



Draft Decision

**Benchmark Retail Cost Index
for Electricity:
2009-10**

December 2008

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SUBMISSIONS

This report is a draft only and is subject to revision. Public involvement is an important element of the decision-making processes of the Queensland Competition Authority (the Authority). Therefore submissions are invited from interested parties concerning its assessment of the 2009-10 Benchmark Retail Cost Index (BRCI). The Authority will take account of all submissions received.

Written submissions should be sent to the address below. While the Authority does not necessarily require submissions in any particular format, it would be appreciated if two printed copies are provided together with an electronic version on disk (Microsoft Word format) or by e-mail. Submissions, comments or inquiries regarding this paper should be directed to:

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The **closing date** for submissions is **22 December 2008**.

Confidentiality

In the interests of transparency and to promote informed discussion, the Authority would prefer submissions to be made publicly available wherever this is reasonable. However, if a person making a submission does not want that submission to be public, that person should claim confidentiality in respect of the document (or any part of the document). Claims for confidentiality should be clearly noted on the front page of the submission and the relevant sections of the submission should be marked as confidential, so that the remainder of the document can be made publicly available. It would also be appreciated if two copies of each version of these submissions (i.e. the complete version and another excising confidential information) could be provided. Again, it would be appreciated if each version could be provided on disk. Where it is unclear why a submission has been marked “confidential”, the status of the submission will be discussed with the person making the submission.

While the Authority will endeavour to identify and protect material claimed as confidential as well as exempt documents (within the meaning of the *Freedom of Information (FOI) Act 1989*), it cannot guarantee that submissions will not be made publicly available. As stated in s187 of the *Queensland Competition Authority Act 1997* (the QCA Act), the Authority must take all reasonable steps to ensure the information is not disclosed without the person’s consent, provided the Authority is satisfied that the person’s belief is justified and that the disclosure of the information would not be in the public interest. Notwithstanding this, there is a possibility that the Authority may be required to reveal confidential information as a result of an FOI request.

Public access to submissions

Subject to any confidentiality constraints, submissions will be available for public inspection at the Brisbane office of the Authority, or on its website at www.qca.org.au. If you experience any difficulty gaining access to documents please contact the office (07) 3222 0555.

Information about the role and current activities of the Authority, including copies of reports, papers and submissions can also be found on the Authority’s website.

PREAMBLE

Since the introduction of full retail competition (FRC), small electricity consumers have been able to purchase electricity from a 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 Draft Decision, the Authority has estimated the increase in costs to be 13.63% between 2008-09 and 2009-10.

This change is made up of: an increase in energy costs of 15.8% (accounting for 50% of the total change) due primarily to rising fuel and capital costs; an increase in the transmission and distribution costs of 12.3% (accounting for 43% of the total change) reflecting ongoing significant investment in the distribution networks; and an increase in retail costs of 10.5% (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.

A change in the long-run marginal cost (LRMC) of energy contributed the bulk of the change in energy costs. The legislation requires that LRMC be based solely on the previous year's load, reflect the most efficient combination of plant to meet that load, regardless of the current plant configuration, and reflect current input prices for that whole load. Input costs have increased significantly over the last two years, according to independent expert advice that the Authority has used for the purpose of this Draft Decision.

The Authority invites submissions from interested parties on this Draft Decision. Respondents should submit these to the Authority no later than 22 December 2008.

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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 to be used to adjust notified electricity prices each year.

On 26 August 2008, the Minister for Mines and Energy (the Minister) delegated responsibility for calculating the 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 these prices by 1 March 2009.

Following the release of an Interim Consultation Notice on 2 July 2008, the Authority is now releasing this Draft Decision.

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 regulated (notified) 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.

Under the Electricity Act, the notified price of electricity is 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 Draft Decision

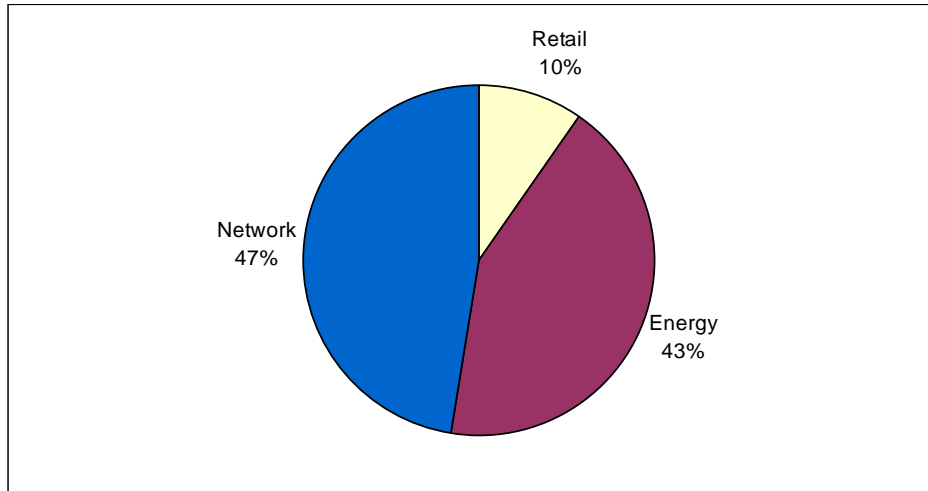
This report outlines the Authority's Draft Decision regarding the BRCI for 2009-10. It does not seek to either reiterate in detail matters previously considered by the Authority in past decisions or to detail the modelling undertaken to inform this decision.

As such, this Draft 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 2008-09

Source: QCA

The impact on annual electricity prices 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 90% of the total cost of supplying energy, changes in these components will potentially 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/legisln/current/e/electrica94.pdf>; and
- <http://www.legislation.qld.gov.au/legisln/current/e/electricr06.pdf>.

The Electricity Act allows the Minister to delegate the calculation of the BRCI to the Authority. On 16 March 2007, the Minister wrote to the Authority advising that he had delegated this responsibility to the Authority, subject to certain conditions (Original Delegation).

On 26 August 2008, the Minister provided the Authority with a revised certificate of delegation in relation to the 2009-10 BRCI Decision (Current Delegation). The Current Delegation, which is at **Attachment 1**, is the basis upon which this Draft Decision has been prepared. The new delegation requires the Authority to:

- (a) calculate the BRCI;
- (b) apply the change in the BRCI to the schedule of notified prices; and
- (c) publish, by gazette notice, the schedule of notified prices for 2009-10 by 1 March 2009.

The two conditions outlined in the Current Delegation are that:

- (a) annual indexation of electricity tariffs should ensure that retail headroom in the tariffs at the date of the Original Delegation 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 retail services to such customers at a loss.

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 the 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.

On 3 November 2008, the Authority hosted a second workshop 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, have been taken into account by the Authority in preparing this Draft Decision.

Final reports from CRA and ACIL can be obtained from the Authority's website.

1.5 Timetable for determining the BRCI for 2009-10

- Draft Decision released for comment 1 December 2008
- Submissions on Draft Decision close 22 December 2008
- Modelling data sets for final report to be released for comment 22 January 2009
- Comments on data sets due 30 January 2009
- Final Decision released and adjusted prices for 2009-10 published 27 February 2009

1.6 Submissions on the Draft Decision

Submissions on this Draft Decision must be received by the Authority by the close of business on 22 December 2008. The Authority will consider those submissions in preparing its Final Decision. The Authority will release its Final Decision and publish the notified prices for 2009-10 by 1 March 2009.

2. 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 of Queensland in that year. In forming this view, the Authority is obliged to take account of its latest estimate of the long run marginal cost (LRMC) of energy in the part of Queensland connected to the national grid and has a discretion to take account of the actual cost of purchasing energy (purchase cost of energy) in the State in that year.

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 a weighted average of these two costs.

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 considered the potential impact of the Commonwealth's proposed Carbon Pollution Reduction Scheme (CPRS) but decided not to recognise any impacts from this yet to be finalised scheme in the BRCI to be applied to prices in 2009-10. The Authority also gave consideration to alternate input cost estimates but has elected to continue with the same basic approach adopted in the previous year of basing input costs on a trend regression analysis, albeit updated 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 Queensland load.

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 recognised the cost of NEM participant fees and ancillary services charges paid by retailers.

Summing the energy costs described above, the estimated total energy-cost components of the BRCI were \$1,930 million in 2008-09 and \$2,154 million in 2009-10, an increase of 12%.

Note: The Authority has noted in chapter 5 that, based on the recent advice from Powerlink, there had been a directly connected transmission customer incorrectly identified in previous years as being served via the distribution system of Ergon Energy. For the purposes of this Draft Decision only, the Authority has continued to include that load as a distribution customer and, as such, the estimates in this Draft Decision reflect that decision (see chapter 5 for a more complete discussion of this issue).

2.1 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 of Queensland in that year. In forming this view, the Authority is obliged to take account of its latest estimate of the long run marginal cost (LRMC) of energy in the part of Queensland connected to the national grid and has a discretion to take account of the actual cost of purchasing energy (purchase cost of energy) in the State in that year.

This view must also take account of the 13% Gas Scheme under the Electricity Act and the Mandatory Renewable Energy Target (MRET) scheme under the *Renewable Energy (Electricity) Act 2000* (Cth).

The Electricity Act also 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 Regulation states 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 13% 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.

2.2 Submissions from Stakeholders

In response to the Interim Consultation Notice, the Authority received nine submissions from stakeholders. The comments in these submissions focused not only on issues raised in the Interim Consultation Notice but also on aspects of the 2008-09 BRCI Decision. In the process of preparing this Draft Decision, the Authority hosted two workshops to enable interested parties to discuss issues relating to the modelling work being undertaken by CRA and received further submissions and comments following the workshops.

LRMC of Energy

Comments in submissions generally suggested that the Authority had underestimated the increase in LRMC between 2007-08 and 2008-09. There was a general view that the LRMC of energy could be expected to increase in 2009-10, although concerns were raised that this increase would be underestimated if the Authority continued to use the same methodology.

A number of submissions suggested that the estimated increase in LRMC in 2008-09 was too low, based on comparisons with prevailing increases in input costs, inflation rates and interest rates. For example, Integral Energy (2008a) and Energy Australia (2008a) suggested there was upward pressure on LRMC inputs from rising capital and fuel costs, changes in the mix of generation and regulatory uncertainty that should be acknowledged in the BRCI.

To account for these increases in the BRCI, Integral Energy supported the use of the most current data for input costs, with particular emphasis on the cost of coal and gas technologies.

The trend approach adopted by the Authority for 2008-09 was criticised by AGL (2008a), Origin Energy (2008a) and TRUenergy (2008a,b), suggesting that this method of calculation failed to reflect the step-change in input costs that had occurred over the past two years. These submissions presented the view that historical trends were not appropriate where there had been a fundamental step change in the market.

AGL (2008a), Origin Energy (2008a) and TRUenergy (2008a) all suggested that data from the ACIL 2008 report provided evidence of a step change that had occurred in electricity generation costs. Origin Energy rejected the Authority's reasons for not using the ACIL 2008 data in calculating the LRMC for 2008-09. In particular, Origin Energy was opposed to what it regarded as an inconsistent or selective use of data from the 2007 and 2008 reports.

Similarly, AGL (2008a), Origin Energy (2008a) and TRUenergy (2008a) all suggested that the increase in generation costs suggested by the ACIL 2008 report should be reflected in the calculation of the LRMC of energy for 2009-10. AGL indicated that it would commission ACIL Tasman to update its 2008 report and suggested that this data should be used to calculate the LRMC for 2009-10.

AGL (2008a,b) contested the Authority's claim that removing short term influences from the LRMC of energy calculation was in keeping with the legislated methodology, asserting that the Authority had provided no evidence to support this position. Reflecting this view, AGL suggested that National or Queensland inflation rates for the period 2007-08 should be used in the calculation of the LRMC. Similarly, Origin Energy (2008a) suggested that the mid-point RBA target inflation rate was not an appropriate adjustment mechanism as it failed to capture current inflation data, and may lead to inconsistencies with the approach taken by other regulatory agencies.

In its submission, AGL (2008a) expressed concern about substituting actual data for forecast data (as was done in the 2008-09 decision), irrespective of any change in methodology. This position was supported by several retailers. AGL suggested that this constricted the subsequent year's correction, leading to margin erosion and that, as such, this was not a defensible approach. AGL recommended that LRMC and the energy purchase costs calculated for the 2008-09 BRCI based on the NEM Load be used as the "base year" and not recalculated.

Several submissions opposed the calculation of LRMC having regard to the requirements of the whole of system Queensland load. It was the suggestion that the total load patterns masked the inherent peakiness in the patterns of demand to which the BRCI generally applies. Integral Energy (2008b) and Energy Australia (2008) suggested that energy purchase costs should be afforded a higher weighting to account for this. APG (2008) suggested that this approach did not align with the purpose of the BRCI as an index of change in the cost of servicing the regulated retail customers.

Submissions generally favoured continued use of the greenfields¹ basis for modelling the LRMC plant mix, though it was recognised that there were issues with this approach.

