the price of GECs has typically traded within a narrow band at or near the penalty price.

Based on this approach, it was estimated that the average cost to a retailer of complying with the scheme was \$2.29/MWh in 2008-09 and \$2.39/MWh in 2009-10. In its Draft Decision, the Authority reported that the total cost of the Queensland Gas Scheme was expected to increase from \$84 million in 2008-09 to \$87 million in 2009-10, an increase of 3.6%.

The State based MRET schemes are to be combined into a national scheme (the National Renewable Energy Target (NRET)) which is set at 20% of electricity consumption by 2020. For the purposes of calculating the contribution of NRET to energy costs, CRA adopted the same methodology in the Draft Decision as it had used in previous years based on weekly market prices for Renewable Energy Certificates (RECs) published by the Australian Financial Markets Association (AFMA).

Using this approach, it was estimated that the allowance for complying with the NRET scheme increased from \$1.35/MWh in 2008-09 to \$1.91/MWh in 2009-10, resulting in around a 40% increase from \$50 million in 2008-09 to \$70 million in 2009-10. This significant increase was driven by an estimated ramp-up in the required proportion of renewable energy purchased from

3.59% in 2009 to 3.72% in 2010 and an increase in the forecast average REC price from \$45.85 in 2009 to \$58.32 in 2010.

To determine the costs to retailers associated with paying participant fees to NEMMCO, CRA cited fees of \$0.32/MWh in 2008-09 from the latest published NEMMCO Schedule of Fees and estimated fees of \$0.31/MWh in 2009-10 based on trends over the period 2004-05 to 2008-09. On this basis, the Authority expected the cost of NEM fees, once growth in retail activity was accounted for, to decline slightly from \$12 million in 2008-09 to \$11 million in 2009-10.

To estimate the costs to retailers associated with ancillary services provided by NEMMCO, CRA averaged the most recent 52 weeks ancillary services costs data. The Authority accepted the CRA estimate that ancillary services costs would decrease from \$0.39/MWh in 2008-09 to \$0.37/MWh in 2009-10. In dollar terms, this equated to an expected fall of almost 7% from \$14.5 million to \$13.5 million in 2009-10.

Draft Decision on cost of energy

In its Draft Decision, the Authority estimated that the total cost of energy would rise from \$1,930 million in 2008-09 to \$2,199 million 2009-10, an increase of 14% as shown in Table 3.2.

Table 3.2 – Cost-of-energy Components, 2009-10 Draft Decision

<i>Cost Component</i>	<i>2008-09</i>		<i>2009-10</i>		<i>% change</i>
		<i>\$MWh</i>		<i>\$MWh</i>	
LRMC of energy - 50% weighting	42.61	21.31	53.42	26.71	25
Energy purchase costs - 50% weighting	52.91	26.46	57.34	28.67	8
Weighted average of LRMC and purchase costs		47.76		55.38	16
20% NRET		1.35		1.91	41
13% gas scheme		2.29		2.39	4
NEM fees		0.32		0.31	-4
Ancillary services		0.39		0.37	-3
Total:	\$/MWh	52.11	60.36	16	
	\$m	1,930	2,199	14	

Source: QCA: Draft Decision: Benchmark Retail Cost Index for Electricity 2009-10

Submissions in Response to the Draft Decision

LRMC of Energy

AGL (2008e), Origin Energy (2008e) and TRUenergy (2008e) maintained that the Authority should adopt a step-change approach to calculating the LRMC of energy. However, they also noted that, if a trend analysis was used by the Authority, the length of the time series used should be shortened from 15 years to between three to five years (AGL) and 10 years (TRUenergy).

In contrast, QCOSS (2008b) and the Queensland Consumers Association (2008b) were of the view that the approach used by the Authority in its draft decision should not be changed.

Origin Energy (2008e) advised the Authority that it would need to carefully consider how it treated the issues of CPRS and increases in MRET in future BRCI calculations if it continued to use a regression analysis approach.

AGL (2008e) noted that an inflation rate of 2.5% was used in the calculation of the Weighted Average Cost of Capital (WACC), whereas a rate of 3% was used in the rest of the analysis. AGL also noted that, given the current situation in financial markets, it believed the debt premium and risk premium to be understated and the risk free rate overstated.

Energy Purchase Costs

Origin Energy (2008e) and AGL (2008e) both raised the issue of the application of loss factors in determining the hedged load, stating that the application of loss factors prior to the theoretical acquisition of hedges was more reflective of the approach currently taken by retailers.

Origin Energy (2008e) also expressed concern at loss factors of less than one being used in calculating hedge positions and claimed that the change from using average loss factors to marginal loss factors represented a change of methodology.

Other Costs of Energy

AGL (2008e) and Origin Energy (2008e) highlighted that draft legislation for the NRET scheme confirmed that the NRET target would be 12.5TWh in 2010 and that this figure should be used in calculating costs associated with the MRET scheme.

In addition, Origin Energy (2008e) noted that legislation had been passed increasing the Queensland Gas Scheme target rate from 13% to 15% for the 2010 calendar year.

Submissions following the New Certificate of Delegation

AGL (2009f) reiterated its view about the loads which the Authority should take into account when calculating the cost of energy components of the BRCI as well as its concern that detailed load data was not provided to stakeholders for consideration.

Origin (2009f) highlighted a number of areas of the BRCI which it considered should be updated in light of the extension granted by the Minister. These included the input costs and WACC used in the LRMC, February 2009 pool price data and certain forecasts which affect retail costs.

3.4 Effect of the Judicial Review of the 2008-09 BRCI Final Decision on the 2009-10 Cost of Energy

The judgement on the judicial review application determined that the energy purchase costs of supplying the NEM load as defined under the Act (NEM load) must be estimated based on the load profile of the NEM load rather than on the load profile of the total State NEM load (State NEM load) as had been done previously.

Therefore, the Authority has remade its 2008-09 Decision basing the calculation of energy purchase costs on the load profile of the NEM load. Similarly, the calculation of energy purchase costs in this 2009-10 Final Decision have been based on the same method as used in the Remade Decision and is different to that used in the Draft Decision.

3.5 NEM Load Consultation Paper

On 8 May 2009, following receipt of the judgment, the Authority released a Consultation Paper proposing an alternative method (from that used in the 2009-10 Draft Decision) for constructing the forecast NEM load to be used in calculating energy purchase costs. The Authority also released a paper prepared by ACIL Tasman on this issue.

The Authority received four submissions in response to the Consultation Paper. In addition, AGL and Origin Energy made further comment on the proposed approach in other correspondence.

Submissions in response to the Consultation Paper

Queensland Consumers Association submission

In its submission, the Queensland Consumers Association expressed its general concern that the current methodology for estimating the BRCI is not consistent with achieving price adjustments and price levels that are accurate and equitable between consumers and industry over time. The Association was of the view that a broad, independent review of the BRCI concept and the legislation and of alternative approaches to the adjustment of or setting of regulated electricity prices was required. The Association agreed that, given the Supreme Court's decision, the Authority appeared to have no alternative but to adopt the approach outlined in the Consultation Paper.

Integral Energy submission

Integral Energy expressed concern about the absence of data and an explanation by the Authority of the range of adjustments that are proposed to be made to the BRCI's calculation which made it difficult for interested parties to consider and then respond to the Authority on whether the final approach will achieve the BRCI's stated objectives. While Integral Energy acknowledged the time limitations placed on the Authority by the Minister and the judgment, it questioned why alternative scenario and data sets were not prepared in anticipation of the Supreme Court's decision. Integral Energy also suggested that the Authority release, as a matter of urgency, a comparative table identifying the anticipated impact of the data and methodological changes that it proposes to make between the Draft and Final Decision.

The Authority notes that the Consultation Paper raised issues of principle in relation to the construction of a NEM load trace and, as such, did not include examples of the outcome of applying the proposed method.

Origin Energy submission

Origin Energy questioned why the Authority had moved away from CRA's methodology for calculating the NEM load that was outlined in its (CRA's) Final 2008-09 Addendum Report of 26 May 2008. Origin Energy suggested further investigation should be undertaken of the problems identified with the CRA approach before a new approach to forecasting load traces was introduced.

Origin Energy disputed CRA's conclusion reported in the Consultation Paper that estimating the small load in isolation from the total load was not appropriate, despite acknowledging that the Authority, CRA and ACIL have all suggested that the CRA forecast NEM load trace is unsuitable for use in the 2009-10 BRCI.

Despite the problems identified in the Consultation Paper, Origin Energy did not support moving to the ACIL method because it was concerned that the alternatives must be able to be tested to ensure that in solving one problem (which it believed may or may not be a problem) new issues that effectively distort the shape of the load trace are not introduced.

Origin also raised several technical issues in relation to the ACIL method for forecasting the 2009-10 load trace including the load shape (summer and winter maximum demands), splicing quarters of actual data to fit the financial year configuration of the load trace forecast and weather normalisation. ACIL has responded to these technical matters in its Final Report which will be released at the same time as this Final Decision.

AGL submission(s)

In its submission(s) in response to the Consultation Paper, AGL provided detailed guidance to the Authority on the properties it expected an acceptable NEM load trace to exhibit. Much of the comment provided by AGL was technical in nature and ACIL has considered this in preparing its Final Report.

AGL's principal concern, based largely upon the load traces produced by ACIL which the Authority had provided for AGL to review and provide feedback on, was the load factors that might be evident in the (ACIL) load traces and how closely these might correspond to the load factors implied by the official SOO forecasts.

AGL also raised its concerns about the corresponding spot price traces and its belief that ACIL had suggested these would need to be redone based on the NEM load. This was incorrect and there was no suggestion in the consultation about changing the manner in which prices were to be determined.

AGL provided a second submission to the Authority prepared by its consultant Creative Energy Solutions (CES). Again, the CES report was largely commenting on technical aspects of the load traces AGL had received rather than on matters raised in the Consultation Paper. These technical issues have been addressed in ACIL's Final Report.

3.6 The Authority's Final Decision

Long Run Marginal Cost of Energy

In its Draft Decision, the Authority undertook to consider further the issue of whether or not there had been a step-change in capital and fuel input costs before making its final decision. The issue is significant because, if there has been a permanent lift in the prices of capital and fuel costs, as ACIL had advised in October 2008, then a regression-based approach to forecasting LRMC input costs may not be the most appropriate as it will tend to flatten out the cost increases and delay the rate at which they brought to account in the LRMC estimates.

