QUEENSLAND COMPETITION AUTHORITY

Draft Determination

Regulated Retail Electricity Prices 2012-13

March 2012

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The Authority wishes to acknowledge the contribution of the following staff to this report

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SUBMISSIONS

Public involvement is an important element of the decision-making processes of the Queensland Competition Authority (the Authority). Submissions are invited from interested parties concerning the Authority's Draft Determination of Regulated Retail Electricity Prices for 2012-13. The Authority will take account of all submissions received by the due date.

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 stakeholders provided a printed copy 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 **13 April 2012**.

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 versions 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 electronically. 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 information, disclosure of which would be contrary to the public interest (within the meaning of the *Right to Information Act 2009 (RTI)*), 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 a RTI 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 Authority on (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

The Authority has been delegated the task of setting regulated retail electricity prices (notified prices) for Queensland by the Minister for Energy and Water Utilities (the Minister). While many consumers have opted to enter into a market contract with the retailer of their choice, a significant proportion of Queenslanders (particularly in the Ergon Energy distribution area) remain on non-market contracts paying notified prices.

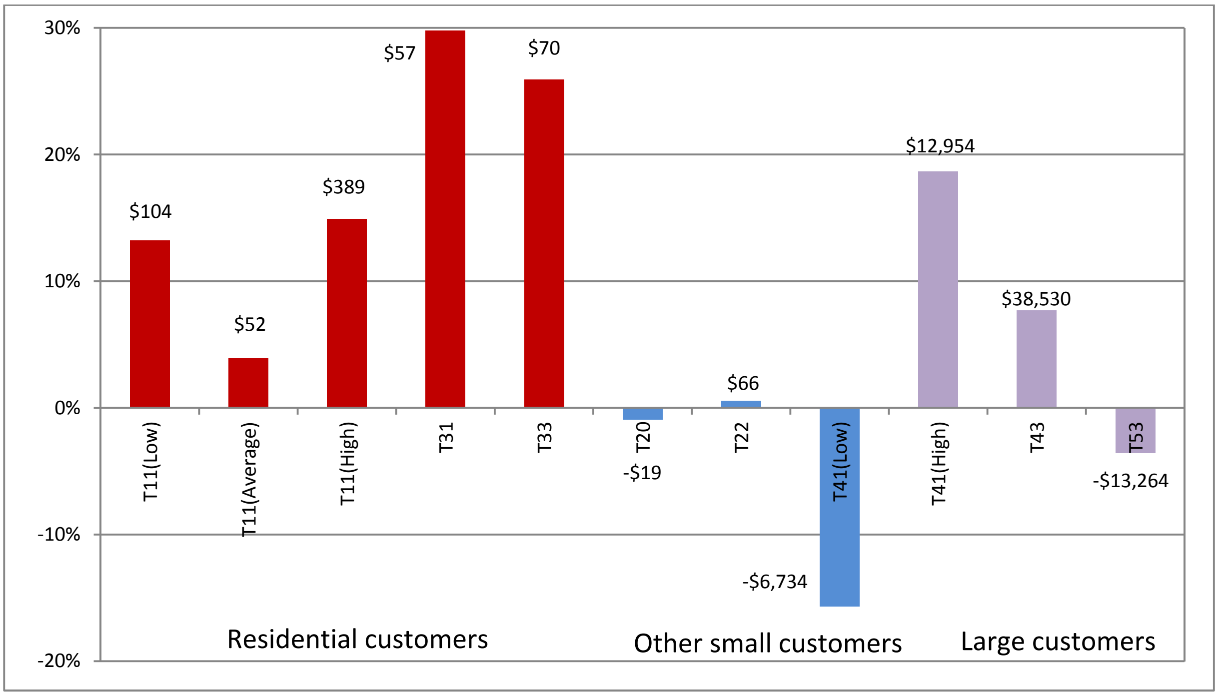
Since the start of Full Retail Competition (FRC), the Authority has adjusted the existing notified prices annually according to its calculation of the Benchmark Retail Cost Index (BRCI). This year, the Authority is required to set notified prices for 2012-13 based on an N+R cost build-up approach where the N (network cost) component is treated as a pass through and the R (energy and retail cost) component is determined by the Authority. This is a very different task to that undertaken previously and will lead to the establishment of a new set of retail tariffs aligned with the prevailing network tariff structure and retail prices which better reflect the cost of each customer's consumption. The Minister's Delegation and the Terms of Reference for this Price Determination are provided at **Appendix A.**

In determining the notified prices to apply in 2012-13, the Authority is also required to have regard to the effect of its Price Determination on competition in the Queensland retail electricity market, the Queensland Government's Uniform Tariff Policy and the need for transitional arrangements for certain customer groups.

Unlike previous years under the BRCI where prices for all tariffs were increased by the same percentage, under the new arrangements different tariffs will be impacted differently. Moreover, the Authority was required to change the main residential tariff (Tariff 11) from a flat tariff to an inclining block tariff. The impact of this change on households will vary according to their level of consumption.

The following graph shows the impact the new tariff structure and pricing arrangements will have (on average) for various customer groups.

Change in typical customer's annual electricity bill in 2012-13, by tariff



For example, the annual bill for a typical residential customer on Tariff 11 (consuming 5,370 kWh per year) is expected to increase by 3.9% (or $52). However, the impact will be higher for those customers with lower annual consumption (due to the re-balancing of prices towards higher fixed charges and lower consumption charges) and also for those with higher annual consumption (due the effect of the higher variable rate charged on the highest step of the IBT). For a typical household (consuming 5,370 kWh per year on Tariff 11 and 1,965 kWh per year on Tariff 33), the annual bill is estimated to increase by 7.6% or $122 in 2012-13. If not for the imposition of the Commonwealth's carbon tax, the annual bill for these customers would instead have decreased, by $70.

Some small customers with higher levels of consumption may be able to reduce their costs by taking up the voluntary residential time-of-use tariff (Tariff 12), instead of staying on the IBT, and shifting their electricity consumption from the costly peak period to the less costly shoulder or off-peak periods. However, this option will provide no relief for residential customers consuming at lower levels as their cost would be even higher on the time-of-use tariff.

The relatively large percentage increases for Tariffs 31 and 33 (off-peak controlled load tariffs) are due to the new prices more accurately reflecting the costs of supply. Price impacts for other small customers (consuming less than 100 MWh per year) are small or negative, whereas for large customers the impacts are mixed.

It is important to note that the changes shown are for levels and patterns of consumption that are typical of customers currently on each of the regulated retail tariffs shown. It is likely that some customers may have levels and patterns of consumption that differ quite significantly from those assumed in this analysis and may therefore experience quite different impacts.

The notified prices for 2012-13 reflect a number of general factors including:

(a) further increases in network charges, with Energex and Ergon Energy expected to recover additional revenue from network charges of around 15.7% and 11.3% respectively;

(b) an increase in the underlying cost of energy for small customers of around 41%, primarily due to the carbon tax;

(c) retail operating costs for small customers remaining largely unchanged; and

(d) the one-off effects of moving from an ad hoc set of tariffs that had evolved over time to a new tariff structure reflecting the true costs of supply.

The Commonwealth's carbon tax will push the typical residential household's annual bill around $192.35 (11.2%) higher than it might have been otherwise. In addition, the Commonwealth Enhanced Renewable Energy Target Scheme, which has not been removed despite the introduction of the carbon tax, adds $92.80 (5.4%) to a typical residential household's annual bill.

As a short term transitional measure, the Authority has also retained a number of the existing tariffs that would otherwise have been unavailable from 1 July 2012. This is to allow certain customer groups time to adjust their consumption to better suit the new tariffs.

The extent of change occurring in this year is unlikely to be repeated in future years. This year, new tariff structures based on network tariffs and prices that reflect the true costs of supply are replacing an ad hoc set of tariffs that had evolved over time.

In comparison to the results from this complete review of tariff structures and prices, had the Authority persisted with the BRCI approach, prices for all regulated retail tariffs would have increased by more than 20% in 2012-13.

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GLOSSARY

2009 Review	The Authority's *Review of Electricity Pricing and Tariff Structures* – Stages 1 and 2
ACB	Australian Carbon Benchmark
ACIL	ACIL Tasman
ACIL Draft Methodology Report	ACIL Tasman, *Draft Methodology for Estimating Energy Purchase Costs, Prepared for the Queensland Competition Authority*, October 2011, available from: www.qca.org.au
ACIL Draft Report	ACIL Tasman, *Draft Report for Estimating* Energy *Purchase Costs for 2012-13 Retail Tariffs, Prepared for the Queensland Competition Authority*, March 2012, available from: www.qca.org.au
ACT	Australian Capital Territory
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AFMA	Australian Financial Markets Association
APG	Australian Power and Gas
APR	Annual Planning Report published by Powerlink
Authority	Queensland Competition Authority
BRCI	Benchmark Retail Cost Index
BRIG	Bundaberg Regional Irrigators Group
CAC	Connection Asset Customer
CARC	Customer Acquisition and Retention Costs
CCIQ	Chamber of Commerce and Industry Queensland
CPI	Consumer Price Index
CPRS	Carbon Pollution Reduction Scheme
CSO	Community Service Obligation
Delegation	The Delegation from the Minister for Energy and Water Utilities, pursuant to section 90AA(1) of the *Electricity Act 1994*, directing the Authority to determine regulated retail electricity tariffs (notified prices) to apply from 1 July 2012 to 30 June 2013.
Direction	The Direction from the Minister for Finance and the Arts and Acting Treasurer and Minister for State Development and Trade, pursuant to section 10(e) of the *Queensland Competition Authority Act 1997*, directing the Authority to investigate, and report on, a possible alternative retail electricity pricing methodology and schedule of retail electricity tariffs for the period commencing 1 July 2012 to 30 June 2013.
Draft Methodology Paper	The Draft Methodology Paper issued by the Authority on 11 November 2011 (acting under the Delegation)
DUOS	Distribution Use of System

EBITDA	Earnings before interest, tax, depreciation and amortisation
EEQ	Ergon Energy Queensland
Electricity Act	*Electricity Act 1994*
ERA	Economic Regulation Authority in Western Australia
ERET	Enhanced Renewable Energy Target Scheme
ESCOSA	Essential Services Commission of South Australia
ESOO	Electricity Statement of Opportunities published by AEMO
FRC	Full Retail Competition
GEC	Gas Electricity Certificate
GST	Goods and services tax
GST Act	*Goods and Services Tax Act 1999 (Cth)*
GWh	Gigawatt hours
HV	High voltage
IBT	Inclining block tariff
ICC	Individually Calculated Customer
ICRC	Independent Competition and Regulatory Commission
IPART	Independent Pricing and Regulatory Tribunal
Issues Paper	The Issues Paper released by the Authority on 24 June 2011 (acting under the Direction)
Large customer	A customer that consumes more than 100 MWh of electricity per year
LECG	now Sapere Research Group
LGC	Large-scale Generation Certificate
LRET	Large-scale Renewable Energy Target
LRMC	Long Run Marginal Cost
Minister	Minister for Energy and Water Utilities
MW	Megawatt
MWh	Megawatt hours
NECF	National Energy Customer Framework
NEM	National Electricity Market
NER	National Electricity Rules
Notified/regulated retail prices	The electricity prices that a retailer may charge its non-market customers, as defined under section 90 of the *Electricity Act 1994*
NSLP	Net System Load Profile
ORER	Office of the Renewable Energy Regulator
OTTER	Office of the Tasmanian Economic Regulator
POE	Probability of exceedance

Price Determination	The Authority's determination of notified prices to apply from 1 July 2012 to 30 June 2013 (acting under the Delegation)
QCA Act	*Queensland Competition Authority Act 1997*
QCOSS	Queensland Council of Social Service
Regulation	Electricity Regulation 2006
Relevant tariff year	The period 1 July 2012 to 30 June 2013, as defined under section 329(3) of the *Electricity Act 1994*
REES	Residential Energy Efficiency Scheme in South Australia
RBA	Reserve Bank of Australia
ROC	Retail operating costs
ROLR	Retailer of Last Resort
RPP	Renewable Power Percentage
SAC	Standard Asset Customer
SEQ	South East Queensland
SFE	Sydney Futures Exchange
SFG	SFG Consulting
Small customer	A customer that consumes less than 100 MWh of electricity per year
SRES	Small-scale Renewable Energy Scheme
STC	Small-scale Technology Certificate
STP	Small-scale Technology Percentage
TFS	Tradition Financial Services
TOU	Time-of-use
TUOS	Transmission Use of System
UTP	The Queensland Government's Uniform Tariff Policy
WACC	Weighted Average Cost of Capital
WAPC	Weighted Average Price Cap
WPI	Wage Price Index

1. INTRODUCTION

1.1 Background

Prior to 1998, all electricity customers in Queensland were on regulated retail electricity prices (notified prices) determined by the Queensland Government. For some large electricity customers, the option to choose their electricity retailer commenced in 1998. However, for the majority of customers, including all residential customers, the option to choose only came into effect with the introduction of Full Retail Competition (FRC) on 1 July 2007.