¹ A greenfields assessment is a theoretical exercise whereby the plant mix is modelled as completely new, based on the prevailing conditions of that time. The alternative would be using an incremental approach, where new plant is modelled as required as an addition to the existing plant mix. The incremental approach resembles what would occur in reality.

In responding to the Interim Consultation Notice, several retailers supported the inclusion of expected impacts from the proposed CPRS in mid 2010 on the LRMC of energy. However, there were mixed views on how this impact should be factored into the BRCI.

APG (2008) suggested that the CPRS would have an impact on retail operating costs and margin that should be taken into account in calculating the 2009-10 BRCI. Ergon Energy (2008) and Integral Energy (2008b) stressed a need for certainty in accounting for this in the BRCI to enable forward contracting and confidence in the market.

Discussions on emissions trading in the first stakeholder workshop centred on the method by which the additional cost of carbon permits should be calculated. Whilst CRA had included costs at the wholesale level (as per the intent of the Commonwealth Government proposal), AGL had proposed that the per-tonne carbon cost be passed on in full to customers.

However, in its submission following the second workshop, AGL (2008d) observed that, under the methodology for calculating the LRMC of energy, the BRCI would reflect costs associated with the CPRS before these costs were incurred by retailers. AGL did not believe this was an appropriate outcome. This view seemed to be supported by most retailers at the workshop.

Conversely, Origin (2008d) stated that it would not support an approach that did not include the impacts of the CPRS, claiming that not to do so would represent a change to the methodology, rendering the approach 'theoretically unsound'. Nevertheless, Origin acknowledged that the release of the Commonwealth Government's White Paper in December 2008 would provide more insight about the emissions reduction target, trajectory and compensation mechanisms.

Purchase Cost of Energy

In its submission, AGL (2008a) noted that the Authority's method of layering hedges over 2 years was satisfactory for the purpose of calculating the BRCI. Origin Energy (2008a,b,c) and TRUenergy (2008b) also generally supported the Authority's approach to calculating energy purchase costs, although both retailers suggested that the model details required further explanation and that there was a need to reflect increased costs for 2009-10. AGL (2008a) and others maintained that stakeholders had not been provided with sufficient data to enable them to properly analyse or comment on the Authority's method of estimating energy purchase costs.

Queensland Electricity (2008), APG (2008) and Integral Energy (2008a) indicated that they would prefer to have the purchase cost of energy more transparently reflect the risk of variability in load and volume faced by retailers.

TRUenergy (2008a) suggested that the calculation of energy costs should exclude direct connect customers. Most submissions from retailers supported this view, that the NEM load for the State should be used to calculate costs, rather than the entire load for the state.

TRUenergy (2008b) suggested that, if purchase cost data for the period up until the start of the regulatory period could not be incorporated, the Authority should make provision for a 'true-up' so that any shortfall or excess resulting from the use of estimates could be redressed at the end of the period or in the context of the following decision.

In response to CRA's short papers on Transmission System and Scaling Factors (2008d), and Energy Purchase Costs (2008e) following the first workshop, Origin Energy (2008c) and AGL (2008c) suggested that the impacts of structural changes in the Queensland market needed to be considered. Origin Energy (2008c) suggested that structural changes and transient events (such as drought) that have occurred in the market over the past ten years be excluded from the calibration to better represent normal prices.

Weighting LRMC of Energy and Purchase Cost of Energy

The Queensland Consumers Association (supported by QCOSS) suggested that the Authority adopt a 75% weighting in favour of the LRMC of energy. However, the Queensland Consumers Association also noted its general concerns regarding the robustness of the LRMC calculation methodology as prescribed in the BRCI legislation. The Queensland Consumers Association and QCOSS both supported the retention of the 50/50 weighting in the short-term but suggested that the Authority should urgently pursue legislative changes to correct the restricted LRMC of energy approach and thus allow for adoption of a greater weighting for LRMC of energy.

Conversely, Energy Australia (2008), AGL (2008a) and Integral Energy (2008b) suggested that the BRCI should be more heavily weighted towards the purchase cost of energy. AGL noted that the layering of hedging costs over the long-term tends to smooth the purchase cost and thus the appropriate weighting should be 75% in favour of the energy purchase cost. Energy Australia considered the 50/50 weighting did not reflect the risks borne by retailers in the market and, as such, was contrary to the objective in the Minister's certificate of delegation to the Authority of maintaining retail headroom.

Other Energy Costs

Energy Australia (2008) and Origin Energy (2008a,b) suggested that the expansion of the MRET scheme had caused an upward movement in the price of Renewable Energy Certificates (RECs) that had not been reflected in the past calculations of the LRMC of energy. Origin Energy (2008a) also suggested that the Authority failed to consider any change to the renewable power percentage² (RPP) for 2009.

AGL (2008a) suggested that the Authority had failed to properly assess the MRET compliance costs incurred by retailers. AGL suggested that there is a lack of liquidity in the REC market and retailers of any significant size are not able to buy the volumes of RECs necessary at the 'market cost' but need to enter into contracts with renewable projects to underwrite the development of plant. AGL suggested that the same approach to RECs should be adopted as the Authority has adopted with other wholesale energy costs, namely 'weighting' the LRMC of energy against the REC purchase costs.

Alternatively, AGL (2008a,d) suggested that the REC component of the 2009-10 BRCI should be calculated with reference to a single year contracting time frame. At the same time, AGL indicated that it did not believe that this would constitute a change to methodology, and the REC cost forecast for 2008-09 should be used without any 're-calculation' or substitution of actual data for forecast data."

Origin Energy (2008d) recommended that the Department of Climate Change (DCC) MRET consultation paper 'Design Options for the Expanded National Renewable Energy Target Scheme' and the recent Treasury modelling of the expanded MRET scheme inform the calculation of the REC allowance in all of the LRMC of energy modelling scenarios. In relation to the RPP, AGL (2008d) suggested using the estimates in the DCC's recent discussion paper on MRET.

² The renewable power percentage (RPP) is the rate at which liable parties must surrender renewable energy certificates (RECs) to meet their MRET obligations each year.

2.3 The Authority's Position

Estimating the LRMC of Energy

In making its 2008-09 BRCI decision, the Authority undertook an extensive review of the methodology and input data used for calculating the LRMC of energy. This included several rounds of consultation with stakeholders (see the Authority's 2008-09 Final Decision). While some stakeholders may disagree with elements of that decision, to the extent that they reiterate in substance the issues raised in the 2008-09 BRCI decision in relation to the methodology and choice of input data, this Draft Decision does not re-address them.

For example, several submissions argued against the Authority's approach of estimating per unit long-run costs based on the costs of plant necessary to supply Queensland state load and then applying this per unit cost to the NEM load. However, the Authority remains of the view that its estimate of costs should reflect the generation plant on the ground and that to disregard this reality would be to ignore the economies of scale actually present in the market and would be counter to the objective of considering changes in the actual costs of supplying energy to customers in the most efficient way.

However, two issues relevant to the estimation of the LRMC of energy have been addressed in some detail in this year's Draft Decision, namely:

- (a) has 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 CPRS?

Has there been a step-change increase in energy generation costs?

Some retailers argued strongly that the LRMC component of energy costs did not take sufficient account of an apparent change in energy generation costs over the past few years. Retailers were also of the view that the apparent cost increases constituted a permanent change, or step-change, rather than a temporary shift from a balanced cost path.

The Authority undertook to investigate the step-change hypothesis following discussion on this issue at the first workshop. The Authority engaged ACIL Tasman (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.

ACIL Tasman approach

In its report, Fuel and capital costs in the NEM, Greenfield cost data for the calculation of the 2009-10 BRCI, ACIL identify a "step like change in capital costs over the past 24 months – mainly driven by a changes [sic] in steel prices and, to a lesser extent, labour costs" (ACIL 2008). Further, ACIL concluded that, while there had been a significant increase in generation costs in the past two years attributable to rising capital and labour costs, 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 other half of the recent cost increases would most likely unwind to pre-2006-07 levels in the short-term. Indeed, ACIL suggested that "most of the major suppliers will increase manufacturing capacity over the next few years. This is expected to alleviate supply constraints and remove any supply shortfall premium in existing capital cost pricing over time." (ACIL 2008).

These conclusions were based on an analysis of greenfield generation costs for the following technologies:

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

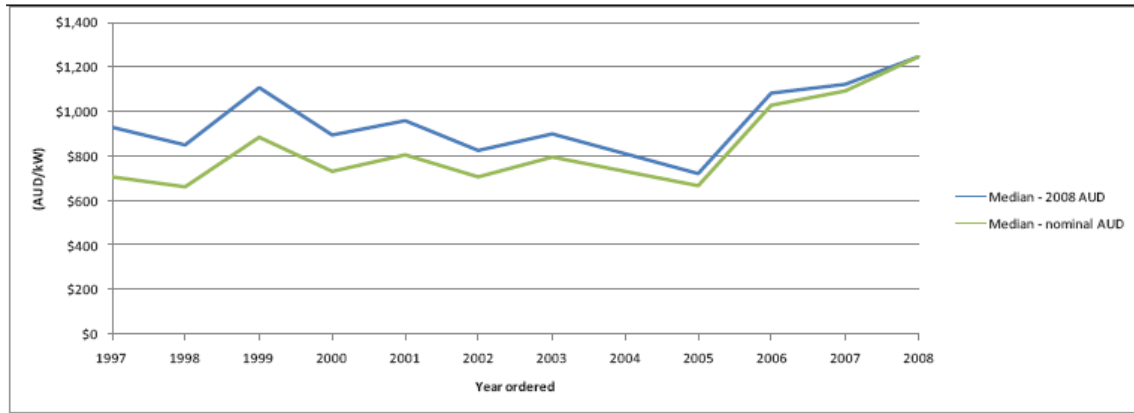
For each technology, ACIL took a bottom-up approach (analysing movements in fuel costs, the cost of generation turbines and their input costs such as steel and labour costs) and used these data to forecast costs in 2009-10.

On the supply side, ACIL concluded that the major turbine manufacturers for both coal-fired and gas-fired generation are in healthy financial positions and capable of expanding production capacity over the next few years. ACIL identified that input costs, particularly steel prices and, to a lesser extent, labour costs have risen sharply over the past couple of years. On the demand side, ACIL identified world economic growth, growth in energy demand, the age of the generator fleet and environmental concerns as the key factors affecting demand for turbines. ACIL also noted the recent global financial crisis and the potential impact of this on the real economy, such as falling demand and lower input costs, including steel and labour costs.

ACIL produced historical trends of median greenfield project capital costs for the above mentioned generation technologies. The Authority's main interests in this context are in CCGT and coal-fired power stations because, under the BRCI methodology, these technologies supply virtually the total NEM load. The BRCI methodology is based on a hypothetical greenfield plant generation mix. Under the "no CPRS impact" scenario, the least cost generation mix is coal-fired and gas-fired plant. Under the alternative scenarios, virtually the whole of the NEM load is supplied by gas-fired technology because coal-fired technology produces roughly twice the amount of CO₂ emissions and therefore carries a higher carbon cost.

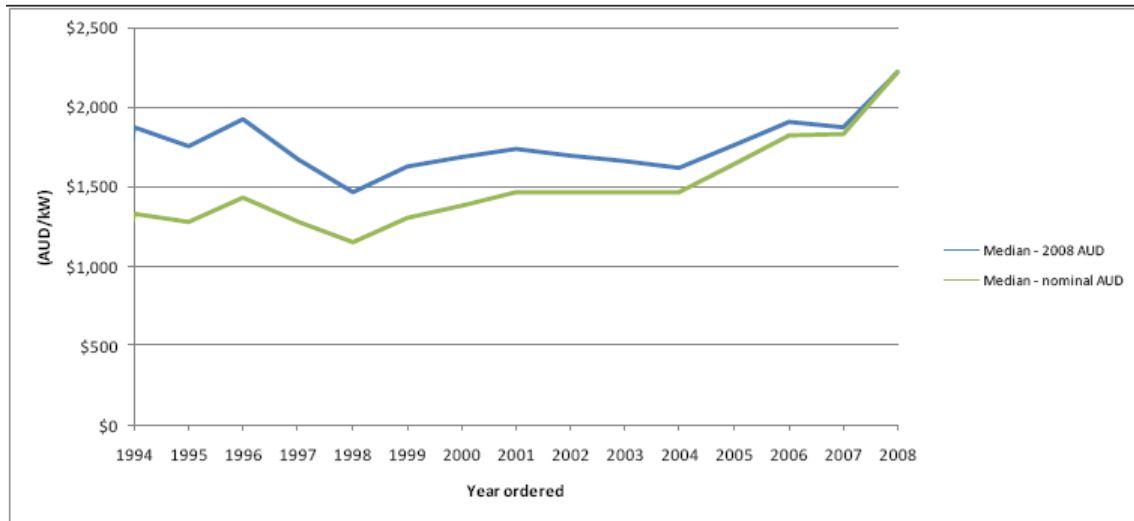
In both cases, a sharp increase in capital costs was evident between 2005-06 and 2007-08. For example, in the CCGT case, real median project capital costs increased from around \$800/kW in 2005-06 to around \$1,200/kW in 2007-08, an increase of 50%. In the case of coal-fired power stations, real median project capital costs increased from around \$1,800/kW in 2005-06 to around \$2,200/kW in 2007-08, an increase of 22% (see Figures 2.1 and 2.2).