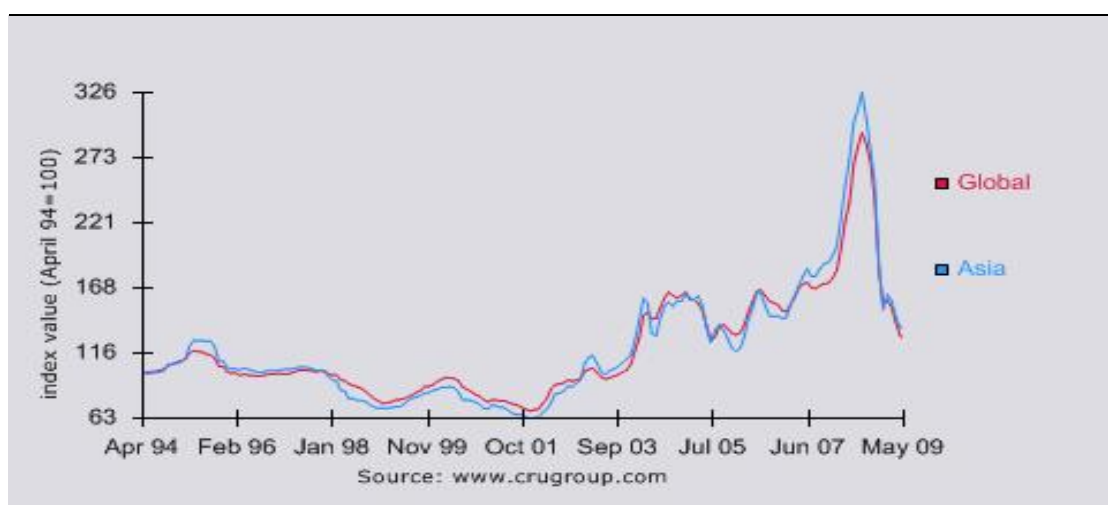
To consider this matter further and also in response to the comments by the Minister in his letter accompanying the new Delegation regarding the use of the most reliable data in the face of the changing economic conditions, the Authority engaged Concept Economics to provide an independent review of ACIL's earlier LRMC input cost forecasts and to also consider how the rapidly changing global economic environment might impact on the assessment of the step-change claims made by the retailers.

Concept Economics: Review of the ACIL Tasman approach to estimating capital costs

In its Final Report, Review of Inputs to Cost Modelling of the NEM (14 May 2009), Concept Economics notes that ACIL's proposition that a step-change in capital cost had occurred was driven mainly by a change in steel prices and, to a lesser extent, labour. While Concept Economics accepted that steel prices rose steeply over the two or three years prior to October 2008 and that capital costs appeared to increase concurrently, these prices have dropped substantially since that time.

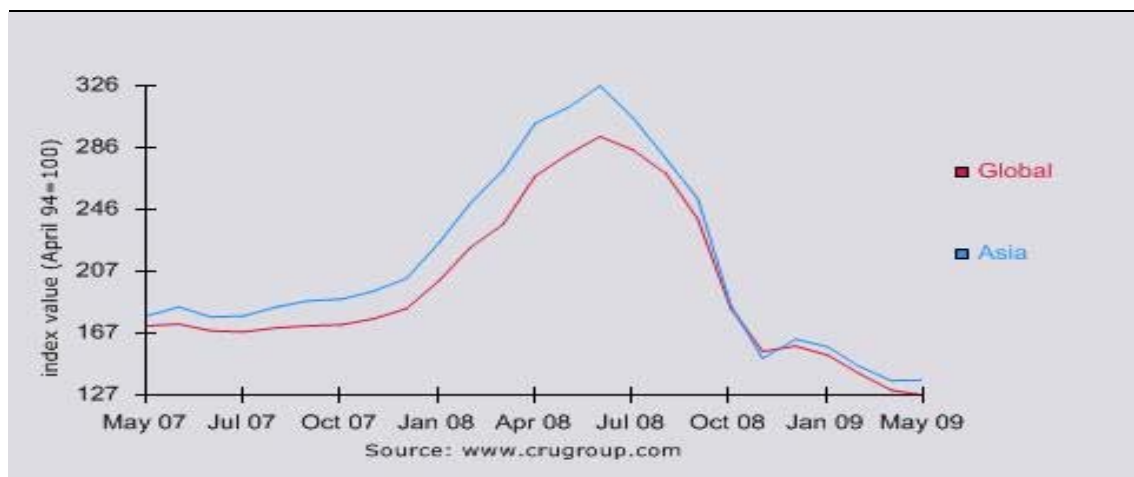
Concept Economics reviewed the CRU Steel price index which ACIL used as a measure of steel price changes in its October 2008 report. Based on this index, steel prices steadily declined from 1994 to 2001 but then began to rise until late 2007. Between December 2007 and the middle of 2008, steel prices roughly doubled but then fell precipitously from mid-2008 to be at pre-2007 levels by the end of that year (see Figure 3.2).

Figure 3.2 – CRU Steel price index from April 1994- May 2009 (April 1994=100)



Source: CRU (2009), accessed at www.cruonline.crugroup.com

Figure 3.3 provides a more graphic illustration of the rise and fall in steel prices over the past two years, from May 2007 to May 2009. The CRU Steel index has more than halved from its peak of 286 in June 2008 to 127 in May 2009, a decline of 55.6%. Concept Economics cites a similar decline of 58.3% in the Asian Steel Price Index, which fell from its high of 326 in June 2008 to 136 in May 2009.

Figure 3.3 – CRU Steel price index from May 2007-May 2009 (April 1994=100)

Source: CRU (2009), accessed at www.cruonline.crugroup.com

That said, Concept Economics did find that statistical tests based on historical data from 1997 to October 2008 (which was the latest available to ACIL at the time) did support the hypothesis of a structural break in the data series for CCGT. However, for coal, the results were inconclusive.

Concept Economics also had some concerns about the selection of data used by ACIL. Concept Economics noted that, because ACIL did not consider that a regression approach for forecasting the LRMC was appropriate (because of the apparent step-change in costs), ACIL instead projected capital costs by combining steel and labour price indexes and aligning this new index to capital cost indexes for CCGT and Black Coal plants.

Concept Economics estimates of capital costs

In order to overcome the issues it had identified, Concept Economics developed its own method of projecting power plant capital costs. This was a combination of the original regression approach adopted for previous BRCI Decisions and ACIL's approach of decomposing capital cost movements into their component parts. In essence, Concept Economics constructed an historical fixed weight index of power plant capital costs from freely available and easily updated data which is then projected into the future

Concept Economics based its capital cost index on four variables:

- (a) a producer price index (PPI) for basic metals which is intended to account for movements in steel and non-ferrous metals prices used in the construction of power plants (ABS cat. no. 6427.0);
- (b) a PPI for cement (ABS cat. no. 6427.0);
- (c) a price index for imported materials (ABS cat. no. 6427.0) that is intended to account for movements in the Australian dollar price of imported components, which would typically be the generating equipment itself; and
- (d) an index of average weekly earnings of workers in the construction industry (derived from ABS cat. no. 6302.0).

Concept determined the fixed weights for each input as outlined in Table 3.3.

Table 3.3 – Assumed capital cost weighting in 2007-08, by technology

<i>Factor</i>	<i>Black Coal</i>	<i>Brown Coal</i>	<i>CCGT</i>	<i>OCGT</i>	<i>Wind</i>	<i>Geothermal</i>	<i>Biomass</i>
	%	%	%	%	%	%	%
Labour	30.0	30.0	32.5	31.5	7.5	30.0	30.0
Cement	7.5	7.5	6.9	7.1	7.5	10.0	7.5
Imported materials	40.0	40.0	40.0	40.0	85.0	40.0	40.0
Basic Metal	22.5	22.5	20.6	21.4	0.0	20.0	22.5
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0

Data source: Concept Economics' Review of Inputs to Cost Modelling of the NEM (May 2009, p.9). CCGT – Combined Cycle Gas Turbine. OCGT – Open Cycle Gas Turbine.

The second step to Concept Economics forecasting approach was to fit a regression line to the historical index series (covering slightly more than 15 years, which Concept Economics considered an appropriate data period upon which to base its regression analysis) and then use that fitted line to project costs forward until 2018.

Concept Economics' calculation of capital costs for the LRMC using its indexing/regression approach are provided in Table 3.4.

Table 3.4 – Concept Economics, capital cost by technology: 2008-2018

	<i>CCGT</i>	<i>OCGT</i>	<i>Black Coal</i>	<i>Brown Coal</i>	<i>Wind</i>	<i>Geothermal</i>
2008	\$1,200	\$900	\$2,200	\$2,420	\$2,300	\$5,000
2009	\$1,212	\$909	\$2,221	\$2,444	\$2,369	\$5,061
2010	\$1,202	\$902	\$2,209	\$2,424	\$2,323	\$5,022
2011	\$1,227	\$920	\$2,249	\$2,473	\$2,345	\$5,125
2012	\$1,254	\$940	\$2,298	\$2,527	\$2,369	\$5,235
2013	\$1,281	\$961	\$2,348	\$2,582	\$2,393	\$5,348
2014	\$1,309	\$982	\$2,399	\$2,639	\$2,418	\$5,462
2015	\$1,338	\$1,003	\$2,451	\$2,696	\$2,443	\$5,580
2016	\$1,367	\$1,025	\$2,505	\$2,755	\$2,468	\$5,699
2017	\$1,397	\$1,047	\$2,559	\$2,815	\$2,493	\$5,822
2018	\$1,427	\$1,070	\$2,615	\$2,877	\$2,519	\$5,947

Source: Concept Economics' Review of Inputs to Cost Modelling of the NEM (May 2009), compilation of Tables 2-6.

These can be compared to ACIL's earlier calculations of capital costs for the LRMC, reproduced in Table 3.5:

Table 3.5 – ACIL’s calculation of capital cost by technology: 2008-2018

	<i>CCGT</i>	<i>OCGT</i>	<i>Black Coal</i>	<i>Brown Coal</i>	<i>Wind</i>	<i>Geothermal</i>
2008	\$1,200	\$900	\$2,200	\$2,420	\$2,300	\$5,000
2009	\$1,404	\$1,053	\$2,330	\$2,563	\$2,646	\$5,163
2010	\$1,314	\$985	\$2,291	\$2,520	\$2,525	\$5,330
2011	\$1,255	\$941	\$2,268	\$2,495	\$2,406	\$5,504
2012	\$1,284	\$963	\$2,284	\$2,512	\$2,415	\$5,569
2013	\$1,292	\$969	\$2,301	\$2,531	\$2,394	\$5,635
2014	\$1,308	\$981	\$2,344	\$2,578	\$2,450	\$5,701
2015	\$1,336	\$1,002	\$2,387	\$2,626	\$2,504	\$5,769
2016	\$1,365	\$1,024	\$2,444	\$2,688	\$2,557	\$5,837
2017	\$1,395	\$1,046	\$2,501	\$2,751	\$2,608	\$5,907
2018	\$1,424	\$1,068	\$2,559	\$2,815	\$2,658	\$5,977

Source: ACIL Tasman’s Fuel and capital costs in the NEM: Greenfield cost data for the calculation of the 2009-10 BRCI (October 2008), compilation of Tables 16, 19, 21, 25, 30 and 32.

While Concept Economics’ approach to calculating capital costs differs somewhat from the approach used by ACIL, the resulting capital cost forecasts are not substantially different over the long run.

Concept Economics other input costs

Concept Economics also provided the Authority with updated fuel input costs and an assessment on ACIL Tasman’s approach to a number of other LRMC inputs.

In relation to fuel prices, Concept Economics provided the Authority with estimates of world energy prices (oil, gas and coal), projected nominal and real gas prices (by Australian regions) and projected nominal and real coal prices (by Australian region).