Since the introduction of FRC, electricity retailers have been able to offer to supply electricity to all customers, including those on notified prices. Customers who take up a market offer transfer from the notified price to the market contract price they have agreed with the retailer of their choice. Small customers who accept a market contract may revert to a non-market contract with their current retailer at the notified price on the expiry of their market contract, or as otherwise provided for in their market contract.

The Minister for Energy and Water Utilities (the Minister) has delegated the function of determining notified prices to the Authority since the start of FRC. To date, the Authority has adjusted notified prices annually in accordance with the Benchmark Retail Cost Index (BRCI) process that was prescribed in the *Electricity Act 1994* (the Electricity Act) and Electricity Regulation 2006 (the Regulation).

The current notified tariff schedule includes 20 regulated retail tariffs for which notified prices have been set. While some of the current tariffs were introduced more recently, most were introduced over 20 years ago. The current range of tariffs available to customers consists of residential, business and agricultural/farming tariffs.

As at 31 December 2011, there were 17[1] retailers supplying customers in the Queensland retail market (12 of these supplying small customers). However, competition in Queensland is largely limited to South East Queensland (SEQ) (Energex's distribution area) as a result of the Government's Uniform Tariff Policy (UTP)[2].

As at 31 December 2011, approximately 1.15 million (or 56.6%) of small customers and 7,129 (or 32.8%) of large customers in Queensland remained on notified prices, the majority of these in Ergon Energy's distribution area. Notified prices therefore remain an important feature of the Queensland retail electricity market.

The 2009 Review

On 25 June 2009, the Authority received a Ministerial Direction (the 2009 Direction) under section 10(e) of the *Queensland Competition Authority Act 1997* (the QCA Act) directing it to:

(a) examine the BRCI methodology and alternative price-setting methodologies for reflecting the costs of supplying electricity; and

[1] Some retailers hold more than one licence.

[2] The UTP works by subsidising customers in Ergon Energy's distribution area where network costs are considerably higher than in the more densely populated SEQ. Under the UTP, the Queensland Government subsidises the notified prices payable by regional customers supplied by Ergon Energy Queensland (EEQ) via a Community Service Obligation (CSO) payment. EEQ is the only retailer subsidised under the UTP. In general, subsidised notified prices, particularly for small customers, are below the prices available from other retailers offering market contracts.

(b) examine Queensland's existing retail electricity tariffs and alternative tariff structures which may assist in the long-term management of peak electricity demand and to encourage efficiency.

The *Review of Electricity Pricing and Tariff Structures* (the 2009 review) was completed in two stages[3].

In its Final Report on Stage 1 of the 2009 Review, the Authority concluded that the BRCI methodology had a number of flaws, and that the existing suite of notified prices was unlikely to fully reflect the costs of supply (at least not for each individual tariff group) and did not provide good signals to customers regarding the underlying costs of their electricity usage.

To achieve significant improvements over the existing BRCI methodology, the Authority recommended an alternative retail pricing approach based on a N (network) + R (energy and retail) approach, with the R component including appropriate allowances for energy and retail costs and the N component being a direct pass through of network costs to customers.

Following Stage 2 of the 2009 Review, the Authority recommended that retail tariffs be made as cost-reflective as possible, network and retail tariffs be aligned and a voluntary time-of-use tariff be introduced for residential customers who already had interval meters in place. The Authority also suggested including a seasonal component in some tariffs (though this suggestion was not subsequently accepted).

The 2011 Direction

On 11 May 2011, and in response to the Authority's recommendations, the Authority received a second Ministerial Direction (the 2011 Direction) under section 10(e) of the QCA Act requiring it to investigate, and report on:

(a) an alternative retail electricity pricing methodology for the determination of cost components under an N (network) + R (energy and retail) approach; and

(b) an alternative set of retail electricity tariffs, based on an N+R approach, which could be applied from 1 July 2012.

The 2011 Direction was a transitional measure to allow the 2012-13 pricing review process to commence while the necessary amendments were made to the Electricity Act and the Regulation to remove the BRCI approach to adjusting notified prices and to allow for the introduction of a new, cost-reflective price setting methodology.

Acting under the 2011 Direction, the Authority released an Issues Paper on 24 June 2011 and received 20 submissions in response.

1.2 Current Delegation and Terms of Reference

The Electricity Act and the Regulation were amended on 13 September 2011. The amended Electricity Act allows the Minister to delegate the function of determining notified prices to the Authority. Section 329 of the Electricity Act provides that any investigations or consultations previously undertaken by the Authority under section 10(e) of the QCA Act will be deemed sufficient for the purposes of the 2012-13 price determination process.

[3] *Review of Electricity Pricing and Tariff Structures – Stage 1, Final Report*, September 2009 and *Review of Electricity Pricing and Tariff Structures – Stage 2, Final Report*, November 2009, available from www.qca.org.au.

On 22 September 2011, the Authority received a Delegation from the Minister under section 90AA(1) of the Electricity Act requiring it to determine notified prices to apply from 1 July 2012 to 30 June 2013 (the price determination). The Delegation also includes a Terms of Reference for the price determination.

Under section 90(5) of the Electricity Act, in making a price determination, the Authority is required to have regard to:

(a) the actual costs of making, producing or supplying the goods or services;

(b) the effect of the price determination on competition in the Queensland retail electricity market;

(c) any matter the Authority is required by delegation to consider; and

(d) any other matter the Authority considers relevant.

Under the Delegation, and in accordance with (c) above, the Authority is also required to have regard to:

(a) the Queensland Government's UTP, which ensures customers of the same class have access to uniform retail tariffs and pay the same notified price for their electricity supply, regardless of their geographic location; and

(b) a range of specific matters contained in an attachment to the Delegation.

The Delegation is broadly consistent with the 2011 Direction, with the exception of some minor amendments which provide more clarity regarding the Authority's task. In particular, the Delegation specifies that the Authority should, to the extent possible, base its determination on an N + R cost build-up approach to setting notified prices, where:

(a) the N (or network cost) component is treated as a pass through – in determining the N component, the Authority must consider the network charges to be levied by Energex for each tariff for the relevant tariff year; and

(b) the R (or energy and retail cost) component is determined by the Authority.

Calculating the R component

Energy Costs

The energy cost component of each regulated retail tariff should include the cost of purchasing energy, environmental and renewable energy costs, energy losses and National Electricity Market (NEM) fees.

In calculating the energy cost component, the Authority must consider:

(a) the cost of energy;

(b) fees, including charges for market and ancillary services, imposed by the Australian Energy Market Operator (AEMO) under the National Electricity Rules (NER);

(c) energy losses as published by AEMO;

(d) the likely impact resulting from Commonwealth legislation to put a price on carbon dioxide emissions;

(e) the efficient costs of meeting any obligations under environmental and energy efficiency schemes (including present and future State and Commonwealth schemes); and

(f) a mechanism to address any new compulsory scheme that imposes material costs on the retailer.

Retail Costs

In determining the retail cost component of each regulated retail tariff, the Authority must:

(a) consider the retail costs that would reasonably be incurred by an efficient, representative retailer, the characteristics of which should be determined by the Authority; and

(b) determine an appropriate retail margin giving consideration to any risks not compensated for elsewhere.

Other Issues

In making its price determination, the Authority must have regard to the following matters contained in the Attachment to the Delegation:

(a) the general supply residential tariff (Tariff 11) is to be structured as an inclining block tariff (IBT);

(b) a new voluntary time-of-use tariff is to be established for residential customers and any customer who opts to transfer to this tariff, provided they have the appropriate metering, will be permitted to revert to the standard regulated tariff for residential customers in accordance with the requirements set out in the regulated retail tariff schedule;

(c) for farming and irrigation tariffs, targeted consultation should be undertaken with relevant stakeholders and industry groups, and consideration given to whether any transitional arrangements are needed for customers who may be required to move from one tariff to another;

(d) an appropriate tariff is to be established for customers who are supplied under the Rural Subsidy Scheme, or are located in a drought declared area;

(e) an appropriate tariff for street lighting customers in Ergon Energy’s network area is to be established, and consideration given to whether any transitional arrangements are needed for customers on the existing tariff (Tariff 71);

(f) consideration should be given to transitional arrangements for customers who are on obsolete and declining block tariffs;

(g) from 1 July 2012, all existing and new non-residential customers in Energex’s network area who consume more than 100 megawatt hours (MWh) per annum will be unable to access regulated retail electricity tariffs, and must be on a market contract; and

(h) as at 1 July 2012, any customer who is on an obsolete or declining block tariff will be required to move to, or be transitioned to, an alternative regulated retail tariff.

The Authority is required to publish a report on its Draft Price Determination (Draft Determination) on 30 March 2012 and publish a report of its Final Price Determination (Final Determination) and gazette the bundled retail tariffs no later than 31 May 2012.

The Minister’s covering letter and Delegation are provided in **Appendix A.**

1.3 The Review Process to Date

On 24 June 2011, the Authority released an Issues Paper advising interested parties of the commencement of the review.

The Authority received 20 submissions in response to the Issues Paper. The list of submissions received is provided in **Appendix B**. A copy of the Issues Paper and the submissions received can be accessed from the Authority's website.

The Authority engaged ACIL Tasman (ACIL) to provide expert advice on estimating energy costs to be included in the R component of regulated retail tariffs for 2012-13. ACIL's Draft Methodology Report[4] can be accessed from the Authority's website.

On 11 November 2011, the Authority released a Draft Methodology Paper, which set out the Authority's preliminary views and proposed approaches to determining the key elements of regulated retail tariffs and prices, with a particular focus on estimating energy and retail costs (the R component). The Authority hosted a workshop on 25 November 2011 to discuss the matters raised in the Draft Methodology Paper. The workshop was attended by 36 stakeholders.

The Authority received 28 submissions in response to the Draft Methodology Paper. The list of submissions received is provided in **Appendix B**. A copy of the Draft Methodology Paper and the submissions received can be accessed from the Authority's website.

The Authority is now releasing this Draft Determination, which includes draft regulated retail tariffs and prices for 2012-13 and explains how these were determined. In making its Draft Determination, the Authority has taken into account the requirements of the Electricity Act and the Delegation, matters raised in submissions, ACIL's report on the cost of energy and its own investigations.

Submissions are now invited in response to the Draft Determination and should be received by the Authority no later than 13 April 2012. In preparing its Final Determination, the Authority will consider all submissions received by the due date.

A timetable for the remainder of the review is provided below.

Table 1.1: Timetable for the Review

Task	*Dates*
Release of Authority's Draft Determination and ACIL's Draft Report	30 March 2012
Submissions on Draft Determination due	**13 April 2012**
Release of Authority's Final Determination and ACIL's Final Report	**31 May 2012**

[4] ACIL Tasman, *Draft Methodology for Estimating Energy Purchase Costs, Prepared for the Queensland Competition Authority*, November 2011, available from: www.qca.org.au.

2. NETWORK COSTS

Retail electricity prices comprise three main cost components. The first of these are the costs associated with transporting electricity through the transmission and distribution networks. Typically, network costs account for around 50% of the final cost of electricity for small customers.

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

The main transmission network service provider in Queensland is Powerlink. The two main distribution networks in Queensland are owned and operated by Energex and Ergon Energy. Energex’s network services South East Queensland (SEQ), while Ergon Energy’s network extends across the remainder of the State.

As regulated monopoly businesses, the revenues to be raised via charges by Powerlink, Energex and Ergon Energy are determined by the Australian Energy Regulator (AER).

In addition to recovering their own distribution network costs, Energex and Ergon Energy also pass on to customers the cost of using Powerlink’s transmission network (transmission use of system (TUOS) charges) as well as a number of other minor transmission-related costs, including avoided TUOS payments to embedded generators and other unregulated charges paid to Powerlink or distributors for transmission-like network services.

2.1 Treatment of Network Costs

In determining each cost component of the retail electricity tariffs, the Authority must have regard to the general provisions of the Delegation, including:

(a) the actual costs of supplying electricity;

(b) the effect of its determination on competition;

(c) the Queensland Government’s UTP; and

(d) the particular matters raised in the attachment to the Delegation.

In establishing the tariff structure for 2012-13, the Delegation makes clear that, to the extent possible, the Authority’s Determination should be based on an N+R cost build-up approach to setting notified prices, where N is treated as a pass through and R is determined by the Authority.