Figure 2.1: Median project capital costs (\$A/KW), greenfield CCGT power station, by year of project



Data source: ACIL Tasman modelling.

Figure 2.2: Median project capital costs (\$A/KW), greenfield coal-fired power station, by year of project



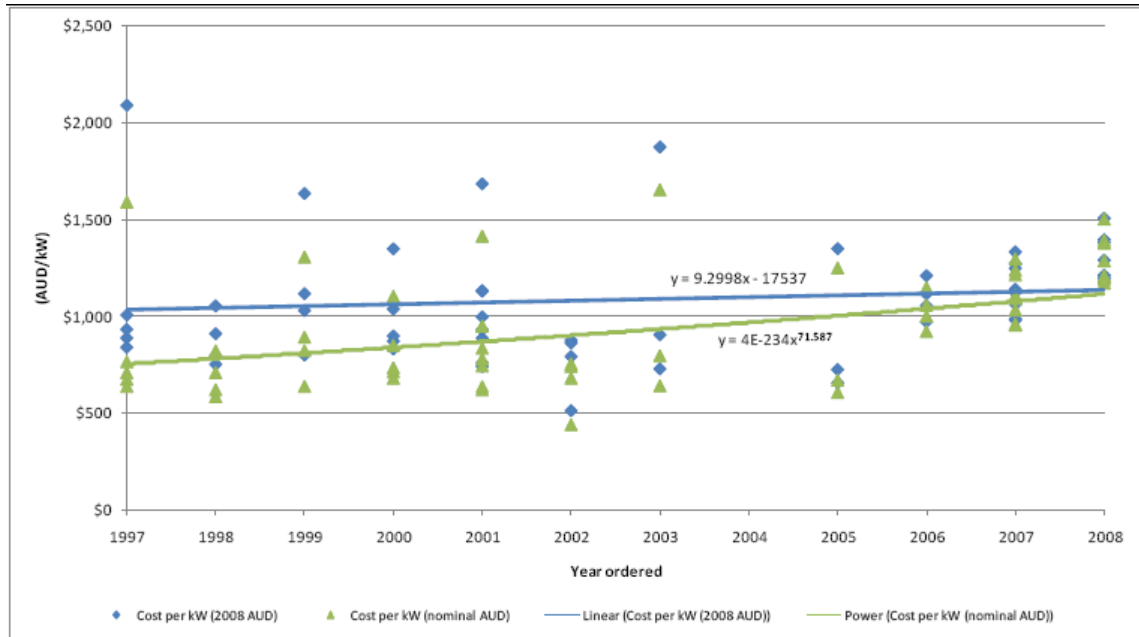
Data source: ACIL Tasman modelling.

ACIL produced projections of capital costs for all generation technologies for the period 2007-08 to 2017-18. In 2009-10, the projected capital costs were \$1,314/kW for CCGT and \$2,291/kW for supercritical black coal (Figure 2.3 below).

ACIL argue that their analysis clearly demonstrates a step-change in energy generation costs and that this limits the usefulness of the regression approach to estimating the LRMC of energy. However, for completeness and comparison, ACIL report the results of their regression analysis in their paper.

ACIL applied regression analysis to a time series of past actual greenfield CCGT generation costs (Figure 2.3) to produce a forecast capital cost in 2009-10. Based on this method of analysis, ACIL forecast that the CCGT cost would be \$1,214/kW in 2009-10 (Table 2.1).

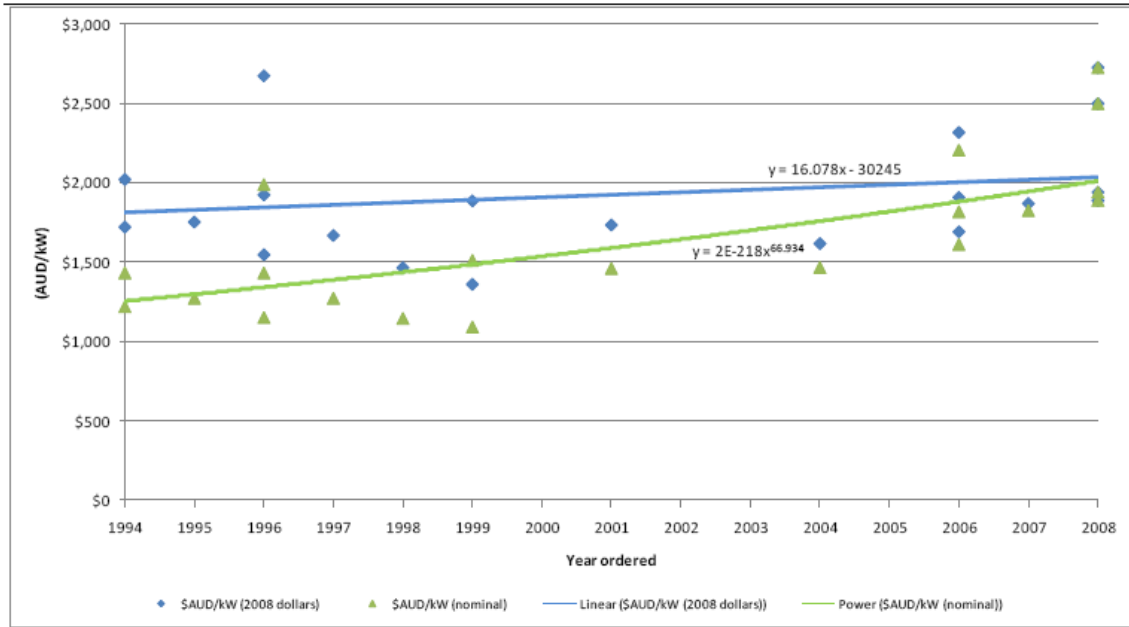
Figure 2.3 Regression results for project capital costs (A\$/kW) for greenfield CCGT by year of project



Data source: ACIL Tasman modelling.

Similarly, ACIL applied regression analysis to a time series of past actual greenfield coal-fired generation costs (Figure 2.4) to produce a forecast capital cost in 2009-10. Based on this method of analysis, ACIL forecast that the coal-fired generation cost would be \$2,177/kW in 2009-10 (Table 2.1).

Figure 2.4: Regression results for project capital costs (A\$/kW) for greenfield coal-fired power station by year of project



Data source: ACIL Tasman modelling.

The results of the two analytical approaches for combined-cycle gas turbine (CCGT) technology and coal-fired technology are shown in Table 2.1 and indicate that, in both generation cases, the step-change forecast of LRMC is higher than the regression forecast of LRMC. For CCGT technology, the step-change forecast yields costs 8.2% higher than the regression analysis. In the coal-fired generation case, the step-change forecast yields costs 5.3% higher than under the regression analysis.

Table 2.1: Technology costs in the NEM, CCGT and black coal-fired generation, 2009-10 (\$/KW)

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

Source: ACIL Tasman modelling.

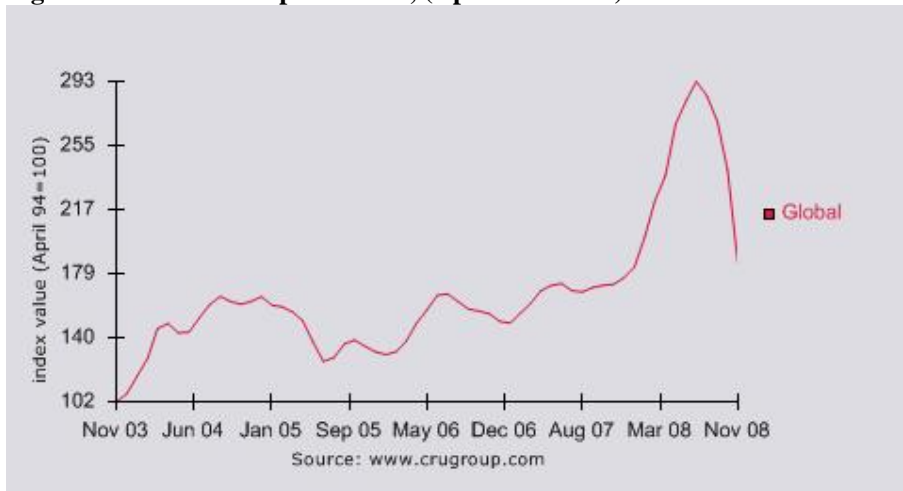
ACIL’s approach to forecasting LRMC in 2009-10 is thorough and the argument that their step-change forecasts of LRMC are better than their regression forecast is internally consistent.

However, the step-change hypothesis remains difficult to prove as only time will tell if the step up in costs will remain a permanent feature of the market or be followed by a step down in costs such that costs in 2009-10 are not reflective of the step-change forecast. A step-change implies a permanent change in the cost path of energy generation. While it is apparent that prices have increased in recent years, this is not conclusive evidence there has been a fundamental step-change in costs rather than the start of a cyclical market movement which will swing back the other way once supply and demand return to equilibrium or move into an excess supply situation.

ACIL does not define the level of increase that would constitute a “step like change” in capital costs nor does it identify a time period over which the increased costs need to occur to be defined as such.

To illustrate the Authority’s concerns regarding the claims that there has been a step-change in costs, Figure 2.5 shows global steel prices since 2003. The figure shows global steel prices have fallen dramatically in the latter part of 2008, from historic highs in mid-2008, as the global prices of coking coal and iron ore (the two main ingredients in steelmaking) declined. In mid-2008, it may well have been credible to suggest that a step change had occurred as prices rose to unprecedented highs. However, the following and equally dramatic fall casts doubt on the step-change hypothesis.

Figure 2.5: CRU Steel price index, (April 1994=100)



Source: CRU (2008), accessed at www.cruonline.crugroup.com

While the approach based on the updated regression analysis would not best reflect a step-change in costs (should this prove to be what has occurred), it does nevertheless capture the change that has occurred, albeit that the outcome is muted by the additional historic data which is included in the data set upon which the analysis is based.

For the purposes of this Draft Decision, the Authority has opted to continue with the (updated) regression approach that was used in the 2008-09 Final Decision. The Authority will consider this issue further before reaching its final decision. One option that could be considered would be to allocate more weight to the recent build up in prices by shortening the time series from (in the case of coal) 15 years down to 10 years. The Authority welcomes further discussion of this issue.

Should account be taken in 2009-10 of the (likely) introduction of the CPRS?

The Australian Government has signalled its intention to introduce a CPRS to apply from 1 July 2010. A White Paper, specifying further design details as well as a 2020 emissions reduction target, is due for release in December 2008. The release of the White Paper should narrow significantly the range of possible carbon pollution permit prices which may apply in 2010-11 and foster greater certainty in terms of understanding the economic impacts.

Alternatively, the White Paper may specify an initial carbon price, for example, \$20 per tonne of greenhouse gas emitted (CO₂-e), for the period up until the end of the Kyoto period in 2012. According to DCC (2008), Australia is on track to meet its Kyoto obligation of achieving not

more than 108% of CO₂-e emissions compared with 1990 levels across the 2008-12 Kyoto commitment period.

In either case, all parties will be better informed of the likely impact of CPRS on notified retail prices in 2009-10 following the release of the White Paper.

However, in response to some initial suggestions in submissions responding to the Interim Consultation Notice and to inform debate on this issue generally, the Authority requested that CRA develop three scenarios estimating the impact of the CPRS on the LRMC of energy in 2009-10, including:

- (a) no CPRS impact;
- (b) a 10% case; and
- (c) a 20% case

The ‘no CPRS impact’ case is one where the introduction of the CPRS on 1 July 2010 has no effect on retailers’ costs in 2009-10. This case does not represent an assumption that the CPRS will not be introduced as scheduled in 2010. Rather, it describes the case where the impacts of the CPRS are not felt in the year before its introduction.

The CPRS 10% and 20% scenarios describe the impact of possible 2020 emissions reduction targets. The 10% scenario refers to a 10% reduction in 2000-level greenhouse gas (GHG) emissions by 2020. Similarly, the 20% case refers to a more onerous 20% reduction in 2000-level GHG emissions by 2020. If implemented, the latter case would generate a higher market price for carbon permits because of the tighter supply constraint, which would in turn increase generators’ costs.

Table 2.2 reports modelled carbon permit prices that CRA has used to estimate LRMC of energy under the two CPRS scenarios. These permit prices were reported in ESAA (2008) and modelled by ACIL for ESAA. In both emissions reduction scenarios, the initial 2010-11 carbon permit price is \$20 (in 2008 dollars).