Tables 3.6 and 3.7 below show the ACIL projections from the time of the Draft Decision and the more recent Concept Economics projections. However, the tables are not directly comparable because the regional basis for the projections is different.

Concept Economics adopted base year coal prices from ACIL (2007) but developed its own forward prices from that starting point.

Table 3.6 – ACIL – Projected coal prices by region – Draft Decision

Area	Deposit	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	Approximate potential MW supported
North Qld	Pentland	\$1.73	\$1.73	\$1.73	\$1.73	\$1.73	\$1.73	\$1.73	\$1.73	\$1.73	4000
Central Qld	Alpha	\$1.14	\$1.14	\$1.14	\$1.14	\$1.14	\$1.14	\$1.13	\$1.13	\$1.13	6000
	Kevins Comer	\$1.29	\$1.29	\$1.29	\$1.29	\$1.29	\$1.29	\$1.28	\$1.28	\$1.28	7000
South West Qld	Felton	\$1.22	\$1.22	\$1.22	\$1.22	\$1.22	\$1.22	\$1.22	\$1.22	\$1.22	5000
	Existing mines Surat	\$0.93	\$0.87	\$0.87	\$0.87	\$0.87	\$0.87	\$0.87	\$0.87	\$0.87	7000
	Horse Creek	\$1.06	\$1.06	\$1.06	\$1.06	\$1.06	\$1.06	\$1.06	\$1.06	\$1.06	1000
	Wandoan	\$1.48	\$1.48	\$1.48	\$1.48	\$1.48	\$1.48	\$1.48	\$1.48	\$1.48	9000
North NSW	Maules Creek	\$1.27	\$1.19	\$1.14	\$1.09	\$1.06	\$1.02	\$0.99	\$0.95	\$0.92	3000
	Boggabri	\$1.31	\$1.23	\$1.18	\$1.13	\$1.10	\$1.06	\$1.03	\$0.99	\$0.96	3000
	Caroona	\$1.34	\$1.26	\$1.21	\$1.16	\$1.13	\$1.09	\$1.06	\$1.02	\$0.99	4000
	Narabri	\$1.22	\$1.14	\$1.09	\$1.04	\$1.01	\$0.97	\$0.97	\$0.97	\$0.97	6000
Central NSW	Moorlaben	\$1.29	\$1.22	\$1.17	\$1.12	\$1.09	\$1.05	\$1.02	\$0.99	\$0.96	1000
	Ulan	\$1.27	\$1.19	\$1.14	\$1.10	\$1.06	\$1.03	\$1.00	\$0.96	\$0.93	4000
South West NSW	Oaklands	\$1.00	\$1.00	\$1.00	\$1.00	\$1.00	\$1.00	\$1.00	\$1.00	\$1.00	5000
Victoria	Latrobe Valley	\$0.57	\$0.57	\$0.57	\$0.57	\$0.57	\$0.56	\$0.56	\$0.56	\$0.56	>10000

Source: ACIL Tasman's Fuel and capital costs in the NEM: Greenfield cost data for the calculation of the 2009-10 BRCI (October 2008, Table 50, p.95).

Table 3.7 – Concept Economics – Projected coal prices by region – Final Decision

	QLD		NSW		VIC	
	A\$/GJ	A\$/GJ	A\$/GJ	A\$/GJ	A\$/GJ	A\$/GJ
	Nominal	\$2009-10	Nominal	\$2009-10	Nominal	\$2009-10
2009-10	1.244	1.244	1.465	1.465	0.595	0.595
2010-11	1.340	1.307	1.578	1.538	0.610	0.595
2011-12	1.389	1.320	1.635	1.553	0.626	0.595
2012-13	1.431	1.326	1.684	1.560	0.642	0.595
2013-14	1.472	1.330	1.733	1.565	0.659	0.595
2014-15	1.518	1.336	1.787	1.573	0.676	0.595
2015-16	1.562	1.340	1.838	1.577	0.693	0.595
2016-17	1.606	1.344	1.891	1.581	0.711	0.595
2017-18	1.653	1.347	1.945	1.586	0.729	0.595

Source: Concept Economics' Review of Inputs to Cost Modelling of the NEM (May 2009, Table 10, p.25).

In relation to the other LRMC inputs such as the WACC, plant auxiliaries, thermal efficiency and operating and maintenance costs, Concept Economics has, for the most part, adopted exactly the same parameters as ACIL used.

Clearly, there has been a major turn around in the supply and demand balance affecting electricity generation input costs. While ACIL speculated that supply would catch up to demand as manufacturers expanded production to meet the rising demand, and hence prices would begin to decline, the reverse has occurred and much of the demand has evaporated and supply is probably now in excess. Either way, the outcome is much the same as far as input costs are concerned. The rapid rise in cost has been followed by an equally dramatic fall.

The evidence now suggests that there was a significant spike in electricity generation capital costs during 2007 and 2008 but that this rapid run-up in costs was, in the end, not permanent.

Compared to ACIL, Concept Economics has had the benefit of being able to observe the later events. The Concept Economics input cost estimates are therefore more in keeping with current economic conditions and offer a more appropriate (but not substantially different) basis for assessing the LRMC of energy.

CRA has updated its estimate of LRMC for 2009-10 to reflect this later data.

The introduction of the CPRS?

In its Draft Decision, the Authority decided not to include any costs associated with the future introduction of a carbon pollution reduction scheme due to the uncertainty surrounding the timing of introduction of the scheme as well as the detail of the scheme itself. The Commonwealth Government has since delayed the introduction of the CPRS until 2011 and flagged other changes to ameliorate its impact. These decisions serve to reinforce the Authority's view to exclude any costs associated with CPRS at this time.

Energy Purchase Costs

As noted in Chapter 2, the judgment in the judicial review application found that the Authority had erred in using the load profile of the State NEM load as the basis for estimating energy purchase costs in its 2008-09 Decision and that it should instead use the profile of the NEM load. The same method (which is different to that used in the Draft Decision) must also be followed in estimating energy purchase costs for 2009-10.

As the Authority noted in its 8 May 2009 Consultation Paper, the first step in achieving that objective is to construct a forecast 2009-10 NEM load trace. The method used by CRA to produce a load trace for the NEM load calculations in its 26 May 2008 Addendum Report was found to be flawed when an attempt was made to calculate energy purchase costs for 2009-10 using the identical method. It is therefore not appropriate to use the numbers CRA previously calculated.

In its Consultation Paper, the Authority proposed adopting a method recommended by ACIL for constructing a forecast NEM load trace. The approach proposed by ACIL was the same as it had outlined to the Court as the Authority's expert witness in the judicial review hearing.

Simply put, ACIL forecast the total State NEM load and the load of directly connected customers separately and then deduct the directly connected customer load from the total State NEM load to determine the NEM load. On the other hand, CRA attempted to estimate the NEM load directly.

While there were many comments from stakeholders in response to ACIL's method, the majority of these comments concerned technical issues which might attend any proposed approach. There was no suggestion the ACIL method was deficient in any respect or that the technical comments indicated the approach itself was flawed but rather that it was different and therefore a somewhat unknown quantity as far as the results it might produce were concerned.

ACIL has considered all the technical issues raised in submissions in preparing its Final Report. Having had regard to ACIL's advice on these issues, the Authority is satisfied that ACIL's approach is an appropriate basis for determining the NEM load trace.

Accordingly, the Authority has decided to use the ACIL method to construct the required NEM load trace for 2009-10. This will mean the method of constructing this NEM load trace is consistent with that used in the Authority's remade 2008-09 Decision.

The Authority released the 2007-08, 2008-09 and 2009-10 ACIL NEM load traces (prepared on the basis of information that would have been known at the time of the respective decisions as required by the judgement) on 19 May 2009 for the information of stakeholders.

The Authority noted in its Consultation Paper that existing load forecasts from NEMMCO and Powerlink pre-dated the severe downturn in economic activity in the last six months but there appeared to be no alternative source that would provide more up to date and universally acceptable forecasts. Comments in submissions on the Consultation Paper did not suggest any alternatives. New official forecasts will not be available until later this year.

ACIL's forecast load traces are therefore based on forecasts of summer and winter peak demand and annual energy delivered from the transmission network as published by Powerlink in its 2008 Annual Planning Report (which were released in June 2008 and are consistent with the 2008 NEMMCO SOO forecasts of scheduled generated summer and winter peak demand and scheduled sent out annual energy) and the latest NEMMCO half-hourly load data for each Queensland TNI up to 31 March 2009.

The Authority also requested ACIL provide consistent load trace forecasts for each of the regions in the NEM for the years 2007-08, 2008-09 and 2009-10 at 10, 50 and 90POE for use by CRA in calculating the NEM spot prices which is a key input into the calculation of energy purchase costs.

Using the ACIL load forecasts, CRA has applied the same methodology used in previous years and as used in the Draft Decision to estimate the costs of purchasing energy by constructing a risk management portfolio based on a mixture of spot purchases and derivative contracts such as swaps and caps, including determining the contract type and volume purchased and the time periods over which these purchases occurred and then applying benchmark prices to these purchases.

The CRA methodology from this point on was the subject of considerable scrutiny at the workshops conducted early in this process and has not changed other than for the use of the ACIL NEM load traces in determining quantities of energy to be purchased.

To recognise the uncertain nature of demand, CRA applied a probabilistic approach to determining the load trace upon which purchasing decisions are based. CRA's energy purchase cost pricing calculations are based on the weights that NEMMCO applies in its SOO/ANTS modelling, as follows:

- (a) medium economic growth 10POE load – weighted 30%;
- (b) medium economic growth 50POE load – weighted 40%; and

- (c) medium economic growth 90POE load – weighted 30%.

In relation to determining the spot price in the wholesale energy market that underpins the calculations of derivative contracts, CRA derive this price from modelling the national NEM based on the forecast load traces of each jurisdiction's total State NEM load.

Further discussion of CRA's approach to forecasting energy purchase costs is contained in its Final Report (CRA, 2009b).

The Authority is of the view that this approach to calculating energy purchase costs is consistent with the judgement in respect of the judicial review of the 2008-09 BRCI Decision and the approach adopted in the Authority's re-made 2008-09 Decision. The Authority has therefore continued with this approach calculate energy purchase costs for 2009-10.

In doing so, however, it accepts that the estimates used are now considerably out of date because they do not factor in the recent economic downturn. However, in the absence of any other acceptable load forecasts, they remain the most appropriate basis for calculating the cost of energy.

Time did not permit the Authority to consult on the price traces developed by CRA. In this regard, the Authority notes that neither the Act nor the Regulations require the Authority to make either price or load trace information available although it has done so in the past, when time permitted. The Authority has, however, consulted on the methodology it proposed to use.