This is a different task to that undertaken by the Authority in previous years under the requirements of the BRCI approach to setting regulated retail prices and requires that (where possible) the retail tariff structure be based on the network tariff structure in order to enable network costs to be treated as a pass through to retailers.

In determining the network cost component of each regulated retail tariff, the Authority is also required to consider the network charges to be levied by Energex for each tariff for the relevant tariff year (2012-13). This suggests that the Energex network tariff structure and charges (rather than the Ergon Energy tariff structure and charges) should form the basis of the regulated retail tariffs. In combination with the Government’s UTP, this would mean that it would be the Energex tariffs and charges that form the basis of regulated retail tariffs across the State.

The Authority is also required to have regard to the specific matters raised in the Attachment to the Delegation. In respect of network costs, and in particular the role to be played by network tariffs as the basis for regulated retail tariffs, there are several matters to be considered, including:

(a) the general residential supply tariff is to be structured as an IBT;

(b) a new voluntary time-of-use tariff is to be established for residential customers;

(c) whether any transitional arrangements are needed for customers on farming and irrigation tariffs who may be required to move from one tariff to another;

(d) an appropriate tariff is to be established for customers supplied under the Rural Subsidy Scheme or in drought affected areas;

(e) an appropriate tariff is to be established for street lighting in Ergon Energy's network area;

(f) from 1 July 2012, non-residential customers in Energex's network area who consume more than 100 MWh per annum will be unable to access regulated retail electricity tariffs and must move to a market contract; and

(g) from 1 July 2012, any customer who is on an obsolete or declining block tariff will be required to move to, or be transitioned to, an alternative regulated retail tariff.

If the Authority is to meet these requirements, the network tariffs that will form the basis of the regulated retail tariffs must be capable of accommodating them.

2.1.1 Energex's Network Tariff Structure

In its Issues Paper, the Authority noted that Energex's 2011-12 tariffs did not provide a suitable basis for some of the retail tariffs the Authority is required to consider, including inclining block and voluntary time-of-use tariffs for residential customers, tariffs for farmers and irrigators, or tariffs for customers supplied under the Rural Subsidy Scheme or in drought declared areas.

The Authority also noted that there may be particular groups of customers in the Ergon Energy network area which are not represented in the Energex area, or are not sufficiently numerous in the Energex area to warrant a separate network tariff class.

Further, the Authority queried what network tariffs should be used for very large Ergon Energy customers (those consuming more than 4 gigawatt hours (GWh) per year) who would usually have network prices which are individually tailored to a greater or lesser extent depending on the characteristics of their consumption.

However, following the release of Energex's proposed network tariffs for 2012-13 (see **Appendix C**), most of these concerns were removed. In response to the Authority's Draft Methodology Paper, there was general agreement that the 2012-13 network tariffs proposed by Energex would provide a suitable basis for most regulated retail tariffs.

Residential Inclining Block and Time-of-Use Tariffs

Energex' proposed 2012-13 network tariffs now include an inclining block network tariff and a voluntary time-of-use network tariff, for residential customers.

Tariffs for Farmers, Irrigators and Customers Supplied under the Rural Subsidy Scheme or in Drought Declared Areas

The alignment by Energex of its proposed network tariffs with existing regulated retail tariffs provides the basis for regulated retail tariffs for farmers, irrigators and customers supplied under the Rural Subsidy Scheme or in drought declared areas. In particular:

(a) regulated retail tariff 66 (flat/demand – irrigation) aligns with Energex's proposed network tariff 8300 (demand – small);

(b) regulated retail tariffs 67 (flat – farm under Rural Subsidy Scheme) and 68 (flat – irrigation in drought declared area) align with Energex's proposed network tariff 8500 (flat – small/medium business); and

(c) regulated retail tariff 65 (time-of-use – irrigation) aligns with Energex's proposed network tariff 8800 (time of use – small/medium business).

However, several submissions from organisations based in the Ergon Energy network area raised concerns about having to move to regulated retail tariffs based on Energex network tariffs and charges. For example, the Queensland Farmers Federation, CANEGROWERS and Growcom highlighted that farmers had made investment decisions based on the current tariffs and that moving to new tariffs with different structures could require considerable capital investment to adapt business processes. Farming groups also noted that water boards such as SunWater would be similarly affected and that this could affect water prices paid by farmers.

Street Lighting and Other Unmetered Supplies

The current regulated retail tariff for street lighting (Tariff 71) aligns with Energex's proposed network tariff 9600 (flat – unmetered).

In responding to the Authority's Draft Methodology Paper, Ergon Energy and Origin Energy both supported using Energex's proposed network tariff for unmetered supplies as the basis for regulated retail tariffs for unmetered supplies.

However, while Ergon Energy also supported the use of Energex's network tariff 9600 as the basis for the regulated retail tariff for these other services, it noted that some additional charges will also apply to some unmetered supply services. In order to avoid customer confusion about the application of these additional charges, Ergon Energy suggested that separate retail tariffs should be created for each different type of unmetered supply, even though they would be identical and based on the same Energex network tariff.

The other existing regulated retail tariffs for unmetered consumption are regulated retail tariffs 81 (traffic signals) and 91 (watchman service lighting). Both of these (along with Tariff 71 for street lights) align with Energex's proposed network tariff 9600 (flat – unmetered).

Obsolete and Declining Block Retail Tariffs

The Delegation requires that, from 1 July 2012, any customer currently on an obsolete or declining block tariff will be required to move to, or be transitioned to, an alternative regulated retail tariff. This suggests that all obsolete and declining block tariffs need to be removed from the regulated tariff schedule.

The existing tariffs affected by this decision are set out in Table 2.1, along with the Energex proposed network tariff that most closely matches the redundant retail tariff.

Table 2.1: Obsolete and Declining Block Tariffs to be Replaced and Alternate Network Tariff

Redundant retail tariffs	*Proposed network tariff*
Tariff 21	8500 – flat small/medium business
Tariffs 37, 62, 63, 64	8800 – time-of-use small/medium business

Customers currently on obsolete or declining block regulated retail tariffs will be moved to retail tariffs based on the network tariffs set out in Table 2.1. However, they may prefer to move to an alternate tariff of their choice if there is one that better matches their usage and consumption.

Submissions from some organisations based in the Ergon Energy network area raised concerns about having to move to new regulated retail tariffs. For example, foundry operators Bundaberg Walkers and CQMS Razer indicated that having to move from the obsolete regulated retail tariff 37, which does not have a demand charge, to a new (Energex based) regulated tariff with a demand charge that would apply to their high demand requirements could threaten their businesses.

Tariff for Card Meters

Ergon Energy has numerous customers currently supplied via a (prepaid) card-meter. While Energex's proposed flat small/medium network tariff would be suitable for Ergon Energy's card-metered business customers, there is no single tariff that can be applied to prepaid cards for small residential customers as the basic tariff for these customers will be an IBT that has differing rates according to the level of consumption. As a result, it will be necessary to create an additional regulated retail tariff, which would be available only to small customers with card-operated meters, based on one, or an average, of the charges in Energex's small customer IBT.

In response to the Authority's Draft Methodology Paper, Ergon Energy and the Queensland Government supported this proposal.

Tariffs for Large (Ergon Energy) Customers

A key network issue to be resolved relates to the appropriate basis for setting tariffs for large customers in light of the Government's policy decision to not allow non-residential customers consuming more that 100 MWh per annum in Energex's network area access to the regulated retail tariffs. As a result, it is not entirely clear whether the Energex or Ergon Energy network tariffs and charges form the most appropriate basis for determining tariffs for this group of customers.

The 2012-13 network tariffs proposed by Energex at the time the Authority released its Draft Methodology Paper included suitable tariffs to form the basis for regulated retail tariffs for the majority of large customers consuming up to 4 GWh per year. However, they did not include any tariffs intended for customers consuming more than 4 GWh per year. Beyond this level of consumption, Energex calculates individually tailored network prices which are not publicly available.

In its Draft Methodology Paper, the Authority suggested that, to fill this gap, it could require Energex to calculate one or two network tariffs that reflect the average of its cost-reflective network tariffs for all of its very large customers. These could then provide the basis for calculating regulated retail tariffs for these customers.

In responding to the Draft Methodology Paper, Energex and Ergon Energy disagreed with this proposed approach.

Energex was concerned that, due to the wide range of customer characteristics within its very large customer class (those consuming more than 4 GWh per year), calculating an average network charge based on the charges for these customers could result in notified prices for some customers that are lower than the market prices available to some of its existing customers. Energex also suggested that, as its network charges are subject to AER approval, this prevented Energex from creating tariffs for customers outside its distribution area. As an alternative, Energex suggested using its existing high voltage (HV) demand network tariff.

Ergon Energy suggested that the Authority had interpreted the Delegation too narrowly and that basing regulated retail tariffs for large customers on Ergon Energy's network charges would more closely match the network price signals applicable to large customers in the Ergon Energy distribution area. On this basis, Ergon Energy suggested that regulated retail tariffs for customers consuming between 100 MWh per year and 4 GWh per year should be based on Ergon Energy's publicly available network tariffs rather than Energex's, and that regulated retail tariffs for customers consuming more than 4 GWh per year should be based on an average of the network charges for Ergon Energy's very large customers rather than Energex's.

Implementation Issues

While it appears that it will be possible to match all existing regulated retail tariffs (apart from card meters) to a similar tariff within Energex's proposed 2012-13 network tariff structure, there will not always be a perfect alignment for all customers.

The Authority has considered the impacts of some of these changes and has introduced some transitional measures to smooth the move from old tariffs to new tariffs for some customers (see Chapter 6).

2.1.2 The Authority's Position

Other than for the treatment of large customers, there were no suggestions in submissions that the network tariffs Energex proposed for 2012-13 could not provide the basis for regulated retail tariffs.

Residential Inclining Block and Time-of-Use Tariffs

These are accommodated in Energex's proposed 2012-13 network tariff structure.

Tariffs for Farmers, Irrigators and Customers Supplied under the Rural Subsidy Scheme or in Drought Declared Areas

The Authority acknowledges the concerns raised about the potential costs to some customers of having to move to new regulated retail tariffs which may have some different features to those they are currently on. Unfortunately, there will not always be a perfect alignment between existing and new tariffs for all customers, particularly where there are currently multiple tariff choices being replaced by single new tariffs. However, one purpose of the current review is to rationalise the regulated tariff schedule and this will inevitably involve disruption for some customers. The issue here, for farmers and irrigators, may be more one relating to the timing of the required change than the extent of any change per se. In Chapter 6, the Authority has considered the impact of proposed changes on various customer groups and the need for any transitional arrangements to smooth the rate of change and consequent adjustment requirements for affected customers.

In relation to establishing appropriate tariffs for customers supplied under the Rural Subsidy Scheme or located in a drought declared area, the current tariff schedule includes separate tariffs (67 and 68) for these purposes. However, there is no clear economic basis for determining what the appropriate level of subsidy should be for those customers in these particular circumstances.

Rather than create two additional subsidised tariffs exclusively for these customers, the Authority considers it would be more appropriate for any special arrangements for these customers to be decided by Government and included in the terms and conditions that are associated with the notified prices. These arrangements have been included in a draft tariff schedule to be published with notified prices for 2012-13 (see **Appendix D**). For those customers supplied under the Rural Subsidy Scheme or in drought declared areas of the State, Tariff 20 (based on Energex's network tariff 8500 (flat – business) would be the relevant tariff but subject to the special terms and conditions set out in the tariff schedule.

Street Lighting and Other Unmetered Supplies

The Authority is not inclined to take up Ergon Energy's suggestion to create several differently named, but otherwise identical, regulated retail tariffs for each type of unmetered supply. However, for the same reasons the Authority has decided to base retail tariffs for large customers on Ergon Energy's network charges, as discussed below, the Authority has decided to base the street lighting tariff on Ergon Energy network charges, while other unmetered supplies will be based on Energex's proposed network tariff 9600 (flat – unmetered).

Obsolete and Declining Block Retail Tariffs

In accordance with the Delegation, customers currently on obsolete or declining block regulated retail tariffs should be moved to alternative regulated retail tariffs.

Many of the concerns raised in submissions regarding the use of Energex network tariffs as the basis for constructing regulated retail tariffs and hence the potential price impacts for some customers in moving to Energex based charges, are not actually about whether it is Energex or Ergon Energy network tariffs that are used but rather the fact that customers on obsolete and declining block tariffs are currently enjoying heavily subsidised electricity prices (such as those on obsolete tariff 37) and will in future be required to move to new regulated tariffs which more accurately reflect their costs of supply.

While these tariffs are clearly slated to be removed, the Authority has considered the impact of this requirement on affected customers (as it is required to do) and has introduced some transitional measures to smooth the move to new tariffs for some of these customers (see Chapter 6).