Table 2.2: Permit prices used in the LRMC modelling, (\$2008/tonne CO₂-e)

<i>Year</i>	<i>10% emissions reduction case</i>	<i>20% emissions reduction case</i>
2009-10	-	-
2010-11	\$20.00	\$20.00
2011-12	\$27.50	\$30.00
2012-13	\$32.50	\$38.00
2013-14	\$37.00	\$42.00
2014-15	\$39.00	\$46.00
2015-16	\$41.00	\$47.50
2016-17	\$42.00	\$50.00
2017-18	\$43.00	\$52.00

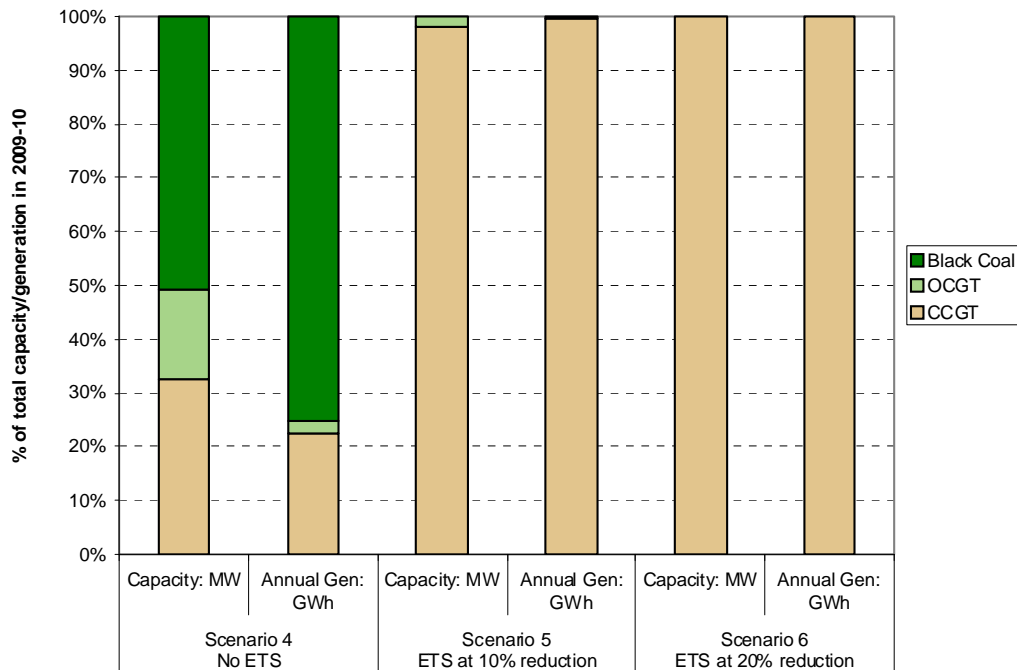
Source: CRA Draft Report, (based on ESAA Report (2008) and ACIL Tasman modelling).

Based on the above permit prices, the estimated LRMC of energy increases under either the 10% or 20% scenarios due to a change in generation mix, which is calculated on a greenfields

basis, as the cost of carbon permits differentially alters the total costs of different generation types, resulting in a different mix of generation technologies than is currently present in the market or in the no CPRS impact case. Under either scenario, there is a substantial swing towards gas.

CRA modelling suggests that, in 2009-10, combined-cycle gas turbine (CCGT) installed capacity and generation increase from 32.6% and 22.5% respectively in the no CPRS impact case, to 98.2% and 100% in the 10% ETS case. Under the 20% scenario, installed capacity reaches 100% as well (see Figure 2.6 below). Such an outcome, which is driven by the greenfields methodology, would be substantially at odds with the current and likely future generation mix, at least in the medium term. In this regard, CCGT currently comprises 8% of installed capacity and generation in Queensland.

Figure 2.6: Share of generation and capacity for Scenarios 4, 5 and 6



Source: CRA modelling.

Depending on the emissions reduction scenario, CRA has estimated that the introduction of the CPRS could result in an increase in the LRMC of energy of between about \$8.00 and \$18.00 per MWh in 2009-10 compared with the ‘no CPRS impact’ case. This cost impost is significant compared with the “no CPRS impact” case. The increase in LRMC from moving from a 10% emissions reduction target to a 20% emissions reduction target is relatively minor. This is because, under the greenfield’s LRMC framework, even the 10% emissions reduction target is enough to switch most of the generation away from coal and towards gas (see Figure 2.6).

Combining CPRS and LRMC modelling scenarios

Combining the three CPRS scenarios (no impact, 10% case, 20% case) and the two capital cost options (step-change and regression analysis) generates six LRMC modelling scenarios as shown in Table 2.3.

The first three scenarios adopt ACIL's step-change cost forecasts and the second three scenarios use the costs based on the updated ACIL trend regression forecasts.

Scenarios 1 and 4 combine the two cost options with the 'no CPRS impact' case which assumes that the introduction of the CPRS on 1 July 2010 has no effect on retailers' costs in 2009-10. The increase in LRMC is reasonably similar under either scenario.

Scenarios 2 and 5, combine the two cost options with the 10% CPRS target while scenarios 3 and 6 introduce the 20% CPRS targets. In all four scenarios, the forecast increase in the LRMC of energy is significantly greater than under scenarios 1 and 4.

Table 2.3: LRMC modelling scenario results, 2008-09 to 2009-10, (\$/MWh)

<i>Scenario</i>	<i>2008-09 (\$/MWh)</i>	<i>2009-10 (\$/MWh)</i>	<i>% change in LRMC</i>
Scenario 1: Step-change cost with no CPRS impact	\$42.61	\$54.12	27
Scenario 2: Step-change costs with 10% CPRS target (in 2020)	\$42.61	\$68.92	62
Scenario 3: Step-change costs with 20% CPRS target (in 2020)	\$42.61	\$71.96	69
Scenario 4: Updated regression analysis costs with no CPRS impact	\$42.61	\$53.42	25
Scenario 5: Updated regression analysis costs with a 10% CPRS target (in 2020)	\$42.61	\$58.78	38
Scenario 6: Updated regression analysis costs with a 20% CPRS target (in 2020)	\$42.61	\$61.64	45

Source: QCA (based on CRA and ACIL Tasman modelling).

The Authority's position

The prospect of an emissions trading scheme as a determinant of the purchase cost of energy was raised in consideration of the 2008-09 BRCI. At that time, there was support from some retailers to increase the BRCI to account for estimated increases in energy purchase costs but not LRMC.

However, the Authority considered (along with some other stakeholders) that, given there was substantial uncertainty about emissions trading, there was no firm basis for including potential impacts of greenhouse emissions schemes in the BRCI at that time.

Although the Australian Government's CPRS policy and design development has moved forward over the intervening period, there are still reasons to be cautious about the likelihood of the Government adhering to its stated introduction timeframe of 1 July 2010. While the CPRS is set to commence in 19 months, no legislation or institutional architecture, let alone an emissions reduction target, has been established.

There are risks associated with bringing to account potential changes in costs before the actual introduction of the CPRS. If the prospective CPRS is accounted for in the BRCI but not reflected in the actual costs retailers face during 2009-10, this will result in customers being overcharged (relative to the costs actually incurred by the retailer).

For this reason, the Authority has decided to not take account of the impact of the CPRS on the LRMC of energy for 2009-10.

Based on CRA's modelling, adopting the regression analysis approach to estimating input costs and excluding any impact from the CPRS, the LRMC of energy in Queensland is estimated to increase from \$42.61/MWh in 2008-09 to \$53.42/MWh in 2009-10, an increase of 25%.

The substantial increase in LRMC stems from the fact that, for the purpose of calculating the BRCI, the legislation requires that LRMC should be based solely on the previous year's load and on the "most efficient combination of generating plant" to meet that load, regardless of the current plant configuration. The Authority is of the view that this requires the LRMC to be calculated using a stand alone or greenfields approach to determining the mix of generation.

As a result, LRMC is quite sensitive to changes in input costs. According to independent expert advice that the Authority has used for the purpose of this Draft Decision, input costs have increased significantly over the last two years.

The Authority will give further consideration to this issue prior to releasing its Final Decision in March 2009.

Purchase Cost of Energy

The Electricity Act requires that the cost of energy in a particular year must reflect the Authority's view of the likely total cost of purchasing energy to supply the NEM load of Queensland in that year. While the Electricity Act obliges the Authority to take account of its latest estimate of the LRMC of energy in the part of Queensland connected to the national grid, the Authority has a discretion to also take account of the actual cost of purchasing energy in the State in that year. In this regard, in the short-run, actual energy purchase costs incurred by a retailer will almost certainly differ from the LRMC of energy because of factors such as supply-demand imbalances and pre-existing hedge portfolios.

CRA's method involved:

- (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.

CRA assumed that the representative retailer would spread its purchases for a single year in the future evenly over the preceding two years. While CRA recognised that this period would vary across retailers depending on their own risk assessments and the degree of certainty over customer loads, it considered that such an approach, while likely to be a simplification of retailers' actual purchasing strategies, would generally reflect the cost of purchasing electricity in the market.

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. However, 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.

A number of issues related to the modelling of energy purchase costs were discussed with stakeholders in the workshops hosted by the Authority. Many of these issues were largely resolved following the workshops as the Authority worked through issues with CRA and stakeholders. Some of the key issues discussed included:

- (a) weighting of price/settlement runs;

- (b) hedging strategy;
- (c) NEM load/load shape; and
- (d) role and application of Marginal Loss Factors (MLFs) in the NEM.

Based on CRA's modelling, the purchase cost of energy in Queensland is estimated to increase by 8% from \$52.91/MWh in 2008-09 to \$57.34/MWh in 2009-10. As a result, the total cost of purchasing energy is expected to rise from \$979.9 million in 2008-09 to \$1,044.6 million in 2009-10, an increase of 7%.

Weighting of the LPMC and the Purchase Cost of Energy

In the Interim Consultation Notice, the Authority canvassed the views of stakeholders regarding the weighting that should be given to the change in the LPMC of energy versus the change in the purchase costs of energy.

Views provided in submissions were once again mixed with a general, in-principle, preference among retailers for a heavier weighting towards purchase costs and a preference among consumer representatives for a heavier weighting towards LPMC. However, several parties acknowledged that, at least in the short-term, the 50/50 weighting was reasonable.

While there were aspects of the arguments in both cases that had merit, none were convincing enough to prompt the Authority to change its approach from the equal weighting given to both energy costs elements adopted in the 2008-09 Final Decision. The Authority has in the past expressed a preference for a higher emphasis on LPMC as this appears more consistent with the current legislation, but has also acknowledged that the current restrictions on the calculation of LPMC is of concern. The Authority has also acknowledged that other jurisdictions tend to use purchase costs rather than LPMC, but this is not an option available to the Authority under the current arrangements.

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 13% gas scheme under the Electricity Act and the MRET scheme established under the Renewable Energy (Electricity) Act 2000.

The costs to retailers of complying with the 13% gas scheme has been estimated using the penalty price to retailers for not surrendering sufficient Gas Electricity Certificates (GECs) 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 13% gas scheme was \$2.29/MWh in 2008-09 and \$2.39/MWh in 2009-10. Therefore, the total cost of the 13% gas scheme was expected to rise from \$84 million in 2008-09 to \$87 million in 2009-10, an increase of 3.6%.

Since the 2008-09 Final Decision, the Council of Australian Governments (COAG) has announced a commitment to combine state-based MRETs 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 MRET/NRET to energy costs, CRA has adopted the same methodology for this year's draft decision as used last year.

To determine the costs to retailers of complying with the MRET scheme, weekly market prices for RECs published by the Australian Financial Markets Association (AFMA) were used. Based on this approach, it was estimated that the allowance for complying with the MRET scheme increased from \$1.35/MWh in 2008-09 to \$1.91/MWh in 2009-10. Overall, the total

cost of the MRET scheme was expected to rise by 40% from \$50 million in 2008-09 to \$70 million in 2009-10. This significant increase is driven by an estimated ramp-up in the required proportion of renewable energy purchased (the so-called RPP) 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.

The Authority also accepted advice from CRA that NEM participant fees and ancillary services charges paid by retailers should be counted in arriving at a final estimate of the cost of energy component of the BRCI. 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.

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 expects the cost of NEM fees, once growth in retail activity is 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 last 52 weeks ancillary services costs data. This framework is unchanged from that used in the 2008-09 Final Decision. On this basis, the Authority accepts the CRA estimate that the cost of ancillary services will decrease from \$0.39/MWh in 2008-09 to \$0.37 in 2008-09. In total, the cost of ancillary services is expected to fall by almost 7% from \$14.5 million to \$13.5 million in 2009-10.

Total Cost of Energy

As noted in the preceding sections, the Authority has decided that an LRMC of energy based on trended capital costs and with no CPRS effects, in combination with purchase costs and other energy costs, best represents the likely total energy costs to be met by retailers in 2009-10.

On this basis, it is estimated that the total cost of energy will rise from \$1,930 million in 2008 09 to \$2,199 million 2009-10, an increase of 14% as shown in Table 2.6.

Table 2.6 Changes in the Cost-of-energy Components from 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>	
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:					
	<i>\$/MWh</i>	52.11		60.36	16
	<i>\$m</i>	1,930		2,199	14

Source: CRA and ACIL Tasman modelling.