The unit costs of purchasing energy that result from using the ACIL load traces differ from those used in the Draft Decision, as shown in Table 3.7:

Table 3.7: Energy Purchase Costs 2008-09 and 2009-10 (\$/MWh)

	Draft Decision 2009-10 (CRA Load Traces)			Final Decision 2009-10 (ACIL Load Traces)		
	2008-09	2009-10	% Change	2008-09	2009-10	% Change
Total State NEM Load (as per Draft Decision)	52.91	57.34	8.36%	56.94	56.06	-1.55%
NEM Load as defined in Act (as required by judgement)	61.53	na	na	58.00	57.70	-0.52%

In this regard, the Authority notes that:

- (a) the increase in energy purchase costs is now based on the NEM load and not the State NEM load; and
- (b) the period on which the respective 2009-10 forecasts are based are considerably different, with there being little overlap between them. In this regard, CRA used actual data for the 12 months up to 30 June 2008 to base its forecast 2009-10 load on while ACIL has used actual data up to 31 March 2009 to base its forecast load on.

Other Energy Costs

In establishing the cost-of-energy component of the BRCI, the Electricity Act requires the Authority to consider the impact of the Queensland Gas Scheme under the Electricity Act and the MRET scheme established under the Renewable Energy (Electricity) Act 2000. For this Final Decision, CRA has updated the other energy costs for 2009-10 to reflect the more recent

information currently available. In all other respects, these costs are unchanged from the Draft Decision.

The Queensland Gas Scheme

The costs to retailers of complying with the Queensland Gas Scheme are based on the penalty price to retailers for not surrendering sufficient Gas Electricity Certificates (GECs). Based on current data, the cost for 2009-10 is estimated to be \$2.56/MWh or, in total, \$94 million, an increase of 11.2% from 2008-09.

National Renewable Energy Target (NRET)

Submissions in response to the Draft Decision and Consultation Paper expressed concern that the updated NRET target of 12,500MWh was not being used in modelling for the purposes of the 2009-10 BRCI. This is not the case and the expanded target is being used in the energy cost calculations. However, it should be noted that the NRET target is imposed on a calendar year basis while the BRCI is calculated on a financial year basis. As a result, the appropriate NRET target will incorporate six months of the 2009 target and six months of the 2010 target. This is the target used in calculation of NRET compliance costs.

To determine the costs to retailers of complying with the NRET scheme, weekly market prices for RECs published by the Australian Financial Markets Association (AFMA) were used. Based on this approach and the currently available data, the cost of complying with the NRET scheme is estimated to be \$2.43/MWh in 2009-10 and in total \$89.5 million, an increase of 79% from 2008-09. This significant cost increase is related to the new higher NRET target in 2009-10.

NEM participant fees and ancillary services

As it did in the Draft Decision, the Authority has also taken into account NEM participant fees and ancillary services charges paid by retailers. These fees and charges cover NEMMCO operational expenditure as well as supporting key technical characteristics of the electricity system such as automatic generation control and load shedding.

For 2009-10, CRA has estimated the cost of NEMMCO participant fees to be \$0.33/MWh based on trends over the period 2004-05 to 2008-09 and including the currently available data. On this basis, the Authority expects the total cost of NEM fees, once growth in retail activity is accounted for, to be \$12.2 million in 2009-10, a slight increase from 2008-09.

The cost of ancillary services provided by NEMMCO has been updated from the Draft Decision to by including currently available data. Based on the average cost over the preceding 52 weeks of ancillary services costs data, it is estimated that the cost of ancillary services will be \$0.40 in 2009-10, or in total \$14.7 million, an increase of around 2% from 2008-09.

3.7 Total Cost of Energy

In total, the Authority estimates that the total cost of energy will rise from \$2,025 million in 2008-09 to \$2,255 million 2009-10, an increase of 11.4%. In terms of \$/MWh, the total cost of energy is expected to increase from \$54.66 in 2008-09 to \$61.20 in 2009-10.

Table 3.8 – Cost of energy components, 2008-09 to 2009-10

<i>Cost Component</i>	<i>2008-09</i>		<i>2009-10</i>		<i>% change</i>
	<i>\$MWh</i>	<i>\$MWh</i>	<i>\$MWh</i>	<i>\$MWh</i>	
<i>LRMC of energy (50% weighting)</i>	42.61	21.31	53.28	26.64	25.04
<i>Energy purchase costs (50% weighting)</i>	58.00	29.00	57.70	28.85	-0.52
Cost of Energy (Weighted average of LRMC and EPC)		50.31		55.49	10.31
20% NRET		1.35		2.43	79.84
Queensland Gas Scheme		2.29		2.56	11.47
NEM fees		0.32		0.33	0.83
Ancillary services		0.39		0.40	4.64
Total: \$/MWh		54.66		61.20	11.98
\$m		2,024.5		2,255.4	11.40

Data sources: CRA and Concept Economics modelling.

4. NETWORK COSTS

In accordance with the provisions of the Electricity Act, the network cost component of the BRCI is based on the Authority's view of the revenue requirements of distribution and transmission network service providers in Queensland.

In calculating distribution network costs for 2009-10, the Authority has included adjustments made to the distribution revenue requirements for Energex and Ergon Energy since the release of its 2005 Final Determination. These adjustments reflect changes made as a result of several cost pass-through decisions and the removal of non-distribution use of system (non-DUOS) services from the revenue cap form of regulation.

The Authority has also updated its estimate of transmission costs to reflect the latest Powerlink and other transmission-related charges that the distributors are expected to pass through to customers in 2009-10.

On this basis, the Authority estimates the relevant network costs to be \$2,131 million in 2008 09 and \$2,382 million in 2009-10, an increase of 11.8%.

4.1 Background

The transportation of electricity from generators to consumers requires the use of both the transmission network and the distribution networks. The transmission network transports electricity at high voltages across the State (and from interstate) while the distribution networks distribute electricity at lower voltages from transmission connection points to households, small businesses and large industrial users.

The cost of using the transmission and distribution networks typically accounts for around 50% of the total cost of providing electricity to households. The network share of total electricity costs for larger customers can vary significantly depending on the pattern of their electricity use and their location.

Transmission costs are the amount that Queensland's transmission entity (Powerlink) charges Queensland's two electricity distributors (Energex and Ergon Energy) for using its transmission network. While Powerlink's Transmission Use of System (TUOS) charges are by far the largest component of transmission costs, there are a number of other transmission-related costs incurred by distributors. These include avoided TUOS payments made to embedded generators and payments to other distribution network service providers for (transmission like) network services.

Distribution costs are based on the Annual Aggregate Revenue Requirements (AARRs) which were originally set out for both Energex and Ergon Energy in the Authority's *Final Determination: Regulation of Electricity Distribution* (April 2005). Since that time, the AARRs have been amended to reflect a number of adjustments made by the Authority including several cost pass-through decisions and adjustments to account for the exclusion of non-DUOS services from the distributors' revenue caps.

Further details on the Authority's original determination of network costs and subsequent adjustments can be found in the following publications:

- Final Determination: Regulation of Electricity Distribution (April 2005)

<http://www.qca.org.au/files/ACF14.pdf>

- Final Decision: Energex Application for Capital Expenditure Cost Pass-through (March 2007)
http://www.qca.org.au/files/E-EnergexCAPEX_cost_pass_through_Final_Decision.pdf
- Final Decision: Electricity Distribution: Review of Excluded Distribution Services (December 2007)
<http://www.qca.org.au/files/E-ExcludeDistService-QCA-FinalDecisionDec07.pdf>
- Final Decision: Ergon Energy's cost pass-through application for Cyclone Larry (September 2008 – As amended in April 2009)
<http://www.qca.org.au/files/E-CPT-QCA-TropCycLar-0409.pdf>
- Final Decision: Energex's FRC Pass-through Application (November 2008)
<http://www.qca.org.au/files/E-CPTA-QCA-FINALReport-FRCenergex-1108.pdf>

4.2 Legislative Requirements

The Electricity Act requires that the network cost component of the BRCI reflect the Authority's view of the likely total annual revenue requirements of the transmission and distribution networks in Queensland.

4.3 Draft Decision

Unlike other elements of the BRCI, the Authority is not required to consult on the network cost component. However, due to the significance of these costs in terms of the overall BRCI, the Authority has sought stakeholder views on relevant network cost issues.

In its Draft Decision, the Authority noted that suggestions made by some stakeholders in response to the Interim Consultation Notice, to exclude part or all of network costs from the calculation of the BRCI were inconsistent with the requirement in the Electricity Act that the network cost component of the BRCI include the Authority's view of the likely total revenue requirements for transmission and distribution networks in Queensland.

Based on the information available at the time of the Draft Decision, the Authority's assessment of distribution and transmissions network costs was as outlined in Table 4.1.

Table 4.1 – Summary of network costs (\$m) – Draft Decision

<i>Energex</i>	<i>2008-09</i>	<i>2009-10</i>	<i>% change</i>
Original AARRs	879.6	927.9	5%
Minor AARR adjustments	(9.6)	(11.6)	21%
Capex cost pass-through	8.5	73.5	762%
FRC cost pass-through	15.0	30.0	100%
Removal of non-DUOS revenue	(18.5)	(19.5)	5%
Adjusted revenue	875.0	1,000.3	14.3%
<i>Ergon Energy</i>	<i>2008-09</i>	<i>2009-10</i>	<i>% change</i>
Original AARRs	812.5	860.4	6%
Minor AARR adjustments	1.5	2.2	47%
Removal of non-DUOS revenue	(7.4)	(7.6)	3%
Removal of Mt Isa network costs	(9.8)	(10.4)	6%
Cyclone Larry cost pass-through	5.0	5.8	16%
Adjusted revenue	801.8	850.4	6.1%
<i>Powerlink</i>	<i>2008-09</i>	<i>2009-10</i>	<i>% change</i>
Maximum allowable revenue	595.9	661.4	11.0
TUOS cost pass-through for Energex and Ergon Energy	454.3	503.2	10.8
Total network costs	2,131.1	2,353.9	10.5

Source: QCA various decisions. TUOS MAR from AER 2007. TUOS pass-through provided by Energex and Ergon Energy.

Note: Totals may not add due to rounding

Distribution costs

In its Draft Decision, the Authority applied the same approach to setting distribution costs as it had used in making its original 2008-09 Final Decision. Consistent with that approach, the starting point was taken as the original AARRs' the Authority set for Energex and Ergon Energy in its 2005 Final Determination.

These were then adjusted, as shown in Table 4.1, to reflect a number of subsequent adjustments relating to:

- (a) minor adjustments arising from the implementation of the 2005 Final Determination;
- (b) removal of revenue from non use-of-system services; and
- (c) a number of cost pass-through decisions made during the current regulatory period.

Minor Adjustments

As required in its 2005 Final Determination, the Authority adjusted the value of the opening asset bases for Energex and Ergon Energy to correct for deviations between actual and forecast capital expenditure up to 30 June 2005. This resulted in minor adjustments to both distributors' AARRs. The Authority also corrected slight errors made in setting Energex's AARRs.

Energex – Capital Expenditure Pass Through

In March 2007, the Authority approved the pass through of an additional \$720 million of capital expenditure by Energex (QCA, 2007c). The AARR adjustments for the capital expenditure pass through in the Draft Decision were the net result of costs associated with the additional capital expenditure and the revenue smoothing that the Authority applied to Energex at the time of the cost pass-through decision.

Removal of Non-DUOS Revenue

At the time the Authority made its 2005 Final Determination, the AARRs the Authority approved for the distributors included revenue required for the provision of non-distribution use of system (non-DUOS) services which were billed separately to DUOS services.