Card Meters

Given the support for its proposal to create a regulated retail tariff available only to small customers on card-operated meters, the Authority has pursued this option. In order to determine an appropriate price for this new tariff, the Authority acquired consumption data for customers with card-operated meters from Ergon Energy. This data indicates average annual consumption of approximately 7,600 kilowatt hour (kWh) per customer. Under the proposed IBT, this level of consumption would result in 5,000 kWh charged at the rate for the first block of the IBT and 2,600 kWh charged at the rate for the second block.

To arrive at an appropriate charge, given this average level of consumption, the Authority has calculated an average of the first and second inclining block rates, weighted these by the levels of consumption, to arrive at a single c/kWh rate that will be applied to customers on card operated meters. As is currently the case, customers on card-operated meters will also pay any additional fixed charges that apply to the IBT. In addition, customers on card meters will continue to be able to access controlled load tariffs 31 and 33 at the same cost as for all other residential customers.

Large (Ergon Energy) Customers

The Authority agrees with Ergon Energy that basing regulated retail tariffs for large customers on Ergon Energy's network charges would more closely match the network price signals applicable to large customers in the Ergon Energy distribution area. But this could be said of all the regulated retail tariffs which are to be based on Energex's network charges. The issue here is that the Government has a UTP which means that, in setting prices based on an N+R framework, they can either reflect the costs in the Energex area or the costs in the Ergon Energy area (or some amalgam of both) but they cannot reflect both distributors' actual charges without setting two sets of prices, one in the Energex area and a different set in the Ergon Energy area (which would not be consistent with the UTP). The Delegation indicates that it should be Energex's network charges that prevail. Given the lack of competition in the Ergon Energy network area, this seems a sensible outcome.

However, the Government's decision to not allow large customers in the Energex network area to access notified prices does give cause for thought on whether, while ever this policy stance is maintained, it would be more appropriate to set large customer tariffs (for the State) based on Ergon Energy's network charges.

In these circumstances, there are arguments to support basing regulated retail tariffs for large customers on either the Energex or Ergon Energy network tariffs and charges.

However, for the purposes of this Draft Determination and particularly in light of the Government decision regarding access to notified prices by large customers in the Energex area, the Authority has chosen to base prices for large customers (those non-residential customers consuming more than 100 MWh per annum) on Ergon Energy network charges. This approach will put electricity prices for large Ergon Energy customers on a more economic (cost-reflective) footing but is likely to also result in some significant price increases for Ergon Energy's large customers on regulated tariffs.

For comparison, the Authority has also included alternate large customer network prices based on the Energex tariffs – see **Appendix E**. Should the Government change its decision to deny large customers in the Energex network area access to regulated prices then the basis for setting large customer regulated prices would need to be reviewed.

In theory, using the Energex charges would result in lower retail prices and using the Ergon Energy charges would result in higher retail prices. On the one hand, the cost of the CSO for the Government would increase and prices to large customers would decline, while on the other, the cost of the CSO to Government would decline while prices to large customers would increase.

Large Customers Consuming 100 MWh up to 4 GWh per year

Ergon Energy has three pricing zones – East, West and Mt Isa. The East pricing zone includes almost 90% of Ergon Energy's large customers. The Authority has therefore used the network charges for Ergon Energy's East pricing zone as the basis for regulated retail tariffs for large customers.

Within the East pricing zone, there are a further three regions across which TUOS charges differ. Ergon Energy provided data that indicates the average TUOS charges for the three TUOS regions combined are similar to the charges in Transmission Region 1. Ergon Energy therefore proposed to use the TUOS charges that apply in Ergon Energy's East zone Transmission Region 1 to establish the network charges for notified prices for large customers. The Authority has adopted this approach for the purposes of this Draft Determination.

For customers consuming between 100 MWh and 4 GWh per year, Ergon Energy has four network tariffs – Standard Asset Customer (SAC) Small, SAC Medium, SAC Large and High Voltage (HV) Demand. These network tariffs provide the basis for retail tariffs 42, 43, 44 and 53 respectively. This structure is similar to that of Energex, which has three network tariffs covering this group of customers.

Very Large Customers Consuming More Than 4 GWh per year

For those customers consuming more than 4 GWh per year, Ergon Energy suggested that the Authority base notified prices on the average of the network prices for Connection Asset Customers (CACs) for those customers consuming 4 GWh to 40 GWh per year and the average of the network charges for Individually Calculated Customers (ICCs) for those customers consuming more than 40 GWh per year.

As for large customers, the Authority will use the average of all CAC customer charges from Ergon Energy's East pricing zone to provide the basis for a retail tariff for customers consuming between 4 GWh and 40 GWh per year. This will provide the network tariff upon which to base regulated retail tariff 54.

However, while there are a reasonable number of CAC customers (166) in Ergon Energy's East pricing zone, there are significantly less ICC customers (57) and only nine of these are on a regulated price. This highlights a problem with the N + R pricing approach that emerges as the size of the customer groups gets smaller as consumption levels increase.

The reality is that, for these customers (CAC and ICC), there is no such thing as a standard network tariff or charge that can usefully form the N component and be applied to all customers wanting supply under a notified price. This is because the consumption characteristics of these customers and the dedicated assets used to supply them become more varied and complex as the level of consumption increases. As a result, network businesses usually provide unique, one-off prices for CAC and ICC customers.

Using an average taken across these customer groups (as proposed) is not really a practical alternative because the wide range of customer characteristics that make up that average means that the average is hardly representative of the group. With small customers, this problem is not usually significant because there are generally large numbers of customers with roughly homogeneous consumption characteristics making up each tariff class.

For customers consuming more than 40 GWh, an average based on all ICC customers in Ergon Energy's East pricing zone would give a very different set of charges to an average based only on those ICCs in the East pricing zone who are actually on a regulated tariff and to whom these prices will apply. For this reason, the Authority has instead used the average of the charges for those ICCs currently on regulated prices in Ergon Energy's East pricing zone to arrive at the N component for customers consuming more than 40 GWh per year. This will provide the basis for regulated retail tariff 55.

While this provides a basis for setting regulated retail prices for this group of customers in this current exercise, the Authority does not consider this an entirely satisfactory outcome and is of the view that, as a minimum, customers consuming over 40 GWh per year in Ergon Energy's network area should be required to move to a market contract and regulated prices for these customers should no longer be published. Similarly, though slightly less pressing, customers in Ergon Energy's network area consuming between 4 GWh and 40 GWh per year should also be required to move to a market contract and regulated prices no longer be published for this group of customers. This is consistent with the Government's decision that large (consuming above 100 MWh per year) non-residential customers in the Energex network area will no longer have access to notified prices.

Energex raised similar concerns regarding the problems of coming up with network pricing options that could realistically serve as the basis for regulated retail prices for large and very large customers. Rather than using some average of current customer charges, Energex suggested that its HV Demand network tariff was the most appropriate (if not ideal) basis for establishing prices for this group of customers. Energex preferred this approach because its HV Demand charges are broadly similar, on an average c/kWh basis, to its charges for typical very large customers and this tariff is designed for customers connected to the high voltage network, is publicly available and is approved by the AER.

Nevertheless, this decision was made easier for Energex given that the Government's decision in relation to large customers in its network area would mean that this charge would never be applied in its network area as part of a regulated retail tariff.

2.1.3 The Authority's Draft Determination

The Authority's Draft Determination is to base regulated retail tariffs for 2012-13 on:

(a) Ergon Energy network tariffs and charges for non-residential customers with consumption greater than 100 MWh per year and for street lighting;

(b) Energex network tariffs and charges for all other customers, including unmetered loads other than street lighting; and

(c) a consumption-weighted average of rates for the first two steps of Energex's IBT for customers on card operated meters.

The resulting network charges to be used as the basis for regulated retail tariffs for 2012-13 are shown in Tables 2.2 to 2.4.

Table 2.2: Network Charges for 2012-13 Residential Regulated Retail Tariffs (GST exclusive)

Retail tariff	*Energex network tariff*	*Fixed charge* *c/cust/day*	*Variable rate (Flat)* *c/kWh*	*Variable rate 1*[a] *c/kWh*	*Variable rate 2*[b] *c/kWh*	*Variable rate 3*[c] *c/kWh*
Tariff 11 - Residential (inclining block)	8400	35.0		7.905	15.020	18.973
Tariff 12 - Residential (time-of-use)	8900	35.0		7.496	11.369	23.525
Tariff 31 - Night rate (super economy)	9000		4.161			
Tariff 33 - Controlled supply (economy)	9100		7.613			

a. First 13.69 kWh per day for Tariff 11, off-peak consumption for Tariff 12
b. Next 13.69 kWh per day for Tariff 11, shoulder consumption for Tariff 12.
c. Remaining kWh per day for Tariff 11, peak consumption for Tariff 12.

Table 2.3: Network Charges for Other 2012-13 Small Customer Regulated Retail Tariffs and Unmetered Supplies Other Than Street Lighting (GST exclusive)

Retail tariff	*Energex network tariff*	*Fixed charge*	*Demand charge*	*Variable rate (flat)*	*Variable rate (off peak)*	*Variable rate (peak)*
		c/cust/day	*$/kW/month*	*c/kWh*	*c/kWh*	*c/kWh*
Tariff 20 - Business (flat rate)	8500	64.0		10.152		
Tariff 22 - Business (time-of-use)	8800	64.0			8.451	10.341
Tariff 41 - Low voltage (demand)	8300	1501.0	17.753	1.017		
Tariff 91 – Unmetered	9600			8.137		
Card-operated meters (remote communities)	Based on 8400	35.0		10.339		

Note: Customers on card operated meters will pay the same charges for controlled load tariffs as residential customers.

Table 2.4: Network Charges for 2012-13 Large Customer Regulated Retail Tariffs and Street Lighting (GST exclusive)

Retail tariff	*Ergon Energy network tariff*	*Fixed charge*	*Demand charge*	*Capacity charge*	*Variable rate (flat)*
		c/cust/day	*$/kW/month*	*$/kW/month*	*c/kWh*
Tariff 42 - Over 100 MWh small (demand)	EDST1	494.900	27.115		1.579
Tariff 43 - Over 100 MWh medium (demand)	EDMT1	1995.000	23.307		1.579
Tariff 44 - Over 100MWh large (demand)	EDLT1	3271.800	22.336		1.579
Tariff 53 - High voltage (demand)	EDHT1	2059.500	17.890		1.541
Tariff 54 - Connection Asset Customers	EE CAC[a]	52492.900	5.246	10.713	0.811
Tariff 55 - Individually Calculated Customers	EE ICC[a]	245787.200	3.006	4.905	2.355
Tariff 71 - Street lighting[b]	EVUT1	23.900			9.253

a. *EE CAC and EE ICC are averages of the network charges Ergon Energy has for all of its CAC and non-market ICC customers in the East pricing zone.*
b. *The fixed charge for street lighting applies to each lamp, not each customer.*

2.2 Maintaining Alignment of Retail and Network Tariffs

As the Authority noted in its Issues Paper, adopting an N+R approach to setting regulated retail tariffs requires a formal process to ensure the ongoing alignment of network and retail tariffs to ensure the appropriate allocation of costs to (and recovery of costs from) groups of consumers covered by each tariff class. It would also ensure that distributors are able to engage in effective demand management initiatives that rely on price signals being passed through to customers.

The distributors' network prices are routinely approved by the AER just prior to the start of each financial year. Under the NER, the distributors are required to submit revised network prices at least two months prior to the commencement of the financial year. There is no formal limit under the NER on the time the AER can take to approve the pricing proposal.

The Authority is currently required to publish notified retail electricity prices to apply in the coming financial year by 31 May each year. Any change in the network tariffs proposed by the distributors and approved by the AER after the Authority had published final notified prices would potentially result in a misalignment of the two pricing structures.

2.2.1 Submissions

Submissions in response to the Authority's Issues Paper identified the following potential options for maintaining alignment between retail and network tariffs:

(a) request the AER to revise its processes in order to approve network prices earlier;

(b) adjust regulated retail prices to apply from 1 August each year instead of 1 July to accommodate potentially late approval of Energex network prices by the AER; and

(c) request Energex to supply the Authority with its proposed network tariffs and prices when they are submitted to the AER and use these as the basis for notified prices to apply from 1 July each year. Should there subsequently be any change to those proposed tariffs and/or prices, regulated retail prices could be adjusted after 1 July if necessary.

In its Draft Methodology Paper, the Authority noted that:

(a) Option (a) is problematic because the AER is required to adhere to price approval timeframes stipulated in the NER and therefore has no discretion to change its approvals process. The Authority could pursue changes to the timeframes in the NER with the Australian Energy Market Commission (AEMC), but it would seem unlikely that the price approval process in the NER, which applies nationally, would be altered to suit circumstances in one jurisdiction.