3. 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, 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 include the pass through of costs for additional capital expenditure and FRC for Energex and the pass through of costs incurred by Ergon Energy in response to Severe Tropical Cyclone Larry. In addition, adjustments have been made to account for the exclusion of non-distribution use of system (non-DUOS) services from the distributors' revenue caps.

The Authority has based its assessment of transmission network costs on the Australian Energy Regulator's (AER's) Final Decision on Powerlink's revenue cap for 2007-08 to 2011-12 and transmission related costs that the distributors pass through to customers.

On this basis, the Authority has calculated the relevant network costs to be \$2,131 million for 2008-09 and \$2,354 million for 2009-10, an increase of 10.5%.

3.1 Background

The transportation of electricity from generators to consumers requires the use of both transmission networks and distribution networks. Transmission networks transport electricity at high voltages across the State (and from interstate) while 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 costs for larger customers can vary significantly depending on the pattern of their electricity use and their location.

The costs which are included in the BRCI for the transmission component of the total network costs are an estimate of the amount that Queensland's main transmission entity (Powerlink) is expected to charge Queensland's electricity distributors (Energex and Ergon) for using its services.

Estimated transmission costs are based on the AER's *Final Decision on Powerlink's revenue cap for 2007-08 to 2011-12*. These costs are paid by Energex and Ergon Energy on behalf of customers and then passed on to those customers by the distributors.

Distribution costs are based on the Annual Aggregate Revenue Requirements (AARRs) which were originally calculated by the Authority in its *Final decision: Regulation of Electricity Distribution (April 2005)*. The AARRs have been amended to reflect a number of adjustments which were subsequently 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 decision: 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: Ergon Energy's cost pass-through application for Cyclone Larry (September 2008)
<http://www.qca.org.au/files/E-CPT-QCA-TropCycLar-1008.pdf>
- Final Decision: Energex's FRC Pass-through Application (November 2008)
<http://www.qca.org.au/files/E-CPTA-QCA-FINALReport-FRCenergex-1108.pdf>

3.2 Legislative Requirements

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

3.3 Submissions from Stakeholders

The Authority is not required to consult on the network cost component of the BRCI. However, due to the significance of this component in terms of the final BRCI, the Authority sought stakeholder views on network issues relevant to the BRCI in its Interim Consultation Notice.

AGL (2008a) and Energy Australia (2008) supported the approach to estimating transmission costs for 2009-10 as suggested by the Authority in its Interim Consultation Notice.

AGL (2008a,b) suggested that the estimate of transmission costs for 2009-10 would need to take account of the significant decline in retailers' margins that AGL believed would occur due to the impact of the 11 March 2008 Certificate of Delegation and the relatively high rates of growth in network prices for Energex's small customers.

AGL (2008a,b), Integral Energy (2008b) and Origin Energy (2008a) requested additional consultation and clarification on the method for calculating transmission costs and a commitment by the Authority to use any 'forecast' figures for transmission costs in 2009-10 BRCI in the following years BRCI and not update the BRCI using 'actual' costs.

Energy Australia (2008) and AGL (2008b) suggested the Authority should check the extent of any divergence between its estimate of transmission costs for 2009-10 and actual AER-approved transmission costs early in 2009 and recalculate the network cost component of the BRCI if the divergence is significant.

AGL (2008a,b), Energy Australia (2008), Integral Energy (2008a,b) and Origin Energy (2008a) and Queensland Electricity (2008) all emphasised the need for accuracy and transparency in determining network costs for the BRCI.

AGL (2008a), Australian Power and Gas (2008), Energy Australia (2008) and Integral Energy (2008a,b) noted that the current BRCI method masks relatively high rates of growth in network prices for small customers which caused retailers' margins to decline. Australian Power and Gas and Energy Australia suggested that this issue could be addressed by removing network costs from the BRCI. The suggestion was made by some stakeholders that, to account for variations in cost between customers, network charges should instead be treated as a cost pass through or be applied on a locational basis. Integral Energy suggested the Authority should address the issue in its role as the regulator of network services.

Origin Energy (2008a) expressed an ongoing concern that the adjustments made to incorporate additional capital expenditure by Energex, after smoothing, may distort the BRCI and that the impact of this was not clear from the information provided to date.

AGL (2008a,b) suggested the Authority should re-smooth the AARRs that resulted from the pass through of additional capital expenditure by Energex because the original re-smoothing incorporated an adjustment for the previous over-recovery of revenue that had not been factored into the calculation of the BRCI.

AGL (2008a) and Origin (2008a) both requested that the Authority provide additional information on network costs to enable stakeholders to undertake a more thorough review.

A number of submissions raised issues relating to the impact of aspects of the network component calculation required by the legislation on margins and headroom. These issues are discussed in the following sections.

3.4 The Authority's Position

The Electricity Act requires the Authority to base the network cost component of the BRCI on the annual revenue requirements of transmission network service provider (Powerlink) and distribution network service providers (Energex and Ergon Energy) in Queensland.

Suggestions by some stakeholders to exclude part or all of network costs from the calculation of the BRCI are 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.

Distribution costs

In this Draft Decision, the Authority has applied the same approach to setting the distribution cost component of network costs as it used in making its decision for 2008-09. Consistent with that approach, the starting point is taken as the original AARRs' the Authority set for Energex and Ergon Energy in its *Final decision: Regulation of Electricity Distribution* (April 2005).

These have then been adjusted, as shown in Table 3.1, to reflect a number of subsequent adjustments explained in detail in the 2008-09 BRCI Decision 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 (additional capital expenditure (capex) and FRC for Energex and Cyclone Larry for Ergon Energy).

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. The combined impact of these relatively minor adjustments is shown in Table 3.1.

Removal of Non-DUOS Services

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-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 from the distributors' AARRs the operating and capital costs associated with providing excluded distribution services.

Mt Isa Network Costs

For the Draft Decision, the Authority has excluded Mt Isa network costs from the calculation of BRCI network costs for consistency with its calculation of the national electricity market (NEM) load. This is the same approach as was adopted in calculating the 2008-09 BRCI.

Energex – Capex Pass Through

In March 2007, the Authority approved the pass through of an additional \$720 million of capex by Energex (QCA, 2007c). The impact of this decision on Energex's 2008-09 AARR and 2009-10 AARR is shown in Table 3.1.

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 Decision allows Energex to raise an additional \$30 million of revenue in 2009-10.

Ergon Energy – Cyclone Larry Cost Pass Through

In September 2008, the Authority approved the pass through of capital costs of \$6.7 million and operating costs of \$7.9 million incurred in 2005-06 by Ergon Energy in response to Cyclone Larry (QCA, 2008a), the revenue impacts of which were \$5 million in 2008-09 and \$5.8 million in 2009-10, as presented in Table 3.1.

Under- and Over-Recovery of Revenue

Consistent with its approach in calculating the BRCI for 2008-09, the Authority has not adjusted the distributors' revenue requirements for the annual under- or over-recovery of revenue for the purpose of calculating the BRCI.

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. As a result, any under- or over-recovery of revenue does not

reflect a change in the level of underlying costs and revenue requirement that has been approved for the distributor. Over time, unders and overs will net each other out.

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 has based its estimate of transmission revenue requirements on the transmission use of system (TUOS) charges that Powerlink levies on Energex and Ergon Energy, and which the distributors pass through to customers. As the charges for 2009-10 are not available for this Draft Decision, the Authority has estimated the TUOS charges that Powerlink is expected to levy on Energex and Ergon Energy during 2009-10 by applying the percentage share of Powerlink's 2008-09 revenue cap accounted for by TUOS charges 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*. This estimate will be updated for the Final Decision.

In addition to Powerlink charges, 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 is reflected in the TUOS charges calculated by the distributors for pass-through to distribution customers.

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

The transmission costs that are expected to be passed through to customers by Energex and Ergon Energy in 2009-10 are presented in Table 3.1.

3.5 Network Costs

The following table provides a summary of how the distribution and transmissions network costs have been calculated.

Table 3.1 Adjustments to Revenue Requirements for Distribution and Transmission Network Services in Queensland (\$m) – Draft Decision

Energex	2008-09	2009-10	% change
Original AARRs ¹	879.6	927.9	5%
Minor AARR adjustments ²	(9.6)	(11.6)	21%
Capex cost pass-through	8.5 ³	73.5 ³	762%
FRC cost pass-through	15.0 ⁴	30.0	100%
Revenue from non use-of-system services	(18.5)	(19.5)	5%
Adjusted revenue	875.0	1000.3	14.3%
Ergon Energy	2008-09	2009-10	% change
Original AARRs ⁵	812.5	860.4	6%
Minor AARR adjustments ⁶	1.5	2.2	47%
Revenue from non use-of-system services	(7.4)	(7.6)	3%
Mt Isa costs	(9.8)	(10.4)	6%
Cyclone Larry cost pass-through	5.0	5.8	16%
Adjusted Revenue	801.8	850.4	6.1%
Powerlink	2008-09	2009-10	% change
Maximum Allowable Revenue ⁷	595.9	661.4	11.0
TUOS Cost Pass Through for Energex and Ergon Energy⁸	454.3	503.2	10.8
Total Revenue/Network Costs	2,131.1	2,353.9	10.5

1, 5 QCA, 2005.

2, 6 Includes adjustments for updated opening asset bases for Energex and Ergon Energy, and, for Energex, correction of minor errors made in setting the AARRs.

3 QCA, 2007c.

4 QCA, 2008d.

7 AER, 2007.

8 Calculated to pass through Powerlink charges, avoided TUOS payments to embedded generators and payments to other distribution network service providers. Does not include adjustments by Energex and Ergon Energy for previous under or over-recovery of TUOS revenue. As the charges for 2009-10 are not yet available, for this Draft Decision the Authority has estimated the TUOS charges that Powerlink is expected to levy on Energex and Ergon Energy during 2009-10 by applying the percentage share of Powerlink's 2008-09 revenue cap accounted for by TUOS charges to Powerlink's 2009 10 revenue cap.

Note Totals may not add due to rounding.

4. 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.

Consistent with its approach to calculating the 2008-09 BRCI, the Authority estimated retail operating costs for 2009-10 by escalating the retail costs established in the 2008-09 BRCI to reflect price inflation and wages growth. Costs relating to customer acquisition and retention are forecast to increase by 3.2%. Retail operating costs (excluding customer acquisition and retention costs) are expected to increase by 6.1%. In total, retail operating costs are expected to increase by 5.4%.

The Authority has maintained the retail margin at 5% on the basis that it should provide a reasonable return to a retailer for the risks that it faces and has not changed since last year.

Based on total customer numbers supplied by Energex and Ergon Energy, total retail costs, including the retail margin, are expected to increase from \$432.2 million in 2008-09 to \$469.9 million, a rise of 8.7%.

4.1 Background

Retail operating costs relate to the services provided by a retailer to its customers excluding those costs simply passed through to consumers, such as the costs of purchasing energy and network costs. Typically, retail operating costs include: customer administration (including call centres), billing and revenue collection, IT systems and regulatory compliance. Costs associated with metering and data services may also be included in retail operating costs if not already included in distribution charges. Customer administration and billing generally account for over half of retail operating costs.

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

4.2 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.

4.3 Submissions from Stakeholders

In its Interim Consultation Notice, the Authority sought stakeholder views and supporting arguments in relation to possible changes in retail costs, retail margin and factors affecting churn rates between 2008-09 and 2009-10. The Authority also sought comment on any other issues that it should consider in estimating retail costs.

Retail Operating Costs

AGL (2008a), Origin Energy (2008a,b,d) and Integral Energy (2008b) supported the retail benchmarking approach that the Authority used to estimate retail operating costs in the 2008-09 BRCI Final Decision.

However, AGL (2008a), APG (2008) and Origin Energy (2008a,b) suggested that the Authority did not make sufficient allowance for increased risk in the 2008-09 BRCI and that higher working capital costs needed to be adequately captured in future BRCI decisions. AGL and Origin Energy proposed that the increase in risk and working capital costs could be included by either an increase in retail margin or a higher allowance for operating and wholesale energy costs. Both retailers suggested that this would require a clear understanding of the relationship between retail costs and retail margin when determining the 2009-10 BRCI.

Integral Energy (2008a) suggested that customer acquisition costs and variations in the cost of providing customer retail services to different customer segments continue to place upward pressure on retail costs.

Origin Energy (2008a) and AGL (2008b) suggested that retail operating costs had been underestimated, in part because the higher costs of serving larger customers had not been taken into account. However, Origin also acknowledged that, in the BRCI context, the change in costs was more significant than the estimate of total costs.

APG (2008) and Ergon Energy (2008) suggested that the introduction of the Carbon Pollution Reduction Scheme (CPRS) in 2010 would have an impact on retail operating costs and margins in 2009-10 and should be taken into account in calculating the 2009-10 BRCI. APG (2008) suggested that the 2009-10 BRCI calculation should ensure that retail electricity tariffs are set at cost reflective levels to stimulate investment in the electricity market, promote competition and reduce any price shock from the introduction of emissions trading.