In December 2007, the Authority (QCA, 2007b) decided to treat these services as excluded distribution services. As a result, the Authority removed the operating and capital costs associated with providing excluded distribution services from the distributors' AARRs which resulted in a consequential reduction in the revenue requirement for the distributors.

Energex - FRC Cost Pass Through

In November 2008, the Authority approved the pass through of costs incurred by Energex in meeting its obligations under FRC (QCA, 2008d). The Authority had previously allowed Energex to raise an additional \$15 million of revenue in its distribution prices for 2008-09 in anticipation of approving some level of cost pass through. The Authority's Final FRC Decision allowed Energex to raise a further \$30 million of revenue in 2009-10. Consequently, for the 2009-10 BRCI Draft Decision, the Authority adjusted Energex's original AARR for 2009-10 to allow for revenues associated this cost pass-through.

Ergon Energy – Cyclone Larry Cost Pass Through

In September 2008, the Authority released its Final Decision that approved the pass through of capital costs of \$6.7 million and operating costs of \$7.9 million incurred by Ergon Energy in 2005-06 in response to Severe Tropical Cyclone Larry (QCA, 2008a). In its Final Decision, the Authority reported that the pass-through allowed Ergon Energy to raise an additional \$5.0 million in its 2008-09 revenue and a further \$5.8 million in 2009-10. Consequently, for the 2009-10 BRCI Draft Decision, the Authority adjusted Ergon Energy's original AARR for 2009-10 to allow for this recovery.

Ergon Energy – Mt Isa Network Costs

The Authority excluded Ergon Energy's AARR revenues associated with Mt Isa network costs when calculating the network cost component for the 2009-10 BRCI Draft Decision in order to ensure consistency with its calculation of the Queensland NEM load. The Authority excluded these costs in 2008-09 in its remade 2008-09 BRCI Decision.

Under- and Over-Recovery of Revenue

Consistent with its approach in calculating the BRCI for 2008-09, the Authority did not adjust the distributors' AARRs for the annual under or over-recovery of revenue for the purpose of calculating the 2009-10 BRCI.

The Authority has maintained the view that any under or over-recovery of revenue should not be included in the AARRs for the purposes of calculating the BRCI as these adjustments do not reflect a change in the level of underlying costs and revenue requirements of the distributors. The Authority has previously stated that, under the existing revenue cap form of regulation, it is assumed that a distributor's underlying costs, and therefore its revenue requirement, does not vary with actual energy consumption through the regulatory period. Consequently, over time, unders and overs will net each other out without impacting the underlying costs.

Transmission costs

The Authority's estimate of the NEM load for Queensland reflects the load supplied to customers through the distribution networks.

To be consistent with that approach, the Authority based its estimate of transmission revenue requirements on the TUOS charges that Powerlink levies on Energex and Ergon Energy, and which they pass through to customers. At the time of the 2009-10 BRCI Draft Decision, Powerlink charges for 2009-10 were not available. The Authority therefore estimated these by calculating the proportion of Powerlink's 2008-09 revenue cap accounted for by TUOS charges and applying this same proportion to Powerlink's 2009-10 revenue cap as calculated by the AER in its Final Decision on Powerlink's revenue cap for 2007-08 to 2011-12. On this basis, the Authority estimated in its Draft Decision that TUOS costs for 2009-10 would be approximately \$503.2 million.

The Authority noted that this data would be updated for actual Powerlink TUOS charges in its Final Decision.

In addition to Powerlink's charges, the Draft Decision also recognised that the distributors incur other transmission-related costs, including avoided TUOS payments to embedded generators and payments to other distribution network service providers for network services which are included in the estimates of network costs. The total of these transmission-related costs were reflected in the TUOS charges calculated by the distributors for pass-through to distribution customers.

As with distribution costs, the Authority did not adjust TUOS cost for the annual under or over-recovery of TUOS revenue collected by Energex and Ergon Energy in calculating the BRCI.

Submissions in response to the Draft Decision

In response to the Draft Decision, AGL (2008e) again noted that, in its view, the network costs included in the BRCI were not representative of the network costs retailers are likely to incur from Energex in respect of its small regulated customers.

In response, the Authority notes that the network cost component has been calculated in accordance with the requirements of the legislation and the Current Delegation.

Origin Energy (2008a,e) requested that the Authority provide a complete reconciliation of capital expenditure cost pass throughs commencing from 2007-08 as it was concerned that Energex had been granted a number of large cost pass-throughs which had not been accounted for in the BRCI process.

In response, the Authority notes that, other than two recent cost pass-through decisions for Ergon Energy which were confidential (see discussion below), all the Authority's cost pass-through decisions affecting Energex and Ergon Energy during the current regulatory period are publicly available from its website. All of these have been taken into account in the calculation of network costs in the relevant years.

4.4 The Authority's Final Decision

Since the Draft Decision was released, three changes have been made to estimated network costs for 2009-10, as noted below. All other aspects of the network cost calculation remain as detailed in the Draft Decision and noted above.

Adjustment to Ergon Energy's Cyclone Larry Cost Pass-through Revenue

In April 2009, the Authority released an erratum to its Final Decision on Ergon Energy's Cyclone Larry cost pass-through application (QCA, 2009a) which corrected an error in the calculation of revenue associated with the approved costs. As a result, the amount of revenue Ergon Energy is allowed to raise as a result of the Cyclone Larry cost pass through increased. This resulted in Ergon Energy's approved revenue for 2009-10 AARR being increased by a further \$2.6 million, from \$5.8 million to \$8.4 million.

Ergon Energy – Other Cost Pass-through Decisions

In November 2008 and January 2009, the Authority received two capital expenditure cost pass-through applications from Ergon Energy under the special provisions established in the Authority's 2005 Determination. One application was made under the provision related to large projects that were known at the time but were uncertain to proceed and the other was made under the provision related to large projects that were not foreseen at the time but involved capital expenditure above a set threshold.

Each of the additional capital expenditure pass-through applications from Ergon Energy concerned capital projects in relation to a single large customer. Ergon Energy noted that the details contained in the applications were commercially sensitive as the capital expenditure costs claimed on each application only concerned a single customer. The Authority accepted Ergon Energy's arguments regarding the confidential nature of the information contained in the applications and agreed to treat both applications on a confidential basis.

As a result, the Authority did not undertake a public consultation process for these applications or publicly release its Decisions. The Authority approved both cost pass-through applications, the first in February 2009 and the second in April 2009.

While the Authority is not in a position to disclose the details of the individual cost pass-through decisions concerned, the combined capital expenditure approved was \$26.3 million and the impact on Ergon Energy's AARR in 2009-10 was an increase of \$2.9 million revenue.

Transmission costs

In the Draft Decision, the Authority indicated that the estimate of transmission costs would be revised in the Final Decision to reflect the actual TUOS charges to be passed through from Powerlink to Energex and Ergon Energy. For 2009-10, it is now estimated that transmission costs will be \$525.5 million, compared to an estimate of \$503.2 million at the time of the Draft Decision.

As with distribution costs, the Authority has not adjusted the TUOS costs for the annual under or over-recovery of TUOS revenue collected by Energex and Ergon Energy in calculating the 2009-10 BRCI Final Decision.

Network Costs for 2009-10

Table 4.2 summarises the network cost components to be included in the calculation of the 2009-10 BRCI in this Final Decision.

For this 2009-10 Final Decision, the Authority estimates the relevant network costs to be \$2,131 million in 2008-09 and \$2,382 million in 2009-10, an increase of 11.8%.

Table 4.2 – Summary of network costs (\$m) – Final Decision

<i>Energex</i>	<i>2008-09</i>	<i>2009-10</i>	<i>% change</i>
Original AARRs	879.6	927.9	5.5%
Minor adjustments	(9.6)	(11.6)	20.8%
Capital expenditure cost pass-through	8.5	73.5	764.7%
FRC cost pass-through	15.0	30.0	100%
Removal of non-DUOS revenue	(18.5)	(19.5)	5.4%
Total Energex costs	875.0	1000.3	14.3%
<i>Ergon Energy</i>	<i>2008-09</i>	<i>2009-10</i>	<i>% change</i>
Original AARRs	812.5	860.4	5.9%
Minor adjustments	1.5	2.2	46.7%
Removal of non-DUOS revenue	(7.4)	(7.6)	2.7%
Mt Isa costs	(9.8)	(10.5)	7.1%
Cyclone Larry cost pass-through	5.0	8.4	68.0%
Confidential cost pass-through	na	2.9	na
Total Ergon Energy costs	801.8	855.8	6.7%
<i>Transmission</i>	<i>2008-09</i>	<i>2009-10</i>	<i>% change</i>
Powerlink charges (Energex and Ergon Energy)	444.8	514.0	15.6%
Avoided TUOS payments (Energex and Ergon Energy)	4.3	3.5	-19.2%
Unregulated Powerlink charges (Energex and Ergon Energy)	3.3	5.9	77.6%
Other charges	1.9	2.2	16.6%
Total transmission costs	454.3	525.5	15.7%
Total network costs	2,131.1	2,381.6	11.8%

Source: QCA various decisions. TUOS MAR from AER 2007. TUOS pass-through provided by Energex and Ergon Energy.

Note: Totals may not add due to rounding.

5. RETAIL COSTS AND MARGIN

Retail costs relate to the services provided by a retailer to its customers. The Authority is required to consider costs in relation to a representative retailer, rather than an actual retailer, that already has a significant share of the market, is efficient and has a customer base that is representative of all customers in Queensland connected to the NEM.

Retail costs comprise retail operating costs, customer acquisition and retention costs and a retail margin. Retail operating costs, in dollar terms, are expected to increase by 5.4% in 2009-10 while costs relating to customer acquisition and retention are expected to increase by 2.1%. Combined, these costs are expected to increase by 4.6%

For the 2009-10 BRCI, the Authority has maintained the net retail margin at 5% on the basis that this should provide a reasonable return to a retailer for the risks that it faces. The retail margin has remained unchanged since the first BRCI tariff year in 2007-08. In total, retail costs, including the retail margin, are expected to increase by 8.1% from \$437.2 million in 2008-09 to \$472.6 million in 2009-10.

5.1 Background

The retail cost component of the BRCI relates to the services provided by an electricity retailer to its customers, excluding those costs simply passed through to consumers. There are two broad categories of retail costs that are incurred by a retailer - retail operating costs and customer acquisition costs.

Retail operating costs include customer administration (including call centres), billing and revenue collection, IT systems and regulatory compliance and may include costs associated with metering and data services that are not already included in distribution charges. Customer administration and billing generally account for over half of retail operating costs.

Customer acquisition and retention costs are related to acquiring new customers, retaining existing customers and transferring existing non-market customers onto market contracts. These costs include: marketing, advertising, sales overheads, door-to-door/commission/agent costs and telesales.

The retail margin is the amount that a retailer earns from its activities net of its costs. The gross retail margin can be defined as the retailer's revenue minus the cost of energy and network costs. Hence, the gross margin includes the retailer's operating costs, while the (smaller) net margin is what remains after the retailer's operating costs are subtracted from the (larger) gross margin. References in the Queensland legislation to the retail margin refer to the net margin.