(b) Option (b) may be more feasible than option (a). However, while option (b) would eliminate the potential for notified prices changing more than once each year, it would require changes to State-based legislative arrangements (amendment of the Regulation to include a definition of a 'tariff year' as commencing from 1 August).

    Option (b) would also result in current notified prices remaining effective until 1 August each year but new network tariffs would be charged to retailers from 1 July. Attempting to incorporate a fair and reasonable allowance in the revised 1 August prices to compensate retailers for any loss during the month of July (or consumers for any loss should prices have been set too high) would be an issue.

(c) Option (c) may also be problematic because the National Energy Customer Framework (NECF) will allow changes to retail prices only once every six months. While it may be possible for the Queensland Government to opt out of imposing this restriction in Queensland, changing all notified prices twice in quick succession (as could potentially be required) would impose additional costs on retailers and increase the potential for confusion amongst consumers.

This is essentially the approach the Authority followed to date in determining the impact of network charges on retail prices under the BRCI. In practice there has not been a situation where network prices would have needed to be changed after July 1.

Given the difficulties associated with each of the available options and experience to date, the Authority proposed to adopt option (c).

There was general support in submissions on the Draft Methodology Paper for the Authority's proposed approach.

AGL, Origin Energy, the Queensland Council of Social Service (QCOSS) and Energex supported the Authority's proposed approach to ensuring the ongoing alignment of network and retail prices. AGL noted that, without a pass-through mechanism, retailers were exposed to the risk that the AER approves different network prices to those proposed by Energex and used for setting regulated retail prices. QCOSS suggested revising regulated retail prices only if the AER approved Energex network prices were materially different to those proposed.

However, the Chamber of Commerce and Industry Queensland (CCIQ) suggested that businesses generally had limited opportunity to pass on fluctuating costs and was therefore concerned about the impact of within-year price changes on businesses. CCIQ also suggested that the proposed retail margin already allowed for unforeseen and systematic risks faced by retailers. The Authority disagrees with this latter statement, since network costs are to be treated as a direct pass through to customers and are not considered in setting the retail margin, which covers risks associated with the R component of tariffs only. However, it does acknowledge that fluctuating electricity prices could impose a burden on other businesses (and households) and would prefer that (as in the past) regulated retail prices were able to be set prior to the start of the financial year and remain unchanged for the remainder of that year.

The Authority also acknowledges that not adjusting regulated retail tariffs to reflect any changes in network charges approved by the AER, as proposed by CCIQ, would impose a financial risk on retailers. It could also be seen as inconsistent with the requirement in the Delegation to implement an N+R approach to pricing where network costs are to be treated as a pass through.

The Authority is mindful that changing all notified prices twice in quick succession would impose additional costs on retailers and increase the potential for confusion amongst consumers. For this reason, the Authority sees some merit in QCOSS's suggestion to revise regulated retail prices only if the AER approved network prices were materially different to those proposed by the distributors and used as the basis for retail prices.

While option (c) remains the Authority's preferred approach, the NECF will only allow changes to retail prices once every six months. The Authority understands that the Queensland Government intends to opt out of imposing this restriction in Queensland. If this is the case, it would be possible to adjust notified prices at any time after 1 July if necessary.

2.2.2 The Authority's Draft Determination

In order to maintain alignment between distribution and regulated retail tariffs, the Authority has requested Energex and Ergon Energy to supply the Authority with the proposed network tariffs and prices they intend to submit to the AER, including:

(a) for Energex, all tariffs and prices except for those with site specific charges; and

(b) for Ergon Energy, tariffs and prices for SACs and street lighting in the East pricing zone, Transmission Region 1, and averages of the network charges for non-market CACs and ICCs in the East price zone.

The Authority has used these tariffs and prices as the basis for notified prices to apply from 1 July 2012.

The Authority considers that, should the need arise, regulated retail tariffs that apply from 1 July 2012 could be amended to reflect any material changes to network tariffs that are approved by the AER, including any adjustment to compensate retailers for altered network charges incurred by them prior to regulated retail tariffs being adjusted. However, as per the Delegation, the Authority's role in relation to setting notified prices for 2012-13 ends on 31 May 2012.

3. ENERGY COSTS

3.1 Introduction

Under the Delegation, the R component of each retail tariff is to include appropriate allowances for energy and retail costs.

The Delegation requires that the energy cost component of each regulated retail tariff should include the cost of purchasing energy, environmental and renewable energy costs, energy losses and NEM fees.

Specifically, the Delegation requires that, in calculating the energy cost component, the Authority must consider:

(a) the cost of energy;

(b) fees, including charges for market and ancillary services imposed by the AEMO under the NER;

(c) energy losses as published by AEMO;

(d) the likely impact resulting from Commonwealth legislation to put a price on carbon dioxide emissions;

(e) the efficient costs of meeting any obligations under environmental and energy efficiency schemes (including present and future State and Commonwealth schemes); and

(f) a mechanism to address any new compulsory scheme that imposes material costs on the retailer.

The Authority engaged ACIL to provide advice on each of these energy cost components. This chapter provides an overview of the approach proposed by ACIL and a summary of ACIL's findings. For more detail, see ACIL's reports to the Authority - *Estimated Energy Purchase Costs for 2012-13 Retail Tariffs* (ACIL Draft Report) and *Draft Methodology for Estimating Energy Purchase Costs* (ACIL Draft Methodology Report). Both are available from the Authority's website.

3.2 Wholesale Energy Costs

Wholesale energy costs (energy costs) relate to the costs incurred by a retailer in purchasing electricity to cover the load of its customers. While this electricity is ultimately purchased from the NEM (the spot market), there are a range of measures that a retailer can take in order to reduce its exposure to volatile prices in the spot market, including purchasing financial derivatives (futures, swaps, options etc.) to offset its exposure, entering longer-term power purchasing agreements with generators or investing in generation assets.

To arrive at its estimate of energy costs, the Authority must decide its general approach to estimating these costs and then, to implement its preferred approach, arrive at estimates of:

(a) forecast customer load profiles which must be supplied in 2012-13;

(b) the hedging strategy to be used in settling the forecast load(s) against the forecast prices;

(c) forecast energy spot prices to apply in 2012-13; and

(d) the cost of energy losses and carbon costs.

3.2.1 Approach to Estimating Wholesale Energy Costs

In its Issues Paper, the Authority identified that there are two broad approaches to estimating energy costs. A cost-based approach such as the long run marginal cost (LRMC) which estimates the costs of generation, or a market-based approach which estimates the costs a retailer would incur in purchasing electricity at prevailing market prices over a given period.

Under the BRCI, the Authority was required to consider both approaches and based its estimates of energy costs on a 50/50 combination of the outcomes from the two approaches.

In its Issues Paper (and previously in the 2009 Review), the Authority noted that its preference was to move to a solely market-based approach for estimating energy costs as it was of the view that this would better reflect the costs that a retailer is likely to incur in the relevant period. The Authority suggested that an approach similar to that used under the BRCI to estimate energy purchase cost appeared suitable for this purpose.

However, at the time of releasing its Draft Methodology Paper, uncertainty surrounding carbon costs for 2012-13 had led to a significant contraction in the level of electricity contracts traded on the Sydney Futures Exchange (SFE). This reduction in liquidity meant it was unlikely that the Authority could develop a robust market-based model for estimating 2012-13 energy costs similar to that adopted for estimating energy purchase costs under the BRCI.

As a result, for its Draft Methodology Paper, the Authority presented an alternative approach to estimating market-based energy costs - ACIL's proposed price distribution approach - which estimated the cost that a retailer would be willing to pay in order to hedge risks related to weather and generator outages based on a distribution of possible price outcomes for 2012-13.

Approaches in Other Jurisdictions

For its 2010-2013 retail electricity pricing decision for New South Wales, the Independent Pricing and Regulatory Tribunal (IPART)[5] used a hedging-based approach to estimate energy purchase costs and was required by its terms of reference to include LRMC as a floor price.

In its decision on retail electricity prices in the ACT for 2010-2012, the Independent Competition and Regulatory Commission[6] (ICRC) developed a model for estimating energy costs based on corporate finance concepts rather than a hedging strategy, reflecting the ICRC's concerns about the nature of the electricity market which made it impossible to perfectly hedge. In its December 2011 Issues Paper, the ICRC proposed to continue using this approach for the 2012-14 period.

In deciding on this approach, the ICRC noted that there were a number of reasons why the LRMC should not be used to estimate energy purchase costs. Amongst other things, the ICRC noted that the suggestion that generators would benefit from higher energy cost allowances in regulated retail tariffs, as a result of including LRMC in the calculation, was unproven and that higher energy cost allowances would not flow upstream to generators unless the retailer was altruistically supporting its suppliers. Furthermore, the ICRC considered that regulated retail prices should not be used to attempt to correct concerns about the long-term investment in electricity generation.

Due to insufficient liquidity in the contract market at the time, the Essential Services Commission of South Australia (ESCOSA) used a hybrid cost-based and market-based

[5] IPART, *Review of Regulated Retail Tariffs and Charges for Electricity 2010-2013, Final Report*, March 2010
[6] ICRC, *Retail Prices for Non-contestable Electricity Customers 2010-2012, Final Decision*, June 2010

approach to estimate energy costs in its price determination for 2011-14[7]. Specifically, ESCOSA developed low and high estimates of LRMC to provide a price floor and price ceiling for its market-based energy cost estimate, which was based on a weighted average of market contract prices.

Submissions

In response to the Issues Paper, retailers generally supported using a market-based approach, based on an assumed hedging strategy, to estimate energy costs, but raised two key concerns with that approach, including that:

(a) there was insufficient forward trading of electricity, due to uncertainty surrounding implementation of the proposed carbon tax, to use forward contract price data to estimate energy purchase costs; and

(b) electricity prices would become more volatile in future and that this volatility would be bad for consumers and retailers.

For these reasons, most retailers proposed that the energy cost estimate should also include LRMC, typically as a price floor. Retailers also suggested that using LRMC as a floor in the energy cost estimate would provide certainty to investments in electricity generation capacity.

In contrast to most retailers, consumer groups did not support using LRMC to estimate energy costs. For example, QCOSS (and Ergon Energy) supported using a pure market-based approach, with an assumed hedging strategy, to determine energy purchase costs, for the following reasons:

(a) the LRMC of generation is a theoretical concept and may not reflect the actual costs faced by retailers in purchasing wholesale energy in Queensland;

(b) calculating the LRMC of generation is opaque as it requires the Authority to rely on a consultant's 'black-box' model; and

(c) a market-based approach is based on transparent products that can be monitored and traded by all participants in the retail market.

Ergon Energy also argued that including an assumed hedging strategy was necessary because relying only on pool prices would introduce unacceptable volatility for retailers and consumers.

In response to the Authority's Draft Methodology Paper, there was very little support for ACIL's proposed alternate price distribution approach to calculating the cost of energy. Retailers and consumer groups alike raised a range of issues with the approach, in particular, that it lacked transparency, did not reflect retailers' actual costs and relied too heavily on complex black-box modelling.

In light of these concerns, alternative approaches to calculating wholesale energy costs were proposed. Consumer groups and Ergon Energy were generally in favour of a hedging-based approach, similar to that used for the BRCI. Ergon Energy suggested that increasing liquidity in the futures market was sufficient to develop a hedging-based approach for 2012-13.

In contrast, TRUenergy, AGL, QEnergy and Australian Power and Gas (APG) suggested that insufficient trading in energy forward contracts, due to uncertainty over the cost of carbon, precluded using a hedging-based approach for 2012-13. Instead, they proposed using an

[7] ESCOSA, *2010 Review of Retail Electricity Standing Contract Price Path, Final Inquiry Report and Final Price Determination*, December 2010

LRMC-based approach, arguing that many of the Authority's concerns about the LRMC approach applied even more to ACIL's price distribution approach.

Origin Energy, Alinta Energy and Stanwell suggested that a hybrid of LRMC and hedging-based costs would be appropriate for calculating wholesale energy costs for 2012-13.

The Authority's Position

LRMC

Despite the retailers' support for retaining at least some aspects of LRMC estimates in calculating energy purchase costs, there are a number of reasons to move away from using LRMC in favour of using a market-based approach, including that:

(a) LRMC is an estimate of generation costs rather than the cost to a retailer of purchasing wholesale electricity;

(b) LRMC ignores prevailing conditions in the electricity market, which can be influenced by a range of factors and which can have a significant influence on energy purchase costs; and

(c) LRMC ignores the existence of the NEM and the major impact it has had on the wholesale price of electricity.

The Authority is not convinced of the merits of including an LRMC "floor" for estimating energy prices. As noted in the Draft Methodology Paper, while adopting an LRMC floor in notified prices might provide additional security for investment in generation, the Authority is of the view that this is unnecessary given current market conditions as there appears to be sufficient reliable information available in the market for a firm to make a timely and efficient decision about investing in generation in the NEM.