Customer Acquisition and Retention Costs

Origin Energy (2008d) suggested that, at face value, the method of escalation and use of 2008-09 forecasts are reasonable until further information is available. However, Origin Energy did not agree with the Authority's decision in 2008-09 to re-estimate the 2007-08 customer acquisition cost component using revised churn numbers. In response to this latter point, the Authority notes that the estimation of customer acquisition and retention costs in 2007-08 was not based on churn rates for Queensland.

AGL (2008a) suggested that the churn figures estimated by the Authority in 2008-09 were too low and that a churn rate considerably higher than 10% (as evidenced in the South Australian and Victorian markets) was needed if the retail margin was to be maintained in 2009-10. AGL (2008a) proposed that the Authority determine churn rates for 2009-10 recognising the requirement in the delegation to maintain retail margin. TRUenergy (2008b) indicated a preference that churn be based on observed market transfer rates in other competitive jurisdictions. This position was supported by Integral Energy (2008b), AGL (2008a,d) and Queensland Electricity (2008).

However, the Authority notes that the legislation requires that retail costs must reflect the Authority's view of the likely cost of providing retail services to Queensland customers and the levels of churn in other jurisdictions, which may be at a very different stage in the development of a competitive market, is not relevant in that context.

TRUenergy (2008a,b,c) noted that the current approach to separating out customer transfers from notified prices to market contracts with the same retailer failed to recognise costs associated with customer transfers from one market contract to another with the same retailer.

Integral Energy (2008a,b) argued that retail acquisition costs should reflect the costs faced by a second-tier retailer rather than an incumbent. Integral Energy (2008c) also suggested that, if historic data on customer switching is to be used, it should be reflected as a percentage of the customer base to capture growth in customer numbers from one year to the next.

Queensland Electricity (2008) argued that underestimated acquisition costs and low switching rates in the BRCI would suppress competition and thus be self-fulfilling.

Retail Margin

APG (2008), Origin (2008) and Energy Australia (2008) all considered that the 5% margin for 2008-09 was too low.

Origin Energy (2008a,b,d) suggested that the assumption of a constant margin was no longer valid and that the retail margin for a retailer investing in the Queensland market needed to change in 2009-10 to reflect the regulatory, price and investment risks that have become apparent. Origin Energy proposed that the risks associated with an early Final Decision for the 2009-10 BRCI in December 2008 (as initially proposed) should also be explicitly recognised in the retail margin.

Energy Australia (2008) was of the view that the 5% retail margin applied in 2008-09 did not adequately reflect the risks or costs faced by retailers in a volatile wholesale market and the use of LRMC in setting energy costs. This position was supported by Queensland Electricity (2008).

4.4 The Authority's Position

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

Components of total retail operating costs were calculated using the expected cost per customer and applied to the NEM load of the State.

Retail Operating Costs

In calculating the retail operating costs, the Authority has continued to apply the benchmarking approach adopted in 2008-09. This approach was broadly supported in submissions.

While alternate approaches identifying costs for different customer groups might produce more robust estimates of retail operating costs by customer group (as noted in several submissions), CRA, in its advice for the 2009-10 BRCI, indicated that reliable information on segmentation of the customer base and data on the individual components of operating costs was still not readily available and therefore a 'bottom-up' approach to calculating retail operating costs remained impractical.

In calculating the BRCI for 2007-08, the Authority estimated retail operating costs for 2006-07 based on benchmark comparisons of overall retail costs in other jurisdictions. This level of cost was then escalated for 2007-08 to reflect higher labour costs, additional costs expected to be incurred by a retailer due to the introduction of FRC and costs relating to customer acquisition and retention.

For the 2008-09 BRCI, the Authority has decided to continue with the benchmarking approach proposed by CRA given the limited availability of relevant data and the fact that retail costs make up a relatively small proportion of the BRCI. Continuation of this approach was broadly supported in submissions.

For 2009-10, the Authority has again decided to estimate retail operating costs by escalating the benchmark established in 2006-07 to account for inflation and wages growth in the intervening period. On this basis, forecast retail operating costs were estimated to be \$84.03 per customer in 2009-10, representing a 3.8% increase on the 2008-09 figure (\$80.96) reported in the Authority's 2008-09 Final Decision.

Customer Acquisition and Retention Costs

Customer acquisition costs attracted significant comment in submissions in response to the Authority's Interim Consultation Notice. There was concern that the level of churn in 2008-09 had been underestimated and that this would make it difficult to maintain retailer headroom in 2009-10. The general question of maintaining retailer headroom is considered in chapter 6.

In calculating the BRCI for 2008-09, the Authority accepted CRA's advice on customer acquisition costs, which were calculated (in 2007-08 dollars) at \$171.43 per customer changing retailer and \$100.00 per customer transferring to a market contract with the same retailer.

CRA estimated acquisition costs for 2009-10 by escalating these 2007-08 values by the weighted average of price and wage inflation in 2007-08 and 2008-09 to arrive at customer acquisition costs in 2009-10 of \$183.67 per customer for those switching between retailers and \$107.14 per customer for those transferring from notified prices to a market contract with the same retailer.

In terms of customer churn rates, CRA has advised the Authority that, due to the difficulties it is having in analysing NEMMCO data to identifying customers switching between market contracts with the same retailer without picking up spurious results, it has, for the purposes of this Draft Decision, elected to use the same switching and transfer numbers (i.e. number of people switching and transferring) for the 2009-10 BRCI as it had used in the 2008-09 calculation. That is, switches from retailer-to-retailer are estimated to be 282,144 and transfers to a market contract with the same retailer are estimated to be 158,275. CRA will revise these calculations for the Final Decision once more data becomes available.

Based on the above approach, CRA has estimated that total customer acquisition and retention costs increased from \$51 million in 2008-09 to \$53 million in 2009-10.

Retail Margin

There are various ways a retail margin may be defined and measured. A retailer's gross margin could be defined as the difference between retail revenue and the total cost of energy and network services, while the net margin could be defined as that which remains after the retailer's operating costs are subtracted from the gross margin. In this Draft Decision, the Authority is referring to the net margin in discussing 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.

In determining an appropriate retail margin, CRA benchmarked the margins accepted by regulators in other jurisdictions which ranged from 2% to 8%. The 5% margin selected for inclusion in the BRCI was around the mid-point of this range. CRA considered this rate to most appropriately account for the volume and price risks faced by retailers in the Queensland market.

In order to determine whether the retail margin should be changed in 2009-10 from the previous year, CRA considered what, if anything, had changed between 2008-09 and 2009-10 in the risk profile of the retailer that is considered in the BRCI framework. CRA concluded that there has been no particular change in characteristics of the retailer.

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

The Authority remains of the view that a retail margin of 5% should provide a reasonable return to a retailer for the risks that it faces. The Authority acknowledges the point made by both AGL and Origin that a clear understanding of the relationship between retail costs and retail margin is important when determining the 2009-10 BRCI. Given that 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 margin is appropriate. If all other costs components are addressed correctly, then the retail margin should not need to change across the reference period.

Whilst this was not the view of some retailers, the Authority finds no strong evidence that a reasonable margin sought by retailers would be materially different from that applicable to the Queensland market in 2008-09. Chapter 6 includes some discussion on the issue of maintaining headroom and this may also go some way to addressing the concerns expressed in some submissions regarding the retail margin.

On this basis, the retail margin remains 5%, equating to \$432 million in 2008-09 and \$470 million in 2009-10. As the retail margin (in percentage terms) is assumed not to vary from 2008-09 to 2009-10, the size of the retail margin will have no impact on the change in the BRCI between these two years.

In summary, the costs of providing retail services in this Draft Determination are reported in Table 4.1.

Table 4.1: 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 (\$/customer)</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 and margin	432.2	469.9	8.7

Note: Numbers may not add due to rounding.

5. ELECTRICITY LOAD

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

As the 2009-10 BRCI Draft Decision has to be calculated by 1 December 2008, part of the NEM load for 2008 must be forecast. Actual market data for the full 2008 calendar year will be available for inclusion in the Final Decision to be released by 1 March 2009.

For the purpose of arriving at a c/kWh measure of costs, the relevant NEM load (the denominator) is the load which flows through the transmission network to the distribution networks of Energex and Ergon Energy plus the output of some relatively large generators embedded in the Energex and Ergon Energy networks that participate in the NEM.

The NEM load for this purpose does not include customers connected to isolated distribution systems not participating in the NEM (such as the Mt Isa network load) or the loads of small generators embedded in the distribution networks of Energex and Ergon Energy that do not participate in the NEM.

Customers that are directly connected to the transmission network and load flowing to Country Energy's network in New South Wales are also excluded from this calculation of the NEM load. In its latest advice, Powerlink has identified that, in previous years, it has failed to identify one directly connected transmission customer. To correct for this error, the Authority will, in its Final Decision, remove this customer from both 2007 and 2008 NEM load data. In the time available, it has not been possible to redraft the Draft Decision on this basis and the Authority has instead left the particular customer in both sets of NEM load data. This increase in the BRCI that results from this decision is consistent with that which would have resulted from removing the data from both years.

On this basis, the Authority has determined the relevant NEM load of Queensland to be applied in calculating the BRCI as 37,040 GWh in 2007 and 36,437 GWh in 2008, a decrease of 1.6%.

5.1 Background

In the preceding chapters, the cost components of the BRCI have been considered. In order to determine the unit cost of electricity, the quantity of electricity consumed (the load), must also be determined.

5.2 Legislative Requirements

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

The Queensland NEM load is to be calculated according to the Authority's view of the total of the loads for Queensland supplied at each transmission connection point to the distribution networks of Ergon Energy and Energex. Isolated distribution networks and customers directly connected to the transmission network are to be excluded from the Queensland load.

5.3 Submissions from Stakeholders

While a number of submissions raised issues concerning load in relation to the calculation of the energy cost component of the BRCI, as discussed in Section 2, only AGL (2008a) and Origin Energy (2008a) commented on the load to be used as the denominator in the BRCI calculation.

Origin Energy (2008a) noted that the (original) December 2008 deadline for finalising the 2009-10 BRCI would increase the level of forecast error in the estimate but that the impact of this would be eliminated if the Authority elected not to update its estimate in the following year. Origin Energy suggested that the Authority should not amend the estimate of the NEM load it used to calculate the BRCI for 2008-09. Origin Energy also suggested that the Authority should use a more robust forecast method for estimating the NEM load and conduct a transparent consultation so that all stakeholders are aware of the method.

In its submission, AGL (2008a) suggested that the NEM load could be forecast by basing total Queensland load on data available from NEMMCO's 2008 Statement of Opportunities³ and removing the loads of customers directly connected to the transmission network based on an extrapolation of existing data.

5.4 The Authority's Position

Relevant Period

The Minister's Delegation requires that the NEM load of Queensland for the relevant tariff year be based on the load for the preceding calendar year.

Relevant NEM Load of Queensland

The legislation requires that the Authority include only that load supplied through transmission connection points to the distribution systems of Energex and Ergon Energy that are connected to the NEM.

As in previous years, data obtained by the Authority from NEMMCO regarding the total NEM load of Queensland included the load of customers directly connected to the transmission network. With the assistance of NEMMCO and Powerlink, the Authority identified these customers and excluded their load from the data.

However, in response to the Authority's request to identify directly connected customers to establish the NEM load for 2008, 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 has also acknowledged that this customer had not been identified as a directly connected transmission customer in previous years. On this basis, the NEM load for 2007 used in the Authority's 2008-09 Decision, and the relevant starting year for this Draft Decision, is higher than it would have been had this TNI been correctly identified. Similarly, excluding this TNI only from the NEM load for 2008 would create an artificial decrease in the NEM load between years of about 2%.

³ The NEMMCO Statement of Opportunities 2008 update had not been published at the time of this decision.

The Authority became aware of this issue late in the process of compiling this Draft Decision and has had insufficient time to redo the calculations for 2008-09 in order to remove this TNI from the load used in that Decision. In order to avoid introducing an artificial reduction in load into the calculation of the 2009-10 BRCI, for this Draft Decision only the Authority has included the load associated with this newly identified directly connected TNI in the NEM load for 2008.

This is a second best solution. For the Final Decision, the Authority will make the more appropriate correction and remove the load associated with this TNI from the NEM load for both 2007 and 2008.

However, the Authority has determined that the inclusion or exclusion from both years has no appreciable impact on the BRCI calculation for 2008-09 or for the current 2009-10 calculations. This is because the BRCI is a measure of change and adding or subtracting a very similar amount to the load in each year has no appreciable impact on the change between years.

A benefit of not making the final correction until the Final Decision is that stakeholders can make direct comparisons between the estimates used in this Draft Decision and those presented in the Authority's 2008-09 Final Decision.

Therefore, for this Draft Decision, the Authority has kept the NEM load consistent across 2008-09 and 2009-10 by keeping the TNI in question in the load for both years. For the Final Decision, the Authority will remove this TNI from the NEM load for both years.

Energy passing through a single connection point relating to Country Energy's network in New South Wales was also excluded from the data on the basis that this load was not supplied to Queensland end users.