5.2 Legislative Requirements

The Electricity Act and the Electricity Regulation specify how the retail cost component of the BRCI is to be determined. The Electricity Act requires that retail costs must reflect the Authority's view of the likely cost of providing retail services to Queensland customers connected to the national grid. This view must be based on the cost of providing retail services for an efficient electricity retailer that:

- (a) is operating separately from any other business (that is, the business is a stand-alone Queensland retailer);
- (b) has a significant share of the retail electricity market in Queensland;

- (c) provides retail services to a cross-section of customers throughout Queensland in the same proportions as the customer mix for Queensland as a whole; and
- (d) earns a reasonable retail margin.

In addition, the Electricity Regulation requires that the Authority must consider the following cost categories in determining retail costs:

- (a) billing;
- (b) customer call centres;
- (c) credit management;
- (d) energy trading activities;
- (e) corporate overheads, including, for example, treasury functions, human relations and facilities management;
- (f) information technology systems; and
- (g) any other cost category the Authority considers reasonable.

5.3 Draft Decision

In its Draft Decision, the Authority estimated retail operating costs and customer acquisition and retention costs, separately.

Retail operating costs

In calculating retail operating costs, the Authority continued with the benchmarking approach adopted for the 2007-08 BRCI tariff year. Retail operating costs were calculated by escalating the benchmark cost established for 2006-07 to account for inflation and wages growth in the intervening period. In addition to the annual escalation for price and wage inflation, FRC-related costs were accounted for in 2007-08. This approach had been broadly supported in submissions to previous Decisions.

On this basis, the Authority estimated 2009-10 retail operating costs to be \$83.19 per customer, representing a 2.8% increase on the 2008-09 figure (\$80.96) reported in the Authority's 2008-09 Final Decision and in the Remade Decision.

Customer acquisition and retention costs

In the 2008-09 BRCI Decision, the Authority introduced a new⁵ two-step process to estimate customer acquisition and retention costs. The two steps involve first estimating the cost per customer of customers transferring or switching contracts. The second step involves estimating the number of customers transferring or switching contracts.

In its Draft Decision, the Authority accepted CRA's advice and escalated the costs established for 2007-08 (the base year) for a customer switching retailer (\$171.43) and transferring to a market contract with the same retailer (\$100.00) to 2009-10 values based on a weighted average of price (40%) and wage (60%) inflation in 2007-08 and 2008-09. On this basis, the Authority

⁵ Previously, in 2007-08, the Authority had used a loss of scale approach whereby a cost of \$2 per customer was estimated as being the average cost to retailers of losing scale, spread across all customers.

estimated customer acquisition costs in 2009-10 to be \$183.67 per customer for those switching retailer and \$107.14 per customer for those transferring from notified prices to a market contract with the same retailer.

In terms of estimated numbers of customers transferring or switching contract, CRA advised the Authority that it was having difficulty reconciling the NEMMCO data when producing estimates of customer switching. As a result, CRA decided to use the same switching and transfer numbers that it had used in the 2008-09 calculation. At the time, the Authority noted that it would seek to revise these calculations for the Final Decision once additional or better data became available.

Retail margin

In its Draft Decision the Authority remained of the view that a retail margin of 5% should provide a reasonable return for the risks that it faces. The Authority found no strong evidence that a reasonable margin sought by retailers would be materially different from that which had applied in 2008-09.

The costs of providing retail services, as estimated in the Draft Decision, are summarised in Table 5.1.

Table 5.1 – Change in Retail Cost Components, 2008-09 to 2009-10 (\$m), Draft Decision

<i>Retail cost component</i>	<i>2008-09</i>	<i>2009-10</i>	<i>% change</i>
	\$m	\$m	%
Operating costs	156.1	165.7	6.1
Customer acquisition costs	51.4	53.0	3.2
Retail margin (5%)	224.7	251.1	11.8
Total retail costs	432.2	469.9	8.7

Source: Table 4.1 of 2009-10 Draft Decision Benchmark Retail Cost Index for Electricity: 2009-10 December 2008 (p.33). Numbers may not add due to rounding.

Submissions in response to the Draft Decision

Retail operating costs

AGL (2008e) supported the benchmark escalation approach that the Authority used to estimate retail operating costs.

Origin Energy (2008e) noted that the Australian Energy Regulator (AER) had recognised increases in the costs of capital affecting regulated transmission and distribution businesses. Origin Energy suggested that this was despite declining global benchmark interest rates (i.e. the 'risk free rate') because there had been a significant increase in risk spreads or the so-called debt risk premium (DRP).

Origin Energy also noted that large retailers generally have a credit rating of B or B+ which implies that these businesses are riskier than monopoly businesses such as the transmission and distribution entities. Therefore, Origin considered it appropriate that rates of return and costs of

capital for large retail businesses (ignoring all other risk parameters) should be greater than for monopoly businesses.

However, Origin Energy suggested that, at face value, the method of escalation proposed by the Authority was reasonable based on information available at the time.

In response to the Authority's invitation for interested parties to provide further submissions addressing the changing economic environment noted in the Minister's February 2009 letter attaching the revised delegation, Origin Energy (2009a) reiterated its earlier view that there had been an increase in the cost of capital due to a rise in the debt premium and that higher rates of return and cost of capital were required by retail businesses compared to monopoly assets given their (lower) credit rating of B or B+.

Origin also pointed to a recent AER draft determination that had proposed a nominal WACC value for network businesses of 8.6% and claimed that this number had been the subject of considerable controversy in terms of whether it was commercially realistic in the face of the credit crisis and the prevailing debt premiums.

Customer acquisition and retention costs

In its submission on the Draft Decision, Origin Energy (2008e) suggested that retailers were only receiving \$1.91 per customer to account for customer acquisition costs and that this was well below CRA's estimate for customer acquisition costs of \$26.89 per customer in 2009-10.

However, Origin Energy appears to have misinterpreted the 2009-10 Draft Decision and is comparing the amount allowed for customer acquisition costs of \$2 per customer in 2007-08, based on a loss of scale approach that reflected net customer losses, rather than the actual 2008-09 approach or the proposed 2009-10 approach, both of which delivered much higher allowances for customer acquisition and retention costs and, in the case of the 2009-10 Draft Decision, did include the CRA estimate of \$26.89 per customer.

TRUenergy (2008d) suggested that the Authority should not include the CRA estimate of 'transfers to a market contract with the same retailer' in its customer acquisition and retention cost calculation on the grounds that there was no recognition of the costs associated with customers transferring from one market contract to another market contract with the same retailer.

However, CRA has advised the Authority that it does not believe that market-to-market transfers have been excluded from its analysis as its analysis does not discriminate between transfers from notified prices to market contracts as against transfers from one market contract to another.

TRUenergy also recommended that the forecast the churn rate for the 2009-10 BRCI should be estimated by using the customer transfer rate for the preceding 12-month period, as at the data cut-off date, with no subsequent corrections for the actual transfer rate.

Origin Energy (2009a) suggested that the extension of time provided in the Minister's February 2009 Delegation, provided the Authority with the opportunity to use more recent customer transfer data from NEMMCO in estimating customer transfer costs for 2009-10. Origin noted that this would align the number of months of actual data available with what had been used in the 2008-09 process.

5.4 The Authority's Final Decision

The legislation sets out the retail cost categories that the Authority is required to consider in calculating the BRCI.

The estimates of retail costs per customer in 2009-10 have been made based on estimates of customer numbers from Energex and Ergon Energy. For 2009-10, the Authority's estimate of total customer numbers is 1,978,965. This figure is slightly higher than that reported in the Draft Decision, which was based on a straight line forecast of growth in customer numbers between 2007-08 and 2008-09.

Retail Operating Costs

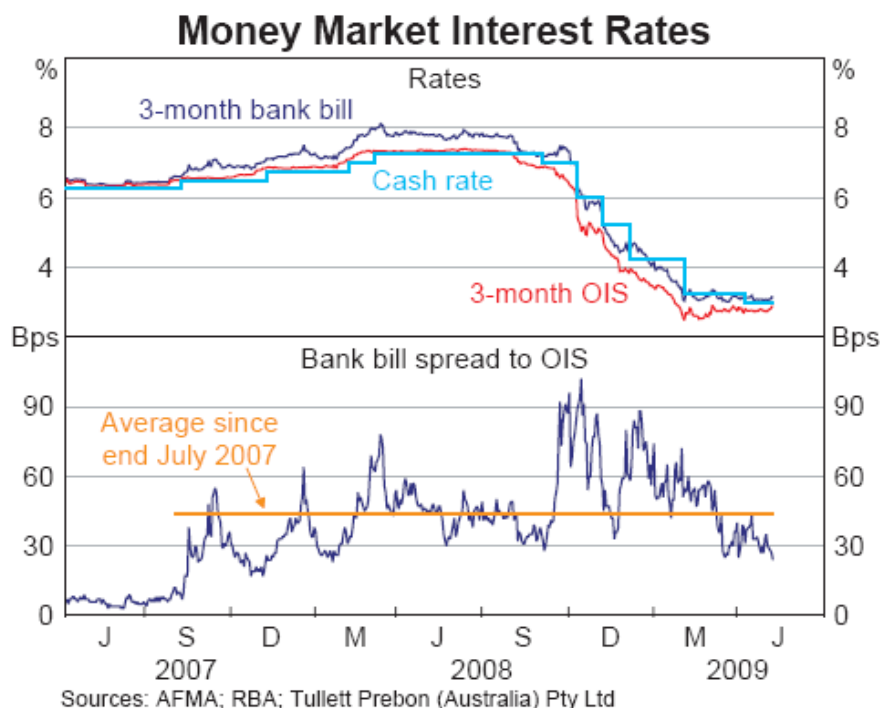
In its submission(s), Origin Energy questioned whether retail operating costs were adequately accounting for the higher cost of capital. However, the AER determinations referred to by Origin Energy in support of this argument were decisions concerning transmission and distribution entities, which are capital intensive due to the vast physical assets they own and finance rather than working capital intensive.

While Origin Energy claimed that businesses were facing increased costs due to higher debt premiums, it is not clear that this is the case.

In response to the global financial crisis, the Reserve Bank of Australia has lowered the cash rate by 425 basis points, from 7.25% on 2 September 2008 to 3.0% as at 2 June 2009. Similarly, all the major central banks have significantly lowered their benchmark interest rates.

While the rebalancing of global credit markets has seen risk spreads widened, the magnitude of the drop in central bank benchmark interest rates appears to be much greater than the average increase in the, globally-set, debt risk premium or risk spread.

As illustrated in Figure 5.1, the difference in the falling cash rate and the rising debt risk premium (as indicated by bank bill spreads) will most likely offset higher debt margins faced by retailers in 2009-10.

Figure 5.1 – Change in the cash rate and bank bill spreads, 2007-2009

Source: *Statement on Monetary Policy, 8 May 2009, Reserve Bank of Australia.*

Note: OIS (Overnight Index Swap) is the market price of the RBA cash rate.