Moreover, the Authority questions why this increased security would be needed with regulated prices but not if the market was entirely deregulated, in which case only market costs would be available. ACIL also advised against using LRMC on the basis that it does not account for prevailing market conditions and therefore is unlikely to reflect actual wholesale energy purchase costs faced by retailers, as required in the Delegation. Furthermore, the Authority considered that the ICRC's concerns regarding the use of LRMC were also relevant. For these reasons, the Authority has decided not to include estimates of LRMC in any way in its energy cost estimates for 2012-13 and will instead adopt a market-based approach.

Market-based Approaches

To help it form a view on which market-based approach to use, the Authority requested that ACIL develop energy cost estimates based on both the price distribution approach it proposed in its Draft Methodology Paper and a hedging-based approach similar to that used under the BRCI.

In response to concerns raised in submissions, ACIL further considered how its price distribution approach would be implemented. In its Draft Methodology Report, ACIL suggested that the approach recognised that a prudent retailer would hedge risks through energy purchase contracts and that this would incur extra costs, or a premium, over the expected spot market price.

In its Draft Report, ACIL further considered the issue of the risks faced by retailers and suggested that an efficient retailer would contract to a level where the exposure to high spot prices was kept to a level acceptable to the retailer, based on its appetite for risk and financial capability to ride out periods of high spot prices. However, ACIL stated that it was not able to estimate with any accuracy the extent to which the difference in risk aversion between retailers would affect the premium over the spot price that retailers would be willing to incur in purchasing forward energy contracts.

ACIL also investigated further the availability of data for use in a hedging-based approach to estimating energy costs. In addition to trading data from the SFE, ACIL reviewed trading information from two major broking firms, Tradition Financial Services (TFS) and ICAP. ACIL found that the levels of trading of 2012-13 base, peak and cap contracts in the d-cypha Trade futures market were comparable to those for previous years for all quarters except for base and peak contracts for the first two quarters of 2013. For these quarters, ACIL considered it could use the d-cypha Trade prices, but remove trades prior to the carbon tax legislation passing parliament[8] because, prior to this, it was difficult to ascertain what proportion of carbon costs were being passed through in the contract price. ACIL then used the broker data for carbon exclusive contracts for the 2013 calendar year (which had been trading well due to the AFMA pass-though clause) to verify that the d-cypha Trade data was reasonable. Taken together, ACIL was satisfied that the available data could be used in a hedging-based approach to estimate energy costs for 2012-13.

Given its difficulties in calculating a premium to reflect retailers' risk appetite and its favourable review of available market data, ACIL recommended that the hedging-based approach be used to estimate energy purchase costs for 2012-13 and in future years. The only exception to this was for controlled load and unmetered supply tariffs where ACIL suggested that the hedging-based approach was not suited to estimating energy costs because the loads for these tariffs mainly occur in off-peak periods which are difficult to cover with base, peak or off-peak contracts without significantly over-contracting. ACIL also noted that unpredictable pool price spikes would be extremely rare during the off-peak times applicable to these tariffs. For these reasons, ACIL suggested that energy costs for controlled load and unmetered supply tariffs be based on forecast pool prices and suggested that the mean energy cost estimates for these tariffs from its price distribution approach would be suitable.

As the Authority indicated in its Draft Methodology Paper, it only proposed using ACIL's price distribution approach to estimate energy costs for 2012-13 because, at that time, it appeared there would be insufficient market data to support continued use of a BRCI-type hedging-based approach. Nevertheless, the Authority noted its preference for the continued use of this type of approach because it had been developed over a number of years, was generally supported by stakeholders and was relatively transparent and intuitive.

In light of ACIL's further review of energy contract data indicating that there is sufficient data now available to produce reasonably robust energy cost estimates for 2012-13, and noting that an additional 10 weeks of data will be available for use in preparing the Final Determination, the Authority has decided to use a hedging-based approach to estimate energy costs for 2012-13.

The Authority agrees with ACIL that it seems reasonable to assume that retailers would not need to hedge their loads for controlled load and unmetered supply tariffs, given the very low likelihood of pool price spikes during times when these tariffs mainly apply. The Authority has therefore decided to calculate wholesale energy costs for controlled load and unmetered supply tariffs based on forecast pool prices for 2012-13.

An outline of ACIL's analysis and results for the hedging-based approach is provided below. For completeness, the Authority has also included an overview of ACIL's price distribution approach and results at **Appendix F**. Interestingly, both approaches produce broadly similar

[8] The Clean Energy Future legislation passed the Federal Parliament on 8 November 2011.

results. A more detailed discussion of both approaches can be found in ACIL's Draft Report which is available from the Authority's website.

3.2.2 Customer Load Forecasts

To undertake its analysis of energy costs, the Authority requires forecasts of customer loads that will need to be purchased by retailers in 2012-13.

Under the BRCI, the Authority was required to use the 'NEM load' (being the total State NEM load less the load of customers directly connected to the transmission network) to calculate energy cost estimates. As the BRCI involved escalating all tariffs by a single rate, there was no need to calculate energy costs by tariff or settlement class.

In its Issues Paper, the Authority suggested that it would be necessary to estimate the load of customers in aggregate and on each network tariff in Energex's network area in order determine energy costs.

At that time, the Authority proposed to use the Energex net system load profile (NSLP) for estimating energy costs for regulated retail tariffs as stakeholders had generally supported the use of this load profile when the Authority undertook the 2009 Review.

In its Draft Methodology Paper, the Authority noted the suggestion by ACIL that, in conjunction with its price distribution model, it could develop separate load forecast for each regulated retail tariff. At that time, the Authority was of the view that this should improve the cost-reflectivity of the subsequent retail tariffs.

The Authority also noted that there were a series of other factors that it would have to consider prior to releasing its Draft Decision, including:

(a) how best to cater for large customers in Ergon Energy's distribution area consuming more than 4 GWh per year;

(b) what impact the imposition of an inclining block tariff for residential consumers would have on the load profile for this tariff; and

(c) how to estimate the load profile for those residential customers that chose to take-up the option of a voluntary time-of-use tariff and what impact this may have on the load profile for the remaining inclining block customers.

Finally, the Authority proposed to use the forecasts published in AEMO's Electricity Statement of Opportunities (ESOO) to escalate historic load profiles to reflect the demand and volume expectations for 2012-13.

Approaches in Other Jurisdictions

In their most recent determinations, ESCOSA and ICRC both used the NSLP as the basis for their energy cost estimates. As required by their respective terms of references and regulations, IPART and the Office of the Tasmanian Economic Regulator (OTTER) both used the forecast load of contestable customers provided by the incumbent retailers in their regions. However, IPART also made a recommendation to the NSW Government that it consider amending the terms of reference for future price reviews to allow energy purchase costs to be based on the NSLP of each of the NSW Standard Retailers, rather than on the Standard Retailer's own forecasts of contestable customer load.

Submissions

In response to the Issues Paper, retailers suggested that, subject to some adjustments, Energex's NSLP was the most appropriate source of data for customer load forecasts. Origin Energy, AGL and TRUenergy all suggested that, if applied, the Energex NSLP should be adjusted to account for the required transfer of large customers (those customers that consume more than 100 MWh per annum) off notified prices and onto negotiated retail contracts.

Submissions received in response to the Draft Methodology Paper were critical of the Authority's proposal to estimate energy costs based on the consumption patterns of customers on each retail tariff. Retailers and consumer groups considered that the NSLP was more appropriate because it is the basis upon which retailers' purchases are settled by AEMO and that using loads for individual tariffs would introduce unwanted distortions between customer classes that are all settled against the same load profile by AEMO.

AGL reiterated its view that the Authority should remove large customers consuming more than 100 MWh per annum from Energex's NSLP because these customers will be removed from the NSLP in 2012-13 when they can no longer access notified prices. Ergon Energy supported using Energex's NSLP to estimate energy purchase costs, but suggested that the Authority should use a historical trend analysis to adjust the NSLP rather than the ESOO, which Ergon Energy suggested had overestimated electricity demand and consumption in Queensland over the last few years.

The Authority's Position

Settlement Classes vs. Individual Load Profiles

In response to concerns raised in submissions, the Authority agrees that the manner in which energy costs are settled by AEMO provides the most appropriate basis for estimating energy costs. The Authority has therefore determined energy costs based on load profiles for AEMO 'settlement classes' in order to reflect the actual costs incurred by retailers.

Under the AEMO settlement process, the majority of customers' consumption is settled against the NLSP for each distributor because the majority of individual customer meters are simple accumulation meters and do not provide any information on the time of use, only the amount of energy consumed over an extended period (generally each quarter). Where customers have time-of-use meters that record both time and quantity data or this can be implied from the tariff type (for example, controlled loads), this information is used to settle the retailer's energy costs. However, it should be noted that many "time-of-use" tariffs for small customers are still settled against the NSLP as the meters are either not capable of recording sufficient time and usage data or the meter is simply being read as if it were an accumulation meter.

Therefore, the NSLP has been used as the basis for estimating energy costs for all those tariffs that are settled against the NSLP by AEMO. This means that a single flat energy cost component will apply across all time periods in order to avoid creating cross-subsidies between regulated retail tariffs. Similarly, as all consumption on the residential IBT will be settled against the NSLP, a single flat energy cost component will apply across all consumption blocks.

This approach means using the Energex NSLP and two controlled load profiles as the basis for estimating energy costs for regulated retail tariffs for small customers and the Ergon Energy NSLP as the basis for estimating energy costs for regulated retail tariffs for large customers (which the Authority has decided to base on Ergon Energy network tariffs, as discussed in Chapter 2).

The Authority has also used the load profile for unmetered consumption in Energex's area as the basis for estimating energy costs for unmetered and streetlight tariffs. While the Authority would have preferred to base the streetlight tariffs on the load profile of streetlight customers in Ergon Energy's area, Ergon Energy was unable to provide this information. In the absence of actual load data from Ergon Energy, ACIL considered that the Energex unmetered load profile provided a reasonable approximation of that which would be likely to apply in the Ergon Energy area as these loads appear fairly similar given the nature of the activities being supplied.

Potential Adjustments to Energex NSLP

The Authority has also considered whether it should adjust the Energex NSLP to account for:

(a) the introduction of the residential IBT;

(b) the introduction of the voluntary residential time-of-use tariff; and

(c) the removal of large customers from accessing notified prices in the Energex area.

While the IBT may provide an incentive for some consumers to reduce their total consumption, it does not provide any incentive for consumers to modify the timing of their consumption, and therefore impact the profile of the NSLP. For this reason, the Authority does not expect the introduction of the residential inclining block tariff to impact the Energex NSLP.

Only customers with relatively high levels of consumption who are willing and able to shift their consumption from peak to off-peak periods of the day are likely to benefit from moving to the time-of-use tariff. Moreover, the distributors will have constraints on how many new time-of-use meters they can install over the year to accommodate demand from customers wishing to switch to this tariff. As a result, the likely take-up of the residential time-of-use tariff will be relatively slow at first and the Authority does not expect its availability to impact the NSLP in any measurable way in 2012-13.

Regarding the impact of large customers being required to move from notified prices to market contracts, Energex has indicated that this is likely to have less than a 1% impact on the NSLP because the majority of large customers in the Energex area are already outside the NSLP and are being settled against their individual interval meter readings.

For these reasons, the Authority has decided not to make any one-off adjustments to the Energex NSLP.

Period of Historic Load Used

At the workshop, stakeholders suggested that ACIL's approach of constructing 41 years of load data from a single year of actual data could produce skewed outcomes if the actual data was based on a particularly cool or hot year.

While ACIL was satisfied that this was not the case, it has modified its approach to base its load forecasts on four years of actual historical data – 2007-08 to 2010-11. Including the additional actual load data reduces the number of years of 'constructed' load data that needs to be developed to 37 years.

As Queensland has seen some unusual weather events over the last few years, using four years of actual load data should further reduce any possible impact that these weather events may have on the constructed load profiles and, in turn, the energy cost estimates.

Escalating Load Profiles to 2012-13

At the time of the Draft Methodology Paper, ACIL proposed to adjust consumption and demand estimates for Queensland and other NEM regions according to the ESOO forecasts (which are based on the forecasts in Powerlink's Annual Planning Report (APR). For tariff-specific load profiles, it proposed to use 2012-13 forecasts provided by the distributors.

Since the release of the Draft Methodology Paper, Powerlink has published revised forecasts for 2012-13[9]. These latest forecasts are not yet reflected in the ESOO but represent the most up to date Powerlink forecasts and appear to be more consistent with past experience. In escalating loads to 2012-13, ACIL has used these latest Powerlink forecasts rather than the older ESOO forecasts. The revised forecasts are considerably lower than those previously published by Powerlink (and included in the ESOO), which goes some way to addressing concerns raised by stakeholders that Powerlink had a history of over-estimating future demand.