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

Data supplied by NEMMCO included loads supplied by registered embedded generators participating in the NEM but excluded loads supplied by unregistered embedded generators⁴.

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 accompanying load profile data. As the Authority was not inclined to guess the load profile that might accompany the loads supplied by unregistered generators (which appeared to account for less than 1.5% of the total load), the Authority decided not to include the loads of unregistered embedded generators in the calculation of energy costs. This is the same approach as the Authority adopted with the 2008-09 BRCI.

For the purpose of this Draft Decision, the Authority has estimated load data for the latter part of 2008 so that it matches the seasonal movements in the 2007 load.

⁴ 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 30MW must apply to NEMMCO for exemption from registering and satisfy certain criteria.

Given the change in deadlines provided by the latest delegation from the Minister, it is now anticipated that full year data for 2008 will be available from NEMMCO in time to be incorporated into the Final Decision on the BRCI.

The Authority's calculation of the NEM load of Queensland for 2007 and 2008 is presented in Table 5.1. In this regard, the Authority calculated that the relevant NEM load of Queensland decreased by 1.6% in 2008 to 36,437 GWh.

The estimated decline in load may seem to be an unusual outcome given that Queensland's population and economy are growing. NEMMCO (2008b) has indicated that the reasons for the decline in load include fewer hot days, the impact of water restrictions on mining output and flooding rains curtailing productive activity.

Table 5.1: Queensland load 2007 and 2008 (GWh) – Draft Decision

	<i>2007</i>	<i>2008¹</i>	<i>% change</i>
Gross NEM load of Queensland	46,727	45,978	-1.6%
Less exclusions	9,687	9,541	-1.5%
NEM load of Queensland	37,040	36,437	-1.6%

1. Load for 13 July 2008 to 31 December 2008 was estimated as described above, based on figures to June 2008.

If the incorrectly identified TNI was removed from the NEM loads for 2007 and 2008 shown in Table 5.1, the load in 2007 would become 36,268 GWh and the load for 2008 would become 35,679 GWh, which still represents a decrease of 1.6% between years.

6. TOTAL BRCI

The method that the Authority has adopted in this Draft Decision to calculate the BRCI for 2009-10 is the same as that employed in the 2008-09 Decision.

Several submissions raised issues of a general nature concerning the BRCI methodology and the Authority's processes and consultation which were not related to the calculation of specific components of the BRCI.

There are also some general issue relating to headroom and reversion of customers to notified prices that are also not specific to the individual components of the BRCI calculation.

These issues are addressed in this chapter.

6.1 Background

While the preceding chapters have considered the specific components of the BRCI calculation, there are a number of general issues which require some further consideration.

6.2 General BRCI Methodology

Several second-tier retailers raised general concerns that their actual positions, and thus the prospects for vigorous market competition, were being adversely affected because the methodology failed to recognise the higher customer acquisition and retention costs that might apply to a new entrant retailer rather than an incumbent.

The Authority's Position: The legislation requires that the Authority consider retail costs in the context of a theoretical incumbent retailer with certain characteristics, such as significant market share and a customer base that reflects the proportions of different customer types in the Queensland market. Whilst this approach will not necessarily reflect the potential higher costs faced by a new entrant retailer seeking to capture a share of the market, this is not a matter of discretion for the Authority. Notwithstanding this, there has also been no evidence presented to show that the year on year change in such costs for new entrants has been higher than that for the theoretical incumbent, and it is the change in costs that is relevant for this Draft Decision not the relative level of absolute costs.

SunWater (2008a), in their response to the release of CRA's draft reports, suggested that the method of annual increases was not providing certainty to users, particularly those that were locked into long term contracts or subject to regulated price paths themselves. SunWater proposed that this be managed by capping the BRCI at the CPI.

The Authority's Position: While such an approach might provide greater certainty and be desirable for such customers, it is not possible under the current legislative framework for the determination of notified prices which is quite specific about the approach the Authority should adopt.

AGL (2008a) and Origin (2008a,b) criticised the Authority's decision to update old forecasts with actual market data when recalculating the BRCI components for the previous year due to a change in methodology (as occurred in 2008-09) on the basis that this compounded the suppression of the BRCI to the detriment of the retail margin.

The Authority's Position: As there has been no change in methodology in this Draft Decision, arguments concerning the use (or not) of the latest available data in undertaking a recalculation do not require comment at this time. However, the Authority did give careful consideration to this issue in arriving at its Final Decision on the 2008-09 BRCI. The Authority also notes that

there is no reason to assume that continued application of this principle would in any particular instance result in a lower BRCI estimate.

A number of submissions expressed concern regarding the need for extended forecasts that would have been required by the early reporting deadlines of the initial Delegation, and the increased risks this would have involved for retailers and consumers.

The Authority's Position: Given the change in timing provided by the Current Delegation from the Minister, these concerns have largely been addressed. With the current 1 March 2009 deadline for the Final Decision, it is anticipated that actual load data for the entire year will be available while the period of pricing that will still need to be forecast should be little different this year to previous years.

6.3 Consultation Process and Transparency

Several submissions, including from AGL (2008a) and Origin Energy (2008a), raised concerns over the level of consultation and transparency in the calculation of the BRCI in current and past consultation processes.

At the same time, a number of submissions, such as Integral (2008a,b), voiced support for, and acknowledgement of, the benefits derived from the additional consultation with industry undertaken by the Authority, particularly via the workshops, opportunities to review the consultant's reports and the Authority's commissioning of additional analysis in response to stakeholder concerns.

The Authority's Position: Consultation is important to stakeholders (and the Authority) as evidenced in many submissions. The aim of the Authority has been to provide as much opportunity for stakeholder input as possible within the available timeframe and, in the case of the 2009-10 BRCI, the Authority has again provided more opportunities for input from stakeholders than is contemplated in the requirements specified in the legislation.

As for transparency, the Authority has provided its reasons for arriving at this Draft Decision in detail and has taken additional steps to provide interested parties with opportunities to discuss and understand the modelling exercise conducted by CRA through the workshops and the release of the detailed reports received from CRA and ACIL Tasman.

6.4 Minister's Delegation

The 26 August 2008 Delegation from the Minister requires that the Authority consider the policy objectives of the Queensland Government relating to the maintenance of retail headroom and preventing retailers incurring a loss where a customer reverts to notified prices. Specifically, the Delegation requires that:

- (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 competition 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.

Maintenance of Headroom

Integral Energy (2008b), AGL (2008a), Origin Energy (2008a) and TRUenergy (2008a) all suggested that the Authority's response to the requirement to maintain headroom in retail prices had been largely ineffective, resulting in an erosion of headroom due to past decisions.

Integral Energy (2008d) and Origin (2008d) suggested the Authority should demonstrate that the policy intent regarding headroom had been met or that the methodology was consistent with the conditions of the Delegation.

Submissions received from retailers, including from AGL (2008a) and Origin Energy (2008a), have generally claimed that retail headroom has been eroded by the previous two BRCI decisions. Some submissions suggested that the BRCI has not accurately reflected the changes in input costs faced by retailers. As such, retailers were concerned that maintaining this methodology for 2009-10 would entrench any deterioration or contribute to further deterioration. Others have suggested that specific elements of the prescribed methodology will inevitably lead to an erosion of headroom. For example, Integral (2008c) suggested that the method of calculating network costs creates a disparity between the BRCI estimate and actual costs which erodes retail headroom.

Integral Energy (2008c) suggested three factors it believed indicate that headroom had deteriorated over time:

- (a) a decrease in the size of discount, relative to the Notified Prices, that retailers are offering customers;
- (b) a decrease in the level of participation by second-tier retailers in the Queensland market; and
- (c) a decrease in customer churn rates.

The Authority's Position: In considering the issue of headroom in its 2008-09 Decision, the Authority noted that it did not have access to reliable information on the actual retail margin of either Origin Energy or AGL in Queensland but considered that, having recognised all known sources of cost increase between years, the existing headroom should have been maintained.

The Authority considers that the most appropriate manner in which to consider headroom is in the context of the total BRCI rather than in the context of each cost component. In other words, if the Authority addresses all of the costs involved in calculating the BRCI then, in theory, retail headroom should not change.

Neither the Electricity Act nor the Regulation refer to 'headroom'. It is therefore not a defined term in the context of the legislation. However, headroom appears to refer to the gap between the competitive cost of supplying customers (including all costs and normal profit) and the notified price. In a competitive market, headroom will be competed away by retailers in the pursuit of market share. In that sense, headroom is not needed in order to ensure an adequate level of profitability, but rather to provide space for retailers to compete by offering non-market customers market contracts at some discount to their current notified price.

The Authority accepts that there are aspects of the prescribed methodology that could potentially result in headroom for retailers (who operate predominantly in the south east of the State) being eroded under the present circumstances. For example, the differing rates of growth in network cost between Energex and Ergon Energy means that, at present, the network component of the BRCI understates the change in costs on the Energex network (which covers most of the area where retailers currently compete) and overstates costs on the Ergon Energy

network. However, whether these conditions are permanent or transient, and whether they will result in retail headroom being other than relatively stable over time, is less clear. Further, the Electricity Act requires the Authority to consider the total revenue requirements of both distributors.

The Delegation refers to maintaining the retail headroom in the tariffs at the time of the Original Delegation. At that date (16 March 2007), there were three retailers operating in the Queensland small customer market: AGL, Origin and Ergon Energy (the retailer, not the distributor). Tariffs at that time reflected a long history of Government decisions on the appropriate level of (uniform) retail tariffs and other policy concerns of Government and did not necessarily reflect the economic cost of supplying electricity, either in total or to particular customers or customer groups. What the level of headroom might have been in the existing tariffs at that time is not clear to the Authority.

As noted above, given the uncertainties surrounding this whole issue, the Authority has in previous decisions assumed that, if all other sources of change in costs have been accounted for as best they can in terms of the legislation, then the requirement regarding headroom will be met. The Authority has maintained this position in this Draft Decision because it has no objective or quantitative evidence that the level of headroom has been eroded or, if it has been eroded since 16 March 2007, whether that level of erosion is greater than one might consider to be relatively stable over time.

In this regard, the indicators of change in headroom proposed by Integral are a useful starting point in investigating this issue.

- (a) since 1 July 2007 discounts offered by retailers have declined, although discounts are still being offered;
- (b) the number of second-tier retailers that are actively managing customers (as opposed to merely holding a retail authority) has increased since the commencement of full retail competition; and
- (c) the data received from retailers indicates that the number of customers moving from Notified Prices to market contracts has continued to increase steadily since the commencement of full retail competition.

To consider this issue further in preparing its Final Decision, the Authority would require a clear view from retailers regarding:

- (a) what headroom they believe was available in the existing regulated tariffs as at 16 March 2007;
- (b) what headroom they believe is available in the current notified prices;
- (c) why they believe the suggested change has occurred; and
- (d) what increase they believe the Authority should add onto the BRCI in order to bring headroom back into a relatively stable band.

The views of other interested parties on any aspects of this question would also be appreciated. This is a potentially significant issue and the Authority is of the view that the basis for such a decision needs to be as transparent to all interested parties as is possible. At the same time, the Authority appreciates the commercial sensitivity of such matters and stresses that confidential submissions can be made, with the Authority subject to the confidentiality provisions of the *Queensland Competition Authority Act 1997* (sections 187 and 239 specifically refer).

Notwithstanding all of the above, there is then the question of, if all costs elements have been appropriately addressed in terms of the Electricity Act and the Electricity Regulation and it is still concluded that headroom has decreased, can the Authority further address the issue of headroom given the principle that subordinate legislation (the 26 August 2008 Delegation from the Minister) can not be inconsistent with, or over-ride, the superior legislation of the Electricity Act and the Electricity Regulation, in that order.

Non-market customers

Origin (2008a) suggested that it was the intention of the Minister's delegation that that "there should be no retailing to non-market customers at a loss".

The Authority's Position: To date, the Authority has taken the view that, if all cost increases are adequately taken into account in the determination of the BRCI, then notified prices will be maintained in cost terms at the level that existed prior to the introduction of FRC and that this was all that was necessary in terms of the relevant delegations. To do otherwise would require the Authority to review the cost reflectivity of all existing retail tariffs and, if it considered they were not cost reflective, increase notified prices accordingly. The Authority considers that this is beyond the terms of the Current Delegation.

6.5 Other Issues relevant to the Total BRCI

Customer concessions

Several retailers raised the issue of customer concession schemes and other Government programs that retailers administer on behalf of Government. APG (2008) suggested that such schemes add extra costs to retailers' operations which are not fully recovered. APG suggested that, whilst such schemes have not been taken into account in past decisions of the Authority, the current BRCI should factor in such costs.

The Authority's Position: The Authority understands that Community Service Obligations (CSO) and other community programs are generally fully cost recovered from the responsible government body with retailers receiving payment for administration. For example, the Community Ambulance Cover Scheme in Queensland provides for the Commissioner of State Revenue to pay an electricity retailer an administration fee for performing its functions as required.