As was the case in 2008-09, in 2009-10 the Authority has estimated retail operating costs by escalating the benchmark cost of \$75.00 per customer established in 2006-07 to account for inflation and wages growth in the intervening period.

The escalation factor is based on a 40/60 weighting of CPI and wage inflation as measured by the wage price index (WPI). The inflation forecast for 2009-10 of 2.5% is sourced from the Reserve Bank's Statement on Monetary Policy (8 May 2009) and the wages forecast of 3.4% is sourced from the June quarter 2009 ANZ Economic Outlook (6 April 2009).

On this basis, the Authority estimates 2009-10 retail operating costs to be \$83.19 per customer representing a 2.8% increase on the estimated costs for 2008-09 (\$80.96).

Customer Acquisition and Retention Costs

Customer acquisition and retention costs attracted significant comment in submissions in response to the Authority's Draft Decision. There was a view put by retailers that the rate of customer churn in 2008-09, including switches and transfers, had been underestimated and that this would make it difficult to maintain retailer headroom in 2009-10. However, much of the comment in submissions related to the impact of the change in framework implemented in the Authority's 2008-09 BRCI Decision and is not relevant in the context of this 2009-10 Final Decision.

Numbers of customer switches and transfers

As the Authority noted in its Draft Decision, CRA had difficulty analysing the available NEMMCO market transfer statistics to separate customers switching between retailers from customers staying with their retailer but transferring to market contracts or the paper transfers resulting from customers being transferred between subsidiaries of the same retailer. It was

hoped at the time of the Draft Decision that CRA would be able to resolve this issue but this has not been possible given the inadequacies in the available data. CRA have therefore continued with the approach adopted in the Draft Decision and used the same customer switching and transfer numbers for calculating customer acquisition and retention costs in the 2009-10 BRCI as it had used in the 2008-09 calculation. On this basis, switches from retailer to retailer are estimated to be 217,536 and customer transfers to a market contract with the same retailer are estimated to be 122,032.

Implicit in this approach, CRA is forecasting a fall in churn rate. CRA believes this is consistent with what it would expect to occur as the market moves further away from the introduction of FRC.

The Authority acknowledges the inherent difficulties involved in estimating accurate churn and transfer data based on the market transfer statistics provided by NEMMCO. The Authority has discussed these problems with NEMMCO which will endeavour to provide statistics aggregated to company level so that spurious within-company transfers are no longer counted as customer transfers between retailers. NEMMCO has advised that these company-level statistics should be available from June 2009.

The Authority notes the comments from TRUenergy (2008d) and agrees that, in normal circumstances, changing the time period of the data to be used could avoid the need for subsequent revisions. However, in this particular instance, the choice of the time period of the data to be used will not overcome the underlying problem of the quality of the data available.

Costs of customer switches and transfers

Consistent with its Draft Decision, the Authority has escalated the costs established in 2007-08 (the base year) for a customer switching retailer (\$171.43) and transferring to a market contract with the same retailer (\$100.00) to 2009-10 values based on a weighted average of price (40%) and wage (60%) inflation in 2007-08 and 2008-09. The escalation factor used for 2009-10 is the same as used to escalate retail operating costs, that is, an inflation forecast of 2.5% and a wages forecast of 3.4%. On this basis, the Authority estimates customer acquisition costs in 2009-10 to be \$181.83 per customer switching retailer (equivalent to \$19.99 per customer across all customers) and \$106.07 per customer transferring to a market contract with the same retailer (equivalent to \$6.54 per customer across all customers).

In total, customer acquisition and retention costs are estimated to increase by 2.1% from \$51.4 million in 2008-09 to \$52.5 million in 2009-10.

Retail Margin

The retail margin investors would typically seek from a business depends on the various risks inherent in the business. Over time, a retail margin that was higher or lower than an efficient level would result in over or under-investment.

The retail margin is calculated as a percentage of total costs (energy, network and retail costs (excluding margin)). This approach recognises that a retailer is exposed to changes in each component of the costs of supplying energy to customers.

In its 2007 08 BRCI Decision, the Authority considered margins that had been accepted by regulators in other jurisdictions (which ranged from 2% to 8%) and elected to apply a 5% margin which was around the mid-point of this range. CRA (2007) also advised the Authority that it believed a margin of 5% appropriately accounted for the volume and price risks faced by retailers in the Queensland market.

In considering whether the retail margin should be changed in 2009-10, CRA considered the impact of the global financial crisis and concluded that there had been no overall change in the risk profile of the (representative) retailer. The issues relating to risk associated with debt and the financing of working capital have been considered above in relation to retail operating costs.

The Authority acknowledges the point made by both AGL (2008a) and Origin Energy (2008a,b) that a clear understanding of the relationship between retail costs and retail margin is important when determining the 2009-10 BRCI. However, the Authority is of the view that, as changing costs have been accounted for in each component of the BRCI, these fluctuations do not add to the risks faced by retailers or suggest that some greater percentage retail margin is appropriate. If all other cost components are addressed correctly, then the percentage retail margin should not need to change across the reference period.

While not the view of some retailers, the Authority finds no strong evidence that a reasonable retail margin would be materially different from that applicable to the Queensland market in 2008-09.

On this basis, the Authority has continued to apply a retail margin of 5%, resulting in the value of the retail margin increasing from \$229.6 million in 2008-09 to \$255.5 million in 2009-10. In total, retail costs (including retail margin) have increased from \$437.2 million in 2008-09 to \$472.6 million in 2009-10.

In summary, the costs of providing retail services in this Final Decision are as shown in Table 5.2.

Table 5.2 – Change in Retail Cost Components, 2008-09 to 2009-10 (\$m)

<i>Retail cost component</i>	<i>2008-09</i>	<i>2009-10</i>	<i>% change</i>
	\$m	\$m	%
Operating costs	156.1	164.6	5.4
Customer acquisition costs	51.4	52.5	2.1
Retail margin (5%)	229.6	255.5	11.3
Total retail costs	437.2	472.6	8.1

Note: Numbers may not add due to rounding.

6. NEM LOAD

The Electricity Act requires that the 2009-10 BRCI be determined by dividing the forecast total benchmark retail cost for the relevant tariff year (2009-10) by the NEM load for the previous calendar year (2008) in order to determine the unit cost of supplying electricity, expressed in c/kWh.

In this Final Decision, the Authority has determined that the 2008 NEM load was 36,851 GWh, a decrease of 0.5% from the 2007 NEM load used in the Authority's previous 2008-09 BRCI Decision (the Remade Decision). This reduction is primarily due to the continued inclusion of uncorrected errors in the 2007 NEM load where one directly connected transmission customer had not previously been identified as a directly corrected customer. Had the Authority been able to correct this error so that both years were calculated on a consistent basis, the change between years would have been a 1.6% increase, rather than the noted decrease.

6.1 Background

In the preceding chapters, the cost components of the BRCI have been considered. In order to determine the unit cost of electricity, the relevant quantity of electricity (the load) over which these costs are to be spread must also be determined.

6.2 Legislative Requirements

The Electricity Act requires that the BRCI for the relevant tariff year be determined by dividing the total benchmark retail cost for the tariff year by the NEM load for the previous calendar year in order to determine the unit cost of supplying electricity, expressed in c/kWh.

The Electricity Act defines the NEM load as the total of the loads for the State supplied at each transmission connection point to a supply network. The NEM load therefore excludes any customer loads supplied directly from the transmission network (directly connected customers), the loads of customers connected to isolated distribution systems not participating in the NEM (such as the Mt Isa network) and the loads of small non-registered generators embedded in the distribution networks of Energex and Ergon Energy that do not participate in the NEM.

6.3 Draft Decision

The Authority's 2009-10 Draft Decision included an estimate of the NEM load for the latter part of 2008, as the entire year's load data was not known at that time. The Authority noted that full year data for 2008 was expected to become available from the National Electricity Market Management Company (NEMMCO) in time for the 2009-10 Final Decision and that it would use that actual data in preparing its Final Decision.

In its Draft Decision, the Authority also identified and considered a number of other issues in determining the NEM load to be used as the denominator for the BRCI calculation.

Newly identified directly connected customer

Late in the process of preparing its Draft Decision, Powerlink identified an additional transmission node identifier (TNI) as being directly connected that had not previously been identified by Powerlink as a directly connected customer. The load associated with this particular TNI accounts for about 2% of the total Queensland load.

Powerlink also acknowledged that this customer had not been identified as a directly connected transmission customer in previous years. As a result, the NEM load for 2007 used in the

Authority's 2008-09 BRCI Decision and in the Remade Decision, and the relevant starting year for this 2009-10 Draft Decision, is higher than it would have been had this TNI been correctly identified. Excluding this TNI only from the NEM load for 2008 would create an artificial decrease in the NEM load between years of about 2%.

For the purposes of the Draft Decision, the Authority opted not to remove the load associated with this particular TNI in order to maintain comparability between years. The Authority also noted that, because the load of this particular TNI has remained relatively stable across the two years, the effect on the BRCI calculation of including or excluding this TNI (from both years) would not be material.

This issue was considered further in the context of a Consultation Paper released by the Authority on 8 May 2009 (see below).

Other directly connected customers

Energy passing through a single connection point wholly dedicated to servicing Country Energy's network in New South Wales (NSW) was also excluded from the NEM load calculation on the basis that this load was not supplied to Queensland end-users.

Loads of registered embedded generators

Load data supplied by NEMMCO includes loads supplied by registered generators embedded in the distribution networks of Energex and Ergon Energy that participate in the NEM, but excludes loads supplied by smaller unregistered embedded generators in these networks.

The Authority considered it appropriate that the load met by registered embedded generators⁶ be included in the calculation of the NEM load. This is because registered embedded generators supply electricity that would otherwise be supplied through transmission connection points to the distribution systems of Energex and Ergon Energy. These generators also have an impact on network costs which are accounted for in the distributors' revenue requirements.

While the Authority was able to source annual load data for unregistered embedded generators from Energex and Ergon Energy, it was not able to source a matching load profile. Therefore, to ensure consistency in the process of calculating the 2009-10 BRCI, the Authority has excluded the loads of unregistered embedded generators in the calculation of the 2009-10 NEM load as it had done in the 2008-09 Decision.

The relevant NEM loads for 2007 and 2008 as used in the Authority's Draft Decision are presented in Table 6.1.

⁶ The National Electricity Law requires all generators to be registered with NEMMCO unless an exemption has been granted by NEMMCO. NEMMCO has issued a standing exemption from registration for generators with a nameplate rating of less than 5MW. Generators with nameplate ratings between 5MW and 30 MW must apply to NEMMCO for exemption from registering and satisfy certain criteria.

Table 6.1 – Queensland load 2007 and 2008 (GWh) – Draft Decision

	2007	2008	%change
Total State NEM load	46,727	45,978	-1.6%
Less loads of directly connected customers	9,687	9,541	-1.5%
NEM load	37,040	36,437	-1.6%

Source: QCA 2009-10 BRCI Draft Decision

Submissions in response to the Draft Decision

A number of submissions received in response to the Draft Decision further highlighted the Authority's use of forecast and actual load data for calculating the overall unit cost of energy per customer (the NEM load).