As energy components will now be estimated according to settlement class, ACIL used the region-specific forecasts in the updated APR and applied them to the relevant load profiles.

Load Forecasts

For the purpose of estimating energy purchase costs under the BRCI, ACIL forecast three load profiles using the NEM load for the 12 months to 31 March preceding the commencement of the tariff year, escalated to reflect the 10%, 50% and 90% probability of exceedance (POE) forecasts in the ESOO for the upcoming tariff year.

To estimate energy costs for 2012-13, the Authority needs to develop forecast half-hourly load profiles for each of the relevant settlement classes – the Energex NSLP and the two Energex controlled loads, the Ergon Energy NSLP and the Energex unmetered tariff load.

In its Draft Report for 2012-13, ACIL has used 41 years of weather data (1970-71 to 2010-11) and four years of load data (2007-08 to 2010-11) to "construct" 37 additional years of weather adjusted load data for each settlement class. To construct the 37 additional years of load data, ACIL matched the weather on each day of the additional years with the weather on one day in the four sample years to find the closest match (using a least squares approach). Having matched each day in the additional years with one day in the sample year, ACIL applied the load from the day in the sample year to the corresponding day in the additional year. Once it had constructed the 37 years of additional load data, ACIL then escalated each of the 41 load profiles to reflect forecast consumption in 2012-13.

ACIL then took the median load profile (from the 41 weather-adjusted annual load profiles for 2012-13) for each settlement class as the basis for estimating the volume of hedging contracts a retailer would need to purchase in order to meet those forecast loads.

3.2.3 Hedging Strategy

Having arrived at the forecast load profiles for each settlement class, the next step is to determine a reasonable hedging strategy that a retailer might adopt in purchasing forward contracts to supply those loads.

The basis of the hedging strategy used here is the same as that used previously for the 2011-12 BRCI Final Decision, in that it assumes that a retailer would purchase:

(a) flat swaps up to the 80th percentile of off-peak load. (A 1 MW quarterly flat swap contract is an agreement between two parties to sell/buy 1 MW of electricity in each hour over the quarter);

(b) peak swaps beyond the level of flat swaps up to the 90th percentile of peak load. (A 1 MW peak swap contract is an agreement between two parties to sell/buy 1 MW of

[9] Powerlink, *Annual Planning Report 2011 Update*, January 2012

electricity for each hour between 7am and 10pm weekdays (excluding public holidays) over the duration of the quarter); and

(c) $300 caps beyond the cover of swaps to cover up to 105% of the maximum peak load. (Cap contracts only pay out when the spot price is above a particular price. For example, if a retailer purchases a $300 peak cap contract, it will face the spot price whenever the spot price is under $300/MWh but a maximum of $300/MWh at all other times).

However, rather than assuming that a retailer would spread its contract purchases evenly over 24 months up to the start of the tariff year (as was assumed under the BRCI), in applying the hedging strategy for 2012-13, ACIL has assumed that a retailer would spread its energy purchases over a four-year period and, in order to reflect the shortage of contract trading in some periods as discussed above, has used a volume-weighted average of energy purchases over that period rather than assuming an even purchasing pattern as was done previously. There was general agreement at the workshop that a longer time period would better reflect the actual hedging strategies of retailers. While three years was suggested at that time, the move to four years will pick up all possible trading in hedging contracts. Combined with the move to volume weighting, this should produce a better representation of contract purchasing patterns.

An approach along these lines was supported at the workshop and in submissions and ensures that the relative value of trades in the market is reflected in the energy cost estimate.

As noted above, the cost of purchasing the required hedging contracts to cover the forecast loads is based on d-cypha Trade contract price data.

3.2.4 Spot Price Forecasts

While the previous two sections provide estimates of the forecast load and the cost of hedging contracts to cover that load, the actual outcome for the year in prospect (and hence the estimated cost of energy) will also be influenced by how well those forward purchases cover the actual load and the costs a retailer might incur due to its exposure to the spot market prices whenever its hedged coverage falls short of what is actually required or proves to be excessive.

While a retailer will typically try to purchase contracts to cover its forecast load as closely as possible, the inflexible nature of exchange traded contracts means that retailers will always have periods in which they are either over- or under-contracted. At these times, the retailer is exposed to the prices in the spot market.

Forecasting wholesale spot market prices with any degree of accuracy and credibility invariably requires the use of a proprietary electricity market simulation model, capable of simulating spot prices that would occur in the NEM.

Approaches in Other Jurisdictions

Previously, the Authority (in its BRCI decisions), IPART and ESCOSA have relied on expert consultants' proprietary electricity market simulation models to generate future spot prices. In its 2010-12 decision, the ICRC adopted a simpler modelling approach, relying on historical spot price outcomes against which it modelled forward contract prices.

Submissions

In response to the Issues Paper, AGL, Origin Energy and Ergon Energy favoured the use of forecast spot prices rather than historical prices. While each noted some of the shortfalls of proprietary models (largely relating to the subjectivity of assumptions and lack of transparency), it was considered that these models were favourable to using historical prices that are unable to take account of future market conditions (such as the introduction of a carbon tax).

QCOSS suggested that the Authority should not adopt a methodology that relied on a proprietary model that was not open for review and auditing. Rather, it suggested the Authority should adopt an approach similar to that followed by ICRC, which used transparent and publicly available historical spot prices.

QEnergy suggested that it was not necessary to develop spot price forecasts because, when businesses expose themselves to the spot market, they do it for speculative/trading reasons. QEnergy suggested that regulated retail tariffs should not account for activities that are unrelated to retailing.

Following the release of the Draft Methodology Paper, only AGL and Ergon Energy commented on the approach to forecasting spot prices. AGL reiterated its support for spot price forecasts (as opposed to the use of historical data) to the extent that they are used to settle financial contracts. Ergon Energy also supported the use of forecasts, but noted that the physical and financial markets are not perfectly correlated and that in most quarters there is a negative correlation between contract and spot prices (in periods where financial contracts were trading at higher prices, generators tend to contract a higher proportion of their load which reduces pool prices).

The Authority's Position

While the Authority considers that the spot price is a key input to estimating the energy costs that a retailer is likely to face, it acknowledges that proprietary spot price forecasting models can be opaque and that some stakeholders would prefer an approach to determining spot prices that can be independently verified through publicly available data. However, using historical prices does not appear to be a viable alternative as this would ignore structural changes that might be reasonably expected to occur in the market in the future, for example, the likely imposition of a carbon tax on 1 July 2012.

As proposed in the Draft Methodology Paper, ACIL has used its Powermark proprietary model to develop NEM spot price forecasts for 2012-13. ACIL's model takes the 41 half-hourly load profiles for the NEM together with 10 generator outage scenarios to produce 410 half-hourly annual spot price scenarios for 2012-13. These scenarios reflect a range of potential load and spot price outcomes that may occur in 2012-13.

Under the BRCI, ACIL used three load and spot price scenarios (10%, 50% and 90% POE) to arrive at its estimate of energy costs for the following year. Under this new approach, ACIL uses 41 load scenarios and 410 spot price scenarios to better reflect the range and relative likelihood of costs being incurred by a retailer.

For each half-hour in the forecast year (2012-13), ACIL brings together the hedging costs for each settlement class (from section 3.2.3), the load forecasts (from section 3.2.2) and the spot price estimates (from section 3.2.4) to estimate the cost that a retailer would incur in that half hour. For each spot price scenario, ACIL then estimates the load-weighted average price that a retailer would pay over the year, resulting in 410 load-weighted average prices for 2012-13. It then takes the simple average of these to arrive at its estimate of the wholesale energy cost for 2012-13.

Table 3.1 shows the basic wholesale energy cost estimates for each settlement class in 2012-13.

Table 3.1: Wholesale Energy Cost allowances for 2012-13 Excluding Losses and Carbon

Settlement class	*Retail Tariff*	*Allowance ($/MWh)*	*Allowance (c/kWh)*
Energex NSLP	11, 12, 20, 22, 41	41.60	4.160
Energex Controlled Load 9000	31	21.39	2.139
Energex Controlled Load 9100	33	28.59	2.859
Ergon Energy NSLP	42, 43, 44, 53, 54, 55	35.15	3.515
Energex Unmetered Supply	71, 91	22.10	2.210

Source: ACIL Tasman, Estimated Energy Purchase Costs for 2012-13 Retail Tariffs, March 2012.

3.2.5 Energy Losses

In delivering energy from a generator to a consumer, some losses occur. A retailer must purchase sufficient energy to supply its customers and allow for the transmission and distribution losses that will be incurred.

Under the BRCI, the Authority accounted for transmissions losses, but not distribution losses, on the basis that its energy cost estimate was based on the NEM load which included distribution losses but excluded transmissions losses. To account for transmission losses, the Authority increased energy cost estimates by the average loss factors published by Powerlink in its Annual Planning Report.

Submissions

In response to the Issues Paper, Origin Energy, TRUenergy, QEnergy, Ergon Energy and QCOSS all suggested that the Authority should take account of both transmission and distribution losses in the Energex area.

Ergon Energy suggested that the Authority adopt loss factors published by AEMO and that the highest transmission loss factor in the Energex area and the Energex distribution loss factors that apply to each customer type would be the most appropriate.

QCOSS also suggested that the transmission loss factors that AEMO publishes would be the most appropriate to use and that the AER-approved loss factors were most appropriate for distribution losses.

Following the release of the Draft Methodology Paper, submissions were generally supportive of the Authority's proposed treatment of energy losses which reflected suggestions made in submissions.

The Authority's Position

The Delegation requires the Authority to use the loss factors published by AEMO. The Authority has therefore used the most recent transmission loss factors and AER-approved distribution loss factors that are available from the AEMO website at the time of preparing its Draft Determination.

In its Draft Methodology Paper, the Authority proposed to only use Energex loss factors because, at that stage, all tariffs were to be calculated based on the Energex network tariffs and the load of customers in the Energex area.

As the Authority is now basing some tariffs for large customers on Ergon Energy network tariffs and charges, it has also used the corresponding energy loss factors for the Energex and Ergon Energy areas in calculating the accompanying energy costs.

Table 3.2 shows the loss factors that have been applied to the different energy cost estimates.

Table 3.2: Energy Loss Factors for 2012-13

Settlement class	*Retail Tariff*	*Transmission and distribution losses*
Energex NSLP	11, 12, 20, 22, 41	7.4%
Energex Controlled Load 9000	31	7.5%
Energex Controlled Load 9100	33	7.5%
Ergon Energy NSLP	42, 43, 44, 53, 54, 55	8.0%
Energex Unmetered Supply	71, 91	7.5%

Source: ACIL Tasman, Estimated Energy Purchase Costs for 2012-13 Retail Tariffs, March 2012.

3.2.6 Carbon Costs

In the Issues Paper, the Authority noted that, if a carbon tax were to be implemented by the Commonwealth Government from 1 July 2012, the costs associated with this tax would need to be accounted for in its energy purchase cost estimates.

Approaches in Other Jurisdictions

A number of regulators in other jurisdictions have considered the likely impacts of a carbon tax on regulated retail tariffs.

Throughout the early stages of the most recent reviews by ESCOSA, ICRC, IPART and OTTER, the Carbon Pollution Reduction Scheme (CPRS) was expected to take effect from 1 July 2011. ESCOSA, IPART and OTTER each estimated the likely impacts of carbon costs on regulated retail tariffs according to Commonwealth Treasury forecasts and their own estimates. ICRC noted that it would reassess its estimates in time for the beginning of the 2011-12 year.

While the CPRS was postponed prior to any of these determinations taking effect, ESCOSA, IPART and OTTER each included a re-opening clause in their determinations to allow them to take into account changes to carbon policies that may take effect in the future.

Submissions

Submissions received in response to the Issues Paper generally supported including an allowance for carbon costs in the 2012-13 regulated retail tariffs. Retailers suggested that the Authority should estimate a pass through for carbon costs separate to the energy cost allowance. AGL suggested that the Authority adopt the approach outlined in the Australian Carbon Benchmark (ACB) Addendum that AFMA published, which estimates carbon costs according to \$23 per tonne multiplied by the average emissions intensity of generators in the NEM.

Following the release of the Draft Methodology Paper, retailers generally favoured this approach.

QCOSS suggested that carbon costs should be accounted for in the energy cost estimates and should not be a direct pass through. The Queensland Farmers Federation suggested that the Authority should also take into account the various compensation measures that were included in the Clean Energy Future legislation.