The administration of customer concessions and CSO policies are matters for the Government to determine and the Authority considers that any concerns with the level of cost reimbursement for such schemes is a matter for retailers and Government to determine and that, accordingly, the Authority should not seek to address such matters in the determination of the BRCI.

Notwithstanding this, there has also been no evidence presented that there has been an increase in such costs, and it is the increase in costs that is relevant for this Draft Decision not the level of absolute costs.

7. DRAFT DECISION

The Authority estimates the BRCI to be 13.79 c/KWh in 2009-10. This represents an expected increase of 13.63% in the BRCI between 2008-09 and 2009-10.

The cost of energy is expected to rise in total by 13.9% over the year. As the NEM load of Queensland is estimated to decrease by 1.6% in 2008, the cost of energy is estimated to rise by 15.8% per kilowatt hour, accounting for 49.9% of the increase in the BRCI.

Network costs are estimated to rise by 12.3% per kilowatt hour over the year, accounting for 42.7% of the increase in the BRCI for 2008-09.

Retail costs are expected to be 10.5% higher per kilowatt hour in 2009-10. As a result, retail costs also have a small positive impact on the BRCI.

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

In the preceding chapters, the Authority has set out its estimate of the individual components of the BRCI. In chapter 2, the Authority considered six scenarios in relation to the cost of energy component and adopted (for the reasons stated in chapter 2) the scenario based on no CPRS impact and a regression-based forecast of LRMC in forming its view of the likely total cost of purchasing energy to supply the NEM load of Queensland. Table 7.1 sets out a summary of the Authority's Draft Decision on the BRCI.

Table 7.1 Components of the BRCI in 2008-09 and 2009-10, (\$m)

<i>Cost component</i>	<i>2008-09</i>	<i>2009-10</i>	<i>% change</i>
Cost of energy (\$million)	1,930	2,199	13.9
Network costs (\$million)	2,131	2,354	10.5
Retail costs (\$million)	432	470	8.7
NEM load of Queensland (GWh)	37,040	36,437	-1.6

Note: The NEM load has been calculated to the nearest kWh. Numbers may not add due to rounding.

Based on the figures contained in Table 7.1, the Authority has calculated that the BRCI will increase by 13.63% 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>2008-09 c/kWh</i>	<i>2009-10 c/kWh</i>	<i>Change (%)</i>	<i>Share of total costs 2009-10 %</i>	<i>Change in BRCI (%)</i>
Cost of energy	5.21	6.04	15.82	42.96	6.80
LRMC of energy	2.13	2.67	25.37	17.56	4.45
Purchase cost of energy	2.65	2.87	8.36	21.81	1.82
Other energy costs	0.44	0.50	14.45	3.59	0.52
Network costs	5.75	6.46	12.28	47.43	5.82
Distribution	4.53	5.08	12.20	37.32	4.55
Transmission	1.23	1.38	12.60	10.11	1.27
Retail costs	1.17	1.29	10.52	9.62	1.01
Operating costs	0.42	0.45	7.90	3.47	0.27
Acquisition/retention costs	0.14	0.15	4.88	1.14	0.06
Margin	0.61	0.69	13.63	5.0	0.68
Total	12.13	13.79	13.63	100.0	13.63

Note: Totals may not add due to rounding

The expected increase in network costs and the cost of energy account for the majority of the increase in the BRCI in 2009-10. This reflects the significant investment in network renewal by the network owners and the impact of rising fuel and capital costs on LRMC.

BRCI calculations under all six cost of energy scenarios are presented for information only in **Attachment 2**.

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ATTACHMENT 1



QUEENSLAND COMPETITION AUTHORITY

26 AUG 2008

(DATE RECEIVED)



Queensland
Government

Office of the
Minister for Mines and Energy

Mr Brian Parmenter
Chairman
Queensland Competition Authority
GPO Box 2257
BRISBANE QLD 4001

Dear Mr Parmenter

I refer to the current requirement that the Queensland Competition Authority (QCA) calculate the 2009-10 Benchmark Retail Cost Index for electricity (BRCI) and publish revised Notified Prices by 1 December 2008.

I am pleased to inform you that the Government has decided to extend the existing timeframe and will now require the Draft Decision on the 2009-10 BRCI by 1 December 2008 and the Final Decision by 1 March 2009. To this end, please find attached a new Certificate of Delegation which revokes the previous delegation.

Should you have any enquiries, please contact Ms Michelle Norris of the Department of Mines and Energy on telephone 3225 8255.

Yours sincerely

GEOFF WILSON MP
Minister for Mines and Energy

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ABN 65 556 315 158

Dated: 26th August 2008

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), from the date of this delegation, I, the Honourable Geoff Wilson MP, Minister for Mines and Energy, delegate to the Queensland Competition Authority (QCA) the following functions and powers:

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.

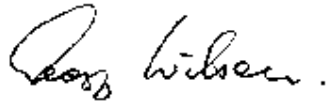
Conditions of delegation

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 AARR determined for each year of Ergon Energy's current access arrangement (covering the period 2005-03 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 1 March 2009;
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.

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

. . . Dated: 28th August 2006

This delegation revokes any previous delegation made in relation to this matter and may be revoked or amended by the Queensland Minister for Mines and Energy at any time.



GEOFF WILSON MP
Minister for Mines and Energy

ATTACHMENT 2

BRCI Calculations Under Alternate Cost of Energy Scenarios

Chapter 2 included six possible scenarios regarding the estimation of the cost of energy component of the 2009-10 BRCI.

As noted in Chapter 2, the Authority has decided that scenario 4, incorporating regression analysis costs and no CPRS effects, best represents the likely total energy costs to be met by retailers in 2009-10.

The choice of approach also impacts on retail costs as the retail margin is applied to total costs and will result in differing outcomes for the BRCI calculation.

This attachment provides the BRCI calculation that would accompany each of the alternate cost of energy scenarios.

Table A2.1 Scenario 1: Step-change LRMC forecast with no CPRS

	<i>2008-09</i> <i>c/kWh</i>	<i>2009-10</i> <i>c/kWh</i>	<i>Change</i> <i>(%)</i>	<i>Share of total</i> <i>costs 2008-09</i> <i>%</i>	<i>Change in</i> <i>BRCI</i> <i>(%)</i>
Cost of energy	5.21	6.07	16.49	42.96	7.09%
LRMC of energy	2.13	2.71	27.01	17.56	4.74%
Purchase cost of energy	2.65	2.87	8.36	21.81	1.82%
Other energy costs	0.44	0.50	14.45	3.59	0.52%
Network costs	5.75	6.46	12.28	47.43	5.82%
Distribution	4.53	5.08	12.20	37.32	4.55%
Transmission	1.23	1.38	12.60	10.11	1.27%
Retail costs	1.17	1.29	10.68	9.62	1.03%
Operating costs	0.42	0.45	7.90	3.47	0.27%
Acquisition/retention costs	0.14	0.15	4.88	1.14	0.06%
Margin	0.61	0.69	13.94	5.0	0.70%
Total	12.13	13.82	13.94	100%	13.94%

Source: QCA based on CRA and ACIL Tasman analysis. Totals may not add due to rounding.

Table A2.2 Scenario 2: Step-change LRM forecast with 10% CPRS target

	2008-09 c/kWh	2009-10 c/kWh	Change (%)	Share of total costs 2008-09 %	Change in BRCI (%)
Cost of energy	5.21	6.81	30.69	42.96	13.18%
LRMC of energy	2.13	3.45	61.74	17.56	10.84%
Purchase cost of energy	2.65	2.87	8.36	21.81	1.82%
Other energy costs	0.44	0.50	14.45	3.59	0.52%
Network costs	5.75	6.46	12.28	47.43	5.82%
Distribution	4.53	5.08	12.20	37.32	4.55%
Transmission	1.23	1.38	12.60	10.11	1.27%
Retail costs	1.17	1.33	14.02	9.62	1.35%
Operating costs	0.42	0.45	7.90	3.47	0.27%
Acquisition/retention costs	0.14	0.15	4.88	1.14	0.06%
Margin	0.61	0.73	20.36	5.0	1.02%
Total	12.13	14.60	20.36	100%	20.36%

Source: QCA based on CRA and ACIL Tasman analysis. Totals may not add due to rounding.

Table A2.3 Scenario 3: Step-change LRM forecast with 20% CPRS target

	2008-09 c/kWh	2009-10 c/kWh	Change (%)	Share of total costs 2008-09 %	Change in BRCI (%)
Cost of energy	5.21	6.96	33.61	42.96	14.44%
LRMC of energy	2.13	3.60	68.88	17.56	12.10%
Purchase cost of energy	2.65	2.87	8.36	21.81	1.82%
Other energy costs	0.44	0.50	14.45	3.59	0.52%
Network costs	5.75	6.46	12.28	47.43	5.82%
Distribution	4.53	5.08	12.20	37.32	4.55%
Transmission	1.23	1.38	12.60	10.11	1.27%
Retail costs	1.17	1.34	14.70	9.62	1.41%
Operating costs	0.42	0.45	7.90	3.47	0.27%
Acquisition/retention costs	0.14	0.15	4.88	1.14	0.06%
Margin	0.61	0.74	21.68	5.0	1.08%
Total	12.13	14.76	21.68	100%	21.68%

Source: QCA based on CRA and ACIL Tasman analysis. Totals may not add due to rounding.

Table A2.4 Scenario 4: Regression-based LRM forecast with no CPRS

	<i>2008-09</i> <i>c/kWh</i>	<i>2009-10</i> <i>c/kWh</i>	<i>Change</i> <i>(%)</i>	<i>Share of total</i> <i>costs 2008-09</i> <i>%</i>	<i>Change in</i> <i>BRCI</i> <i>(%)</i>
Cost of energy	5.21	6.04	15.82	42.96	6.80%
LRMC of energy	2.13	2.67	25.37	17.56	4.45%
Purchase cost of energy	2.65	2.87	8.36	21.81	1.82%
Other energy costs	0.44	0.50	14.45	3.59	0.52%
Network costs	5.75	6.46	12.28	47.43	5.82%
Distribution	4.53	5.08	12.20	37.32	4.55%
Transmission	1.23	1.38	12.60	10.11	1.27%
Retail costs	1.17	1.29	10.52	9.62	1.01%
Operating costs	0.42	0.45	7.90	3.47	0.27%
Acquisition/retention costs	0.14	0.15	4.88	1.14	0.06%
Margin	0.61	0.69	13.63	5.0	0.68%
Total	12.13	13.79	13.63	100%	13.63%

Source: QCA based on CRA and ACIL Tasman analysis. Totals may not add due to rounding.

Table A2.5 Scenario 5: Regression-based LRM forecast with 10% CPRS target

	<i>2008-09</i> <i>c/kWh</i>	<i>2009-10</i> <i>c/kWh</i>	<i>Change</i> <i>(%)</i>	<i>Share of total</i> <i>costs 2008-09</i> <i>%</i>	<i>Change in</i> <i>BRCI</i> <i>(%)</i>
Cost of energy	5.21	6.30	20.96	42.96	9.00%
LRMC of energy	2.13	2.94	37.94	17.56	6.66%
Purchase cost of energy	2.65	2.87	8.36	21.81	1.82%
Other energy costs	0.44	0.50	14.45	3.59	0.52%
Network costs	5.75	6.46	12.28	47.43	5.82%
Distribution	4.53	5.08	12.20	37.32	4.55%
Transmission	1.23	1.38	12.60	10.11	1.27%
Retail costs	1.17	1.30	11.73	9.62	1.13%
Operating costs	0.42	0.45	7.90	3.47	0.27%
Acquisition/retention costs	0.14	0.15	4.88	1.14	0.06%
Margin	0.61	0.70	15.96	5.0	0.80%
Total	12.13	14.07	15.96	100%	15.96%

Source: QCA based on CRA and ACIL Tasman analysis. Totals may not add due to rounding.

Table A2.6 Scenario 6: Regression-based LRMC forecast with 20% CPRS target

	<i>2008-09</i>	<i>2009-10</i>	<i>Change</i>	<i>Share of total</i>	<i>Change in</i>
	<i>c/kWh</i>	<i>c/kWh</i>	<i>(%)</i>	<i>costs 2008-09</i>	<i>BRCI</i>
				<i>%</i>	<i>(%)</i>
Cost of energy	5.21	6.45	23.72	42.96	10.19%
LRMC of energy	2.13	3.08	44.67	17.56	7.85%
Purchase cost of energy	2.65	2.87	8.36	21.81	1.82%
Other energy costs	0.44	0.50	14.45	3.59	0.52%
Network costs	5.75	6.46	12.28	47.43	5.82%
Distribution	4.53	5.08	12.20	37.32	4.55%
Transmission	1.23	1.38	12.60	10.11	1.27%
Retail costs	1.17	1.31	12.38	9.62	1.19%
Operating costs	0.42	0.45	7.90	3.47	0.27%
Acquisition/retention costs	0.14	0.15	4.88	1.14	0.06%
Margin	0.61	0.71	17.20	5.0	0.86%
Total	12.13	14.22	17.20	100%	17.20%

Source: QCA based on CRA and ACIL Tasman analysis. Totals may not add due to rounding.