Origin Energy (2008e) and the Queensland Consumers' Association (2008b) supported the use of actual load data in the Final Decision, rather than forecast data. The Queensland Consumers' Association also stressed the importance of using actual load data for future Draft Decisions to avoid significant differences in the BRCI calculated between the Draft and Final Decision.

Origin Energy also commented on issues raised by the Authority in relation to the misidentified TNI. Origin Energy considered the Authority's proposed treatment of this issue to be a transparent and sensible approach but questioned whether the current legislation for the calculation of the BRCI allowed the Authority to correct for the incorrectly identified TNI in the manner proposed. Origin Energy suggested that, as there was no methodological change involved, it did not believe the Authority was able to make the change it had proposed for the Final Decision (see further discussion on this issue at the end of this chapter).

6.4 Consultation Paper

On 8 May 2009, following receipt of the judgement in the judicial review of the Authority's 2008-09 BRCI Decision sought by AGL and Origin Energy, the Authority released a Consultation Paper discussing issues related to the construction of the NEM load. As the full 2008 actual load data was available from NEMMCO at the time, the Authority took the opportunity provided by the Consultation Paper to advise stakeholders of the possible options for calculating the NEM load to be used as the denominator in calculating the 2009-10 BRCI. This discussion is reproduced below.

Unidentified directly connected customer

In its 2009-10 Draft Decision, the Authority advised all parties that Powerlink had identified an additional TNI as being a directly connected customer to the transmission network, which it had not previously identified as such. This meant that the load from that particular TNI should have been excluded from previous calculations of the NEM load.

As this advice was received from Powerlink only shortly before the Authority's Draft Decision was due to be released, the Authority decided that it would not remove this particular TNI, which accounts for about 2% of the total Queensland load, for the 2009-10 Draft Decision. Instead, the Authority advised that it would resolve this issue in its 2009-10 Final Decision by removing this TNI load from both the 2007 and 2008 calculations of the NEM load so that the denominators in the BRCI formula would be constructed on a consistent basis.

Apportioning part of a TNI to the NSW grid

Subsequent to the Draft Decision, the Authority also identified that a portion of one TNI load, which passes through a Queensland TNI but then flows into the New South Wales grid, should have also been excluded from the NEM load calculation. Previous Decisions claimed that all these loads had been removed when in fact this one had not. In the adjustments noted below, the Authority has also included the NSW portion of this load in the proposed adjustment to the NEM load calculated for both 2007 and 2008 to be used in the 2009-10 BRCI.

The 2008 load for the denominator in the 2009-10 Final Decision

Table 6.2 shows the 2008 calendar year NEM load that the Authority used in its Draft Decision and the NEM load that it proposed to use as the denominators for calculating the 2009-10 BRCI in its Final Decision.

Table 6.2 – 2008 NEM Load (MWh) – 2009-10 Draft and (proposed) Final Decisions

<i>Load</i>	<i>Draft Decision 2009-10 2008 Load (Partially forecast data)</i>	<i>Final Decision 2009-10 2008 Load (Full year actual data)</i>
Total State NEM Load	45,978,000	47,367,386
Less directly connected customers previously identified	9,541,000	9,733,922
Less TNI not previously identified and portion of load flowing to NSW not previously removed	na	782,504
NEM load for 2008	36,437,000	36,850,890

Sources: NEMMCO and Powerlink

Adjusting the 2007 load to ensure consistency in the denominator

Table 6.3 shows the change (noted in the Consultation Paper) in the Authority's estimate of the 2007 (calendar year) actual NEM load after aligning the excluded TNIs in both years.

Table 6.3 – 2007 NEM Load (MWh) – 2009-10 Draft and (proposed) Final Decisions

<i>Load</i>	<i>Draft Decision 2009-10 2007 Load</i>	<i>Final Decision 2009-10 2007 Load</i>
Total State NEM Load	46,727,000	46,726,276
Less directly connected customers previously identified	9,687,000	9,686,561
Less TNI not previously identified and portion of load flowing to NSW not previously removed	na	780,856
NEM load for 2007	37,040,000	36,258,859

Sources: NEMMCO and Powerlink

Submissions in response to the Consultation Paper

Both Origin Energy (2009b) and AGL (2009b) objected to a revised calculation of the 2007 NEM load to be used in the 2009-10 BRCI calculation.

Origin Energy claimed that the proposed change was a correction of past errors, similar to the updating of past data inputs, and had the potential to distort the BRCI outcome.

AGL took a similar view arguing that, in order to comply with the recent Court decision, the Authority must include this additional TNI in its re-calculation of the NEM Load for the purpose of the recalculation of the 2008-09 BRCI, and exclude it for the purpose of the 2009-10 BRCI.

6.5 The Authority's Final Decision

In the Consultation Paper, the Authority proposed to calculate the NEM load for 2007 and for 2008 to be used as the denominator in calculating the 2009-10 BRCI as set out in Tables 6.2 and 6.3 making the adjustments noted to correct for a previously unidentified directly connected customer and to remove a portion of the load from one TNI that flows into the NSW grid.

Following release of the Consultation Paper and after further consideration of the judgment in the Judicial Review case, the Authority has decided not to make the changes proposed regarding the NEM load for 2007 indicated in Table 6.3. As a consequence, the NEM load for 2007 will remain as it was in that Decision and be set at 37,040 GWh.

This view is consistent with the concerns raised by Origin Energy in response to the suggestion in the Draft Decision and by Origin Energy and AGL in their submissions in response to the Consultation Paper.

The Authority's Final Decision on the NEM load for 2007 and 2008 is presented in Table 6.4. On this basis, the 2008 NEM load, at 36,851 GWh, is 0.5% less than the 2007 NEM load primarily due to the continued inclusion of uncorrected errors in the 2007 NEM load.

Had the errors in the 2007 NEM load been corrected, as originally proposed by the Authority in its Draft Decision and again in the recent Consultation Paper, the NEM load would have shown an increase of 1.6% between the two years.

Table 6.4 – Queensland load 2007 and 2008 (GWh) – Final Decision

	<i>2007</i>	<i>2008</i>	<i>% change</i>
Total State NEM load	46,727	47,367	-1.4
Less directly connected customers previously identified in the Draft Decision	9,687	9,734	0.5
Less a portion of load associated with a TNI not previously identified in the Draft Decision	Na	783	na
NEM load	37,040	36,851	-0.5

Sources: NEMMCO and Powerlink

7. 2009-10 BRCI FINAL DECISION

The Authority estimates the BRCI to be 13.87 cents per kWh in 2009-10 compared to 12.40 cents per kWh in 2008-09. This represents an expected increase of 11.82% in the BRCI between 2008-09 and 2009-10.

The cost of energy is expected to increase by 11.40% in 2009-10 while total network costs are estimated to rise by 11.75% over the year. Retail costs are expected to be 8.10% higher in 2009-10.

The 2008 NEM load, at 36,851 GWh, is 0.5% less than that for 2007 primarily due to the removal of a previously unidentified directly connected customer from the 2008 NEM load.

7.1 Calculation of the BRCI for 2008-09 and 2009-10

In the preceding chapters, the Authority has set out its estimates of the individual components of the BRCI. A summary is provided in Table 7.1.

Table 7.1 – Components of the BRCI in 2008-09 and 2009-10

	<i>2008-09</i>	<i>2009-10</i>	<i>% change</i>
Cost of energy (\$million)	2,025	2,255	11.40
Network costs (\$million)	2,131	2,382	11.75
Retail costs (\$million)	437	473	8.10
NEM load of Queensland (GWh)	37,040	36,851	-0.51

Note: The NEM load has been calculated to the nearest kWh.

Based on the figures contained in Table 7.1, the Authority has calculated that the BRCI will increase by an expected 11.82% in 2009-10, as shown in Table 7.2.

Table 7.2 – Change in the BRCI and its components from 2008-09 to 2009-10 (c/kWh)

<i>BRCI cost component</i>	<i>2008-09 c/kWh</i>	<i>2009-10 c/kWh</i>	<i>Change (%)</i>	<i>Share of total costs 2008-09 (%)</i>	<i>Change in BRCI (%)</i>
Cost of energy	5.47	6.12	11.98	44.1	5.28
LRMC of energy	2.13	2.66	25.04	17.2	4.30
Purchase cost of energy	2.90	2.89	-0.52	23.4	-0.12
Other energy costs	0.44	0.57	31.26	3.5	1.10
Network costs	5.75	6.46	12.33	46.4	5.72
Distribution	4.53	5.04	11.26	36.5	4.11
Transmission	1.23	1.43	16.27	9.9	1.61
Retail costs	1.18	1.28	8.66	9.5	0.82
Operating costs	0.42	0.45	5.97	3.4	0.20
Acquisition/retention costs	0.14	0.14	2.66	1.1	0.03
Margin	0.62	0.69	11.82	5.0	0.59
Total	12.40	13.87	11.82	100.00	11.82

Note: Totals may not add due to rounding

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ATTACHMENT 1**CERTIFICATE OF DELEGATION****Under section 90(3) of the *Electricity Act 1994* (Qld)****Delegation**

In accordance with section 90(3) of the *Electricity Act 1994* (the Act), I delegate to the Queensland Competition Authority (QCA) the following functions and powers (the delegated activities):

1. Calculation of the Benchmark Retail Cost Index (BRCI) under Chapter 4, Part 2, Division 3 of the Act;
2. Application of the change in the BRCI to the tariffs for the previous tariff year as required by section 90(5) of the Act; and
3. Publication of the amended tariff schedule for the relevant tariff year in accordance with sections 90(2), 90(7) and 96 of the Act.

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

Conditions of delegation

1. The QCA must apply the change in the BRCI to the tariffs for the previous tariff year, taking into account any other changes to notified prices made by the Minister under the provisions of section 90 of the Act which are not the subject of this delegation, which will be advised prior to the required date for publication of the tariffs in accordance with the Act and this delegation.
2. The QCA must consider the following policy objective of the Queensland Government when exercising the delegated powers and functions:
 - a. the annual indexation of electricity tariffs by the index should ensure that existing retail headroom in the tariffs at the date of the Original Delegation made prior to the commencement of full retail competition¹ remains relatively stable (although not necessarily the same from year to year); and
 - b. 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;
3. In calculating the network cost component of the 2008-09 BRCI, and future tariff years, the QCA must apply the Annual Aggregate Revenue Requirement (AARR) determined for each year of Ergon Energy's current access arrangement (covering the period 2005-06 to 2009-10), and any changes to the AARR for any approved cost pass through made subsequent to the finalisation of the current access arrangement, without undertaking any re-smoothing of these AARR amounts;
4. The QCA must complete the delegated activities for the 2009-10 tariff year no later than 12 June 2009;

¹ The Original Delegation was made under section 90(3) of the *Electricity Act 1994* on 27 March 2007.

5. On the same day that the QCA gazettes the tariff schedule for a tariff year, the QCA must make a public announcement of the change to the notified prices; and
6. Any other conditions formally notified by the Minister from time to time.

This delegation revokes my delegation of 29 May 2009.



STEPHEN ROBERTSON MP
Minister for Natural Resources, Mines and Energy
and Minister for Trade

Dated: *3rd* June 2009