The Authority's Position

As proposed in the Draft Methodology Paper, the Authority has prepared two sets of hedging-based energy costs – one set that is carbon exclusive and one set that is carbon inclusive.

To estimate the cost of carbon, ACIL applied the AFMA ACB addendum methodology and estimated that the average intensity of NEM generation will be 87% for 2012-13. At the legislated carbon tax rate of $23 per tonne, ACIL estimates carbon costs to be $20/MWh on generated energy for 2012-13. Table 3.3 provides 2012-13 carbon costs once the flat $20/MWh has been adjusted for the specific network losses and the holding costs for each settlement class.

Table 3.3: Carbon Costs for 2012-13

Settlement class	*Retail Tariff*	*Carbon costs ($/MWh)*
Energex NSLP	11, 12, 20, 22, 41	$21.48
Energex Controlled Load 9000	31	$21.74
Energex Controlled Load 9100	33	$21.74
Ergon Energy NSLP	42, 43, 44, 53, 54, 55	$21.60
Energex Unmetered Supply	71, 91	$21.74

Source: ACIL Tasman, Estimated Energy Purchase Costs for 2012-13 Retail Tariffs, March 2012.

Given that the Clean Energy Futures legislation was passed by the Commonwealth in November 2011, it is now almost certain that the carbon tax will take effect from 1 July 2012. As a result, the Authority has based its Draft Determination on ACIL's carbon-inclusive energy cost estimates for 2012-13.

3.2.7 Wholesale Energy Costs for 2012-13 Including Losses and Carbon

Based on the above discussion, Table 3.4 shows the proposed wholesale energy cost allowances for each settlement class in 2012-13.

Table 3.4: Wholesale Energy Cost allowances for 2012-13 Including Losses and Carbon

Settlement class	*Retail Tariff*	*Allowance ($/MWh)*	*Allowance (c/kWh)*
Energex NSLP	11, 12, 20, 22, 41	66.13	6.613
Energex Controlled Load 9000	31	44.99	4.499
Energex Controlled Load 9100	33	52.82	5.282
Ergon Energy NSLP	42, 43, 44, 53, 54, 55	59.57	5.957
Energex Unmetered Supply	71, 91	45.76	4.576

Source: ACIL Tasman, Estimated Energy Purchase Costs for 2012-13 Retail Tariffs, March 2012.

3.3 Other Energy Costs

In addition to wholesale energy costs, the Delegation requires that the Authority also consider other costs that a retailer might incur, including fees and charges imposed by AEMO, the efficient costs of meeting any obligations under environmental and energy efficiency schemes (including future State and Commonwealth schemes) and a mechanism to address any new compulsory scheme that imposes material costs on retailers.

The Authority has considered additional energy costs that retailers incur in relation to:

(a) the Queensland Gas Scheme;

(b) the Small-Scale Renewable Energy Scheme (SRES);

(c) the Large-Scale Renewable Energy Target (LRET) Scheme; and

(d) NEM participation fees and ancillary services charges.

The Authority has considered inclusion of a mechanism to address any new compulsory scheme that imposes material costs on retailers in Chapter 6, but concluded that it was not able to do this.

3.3.1 Queensland Gas Scheme

The Queensland Gas Scheme requires retailers to obtain and surrender sufficient Gas Electricity Certificates (GECs) to cover a prescribed proportion of their annual customer load or incur a penalty charge for each MWh shortfall. The requirement to obtain GECs therefore creates an additional cost to retailers in purchasing electricity for their customers.

When a national emissions trading scheme was previously proposed, the Queensland Government indicated that the Queensland Gas Scheme may be phased out. With the introduction of the carbon tax now imminent, it is still not clear whether the Queensland Gas Scheme will be removed. However, until there is a clear commitment to remove the scheme, retailers will continue to incur Gas Scheme costs and the Authority is bound to include these costs in its estimate of energy costs.

To effectively estimate the cost of complying with the Queensland Gas Scheme, the following information is required:

(a) the annual mandatory targets to be covered by GECs in 2012 and 2013; and

(b) the cost of obtaining GECs to meet those targets.

The annual mandatory targets are prescribed under the Electricity Act. In 2012 and 2013, a retailer is required to obtain GECs equivalent to 15% of its annual electricity load[10].

In the absence of information from retailers about their actual GEC costs, the Authority has used different approaches in the past to estimate GEC costs. The Authority has preferred to use a market-based approach to estimating these costs. In its 2011-12 BRCI decision, the Authority considered a suggestion from retailers that it adopt an approach based on the LRMC of gas-fired generation plant, but dismissed this idea on the basis that the LRMC approach would be less transparent and potentially more complicated than a market-data based approach.

Submissions

In response to the Authority's Issues Paper, several retailers were critical of using current market data to estimate GEC costs due to insufficient liquidity in the GEC market. Some retailers also suggested that current market data did not reflect the cost to retailers of purchasing GECs through long-term supply contracts between retailers and eligible generators.

In contrast, QCOSS supported estimating GEC costs using market prices, arguing that these best reflected the actual costs faced by retailers. APG was also of the view that, in its opinion, there was sufficient market data for the Authority to estimate compliance with environmental schemes.

Reflecting concerns about the lack of available market data, a number of submissions proposed using a longer time series of data than the Authority had previously used under the BRCI.

As an alternative to the market-based approach, Origin Energy suggested that the Authority adopt the LRMC of gas-fired generation to calculate GEC costs while AGL suggested consideration of a 'portfolio cost' approach, incorporating other sources of compliance.

Following the release of the Authority's Draft Methodology Paper, QCOSS disagreed with the Authority's proposal to estimate GEC costs using a longer time series of data (as had been suggested by others), on the basis that the GEC market is currently oversupplied and that using a longer time series would therefore over-estimate the price of GECs paid by an efficient retailer.

The Authority's Position

The Authority considers that information on long-term GEC contracts would be a preferable basis for estimating future costs rather than using available market data. However, as noted by ACIL, this information is unavailable and the available market data is the only source of information on GEC costs.

The alternative of using an approach based on the LRMC of gas-fired generation has been considered by the Authority previously and found to be inferior to the more transparent and less complicated market-data based approach.

However, the Authority notes the concerns expressed by retailers about the current low levels of liquidity in the market for GECs, given that the market is characterised by a relatively small number of participants purchasing certificates that are created monthly at most and surrendered only once each year. Given that GECs have been acquired by various means, including long

[10] http://www.energyfutures.qld.gov.au/gas/qld-gas-scheme.htm

term contracts, and the fact that the GEC market is now oversupplied with low prices and very thin trading it would be appropriate to extend the historical period over which GEC prices are determined.

In calculating the 2011-12 BRCI, the Authority also considered that the movement in GEC prices would be better represented by a longer term view of market prices. However, at the time the 2011-12 decision was made, which required calculation of GEC costs for 2010-11, there was only sufficient market data to enable GEC costs to be calculated using a two year averaging period (with data from 1 July 2007). As another year has passed, there is now more historical market data available. The Authority has therefore extended the period over which GEC market prices are to be averaged from the two years used previously out to four years. Using this extended period of data will help to smooth some of the unusual movements in market prices.

Based on current market data and the requirement for retailers to obtain GECs for 15% of their annual electricity load in 2012-13, the Authority has estimated the cost of complying with the Queensland Gas Scheme for 2012-13 to be $0.86/MWh[11].

3.3.2 Enhanced Renewable Energy Target Scheme

On 1 January 2011, the Renewable Energy Target scheme was split into two separate schemes – the SRES and the LRET scheme, collectively known as the Enhanced Renewable Energy Target (ERET) Scheme.

The LRET sets annual targets for the amount of electricity that must be generated by large-scale renewable energy projects, such as wind farms. Retailers must purchase a set number of Large-Scale Generation Certificates (LGCs) determined by the Office of Renewable Energy Regulator (ORER) on the basis of achieving the annual target. The number of LGCs required to be surrendered by retailers to discharge their liability each year is determined by ORER's Renewable Power Percentage (RPP).

The SRES covers small-scale technologies such as solar panels and solar hot water systems installed by households and small businesses. Retailers must purchase Small-scale Technology Certificates (STCs) based on the expected rate of STC creation, which is determined by ORER's Small-scale Technology Percentage (STP).

Retailers are required to surrender STCs and LGCs to fulfil their annual ERET obligations. If a retailer fails to meet its obligations, it will incur a penalty.

LRET Costs

For the 2011-12 BRCI, the Authority used a market-based approach to estimate LRET costs. The Authority based its estimate of 2011 LRET costs on weekly market prices for LGCs published by AFMA and the latest RPP and annual LRET targets set by ORER. For 2012, ACIL estimated total liable energy and used the latest published LRET target to arrive at a forecast RPP.

Approaches in Other Jurisdictions

The ICRC (ACT) and OTTER (Tasmania) adopted market-based approaches to estimating retailers' cost of complying with the LRET scheme in their most recent determinations. While the ICRC estimated the cost of LGCs based on its regulated retailer's over-the-counter trades, OTTER estimated LRET costs based on its regulated retailer's forward purchasing strategy.

[11] The cut-off date for AFMA data used is 18 January 2012. The date will be extended to 31 March 2012 for the Final Determination.

IPART (NSW) and ESCOSA (South Australia) based their cost estimates on the LRMC of renewable generation in their most recent determinations. While IPART estimated the cost of LGCs based on the LRMC of meeting the overall LRET target, ESCOSA estimated the cost of LGCs based on the difference between the LRMC of a new entrant wind generator and a Combined Cycle Gas Turbine generator.

All four regulators applied ORER's published and forecast RPPs in estimating LRET costs.

Submissions

Submissions in response to the Authority's Issues paper had different views as to how LRET costs should be estimated. AGL, Origin Energy and TRUenergy suggested that LGC prices should be based on the LRMC of wind powered generation mainly reflecting their concerns about the current lack of liquidity in the market for LGCs.

Despite its preference for using an LRMC approach, AGL acknowledged that a market-based approach was a transparent way to determine short-term compliance costs but that other options for retailers to comply should be taken into account. AGL also considered that the LRET market was temporarily oversupplied and suggested that the Authority should not place too much weight on market prices.

In contrast, Ergon Energy, APG, QEnergy and QCOSS preferred a market-based approach. Ergon Energy further suggested that the Authority should calculate LGC prices using a 12 month average based on market price data published by AFMA/Intercapital Plc.

Following the release of the Authority's Draft Methodology Paper, AGL and Origin Energy reiterated their support for the LRMC approach on the basis that it better reflected retailers' costs.

QCOSS supported the proposal to continue using a market-based approach. Notwithstanding its support for the LRMC approach, Origin Energy suggested that, if the market-based approach were to be used, the Authority should calculate LGC prices using only an 18-month average of market price data commencing 1 January 2011 (which reflects the commencement of the ERET scheme) as prices were depressed immediately prior to this date.

The Authority's Position

The Authority considered whether an LRMC based approach should be used in its 2011-12 BRCI Decision but determined that it was more appropriate to use actual market data than supply proxies such as the LRMC. The Authority has not been persuaded to change that view.

Although ACIL noted that retailers acquire most of their LGCs through long-term contracts with wind farms or through direct wind farm ownership, the prices in these contracts are not publicly available. Therefore, the Authority has to rely on market prices for LGCs published by AFMA.

While some retailers noted that there is a lack of liquidity in the market for LGCs, a low volume of trading does not necessarily mean market prices are unreliable. Following an examination of market prices over recent years, ACIL concluded that the market price has reacted as one would expect to prevailing market conditions. Nevertheless, in recognition of the current lack of liquidity, ACIL averaged LGC market prices published by AFMA over an extended period of 106 weeks for 2012 LGCs and 54 weeks for 2013 LGCs.

The Authority has used these averaged prices for LGCs, ORER's binding RPP for 2012 of 9.15% and ACIL's estimate of the RPP for 2013 of 9.97%[12], to arrive at a cost for complying with the LRET scheme of $4/MWh in 2012-13.

ACIL has provided a detailed explanation of its calculation of LRET costs in its Draft Report, along with information on LGC prices and assumptions underpinning the RPPs.

SRES Costs

For the 2011-12 BRCI, the Authority used a market-based approach to estimate SRES costs, relying on ORER's Clearing House price of $40 per STC as well as ORER's final STP published for 2011 and ACIL's STP estimate for 2012.

Approaches in Other Jurisdictions

IPART (NSW), ESCOSA (South Australia), the ICRC (Australian Capital Territory (ACT)) and OTTER (Tasmania) all adopted a market-based approach to estimate SRES costs based on ORER's Clearing House price of $40 per STC and ORER's binding and non-binding STPs for the relevant years.

Submissions

Submissions in response to the Authority's Issues Paper were broadly in favour of continuing to use a market-based approach, based on ORER's Clearing House price and ORER's binding and non-binding STPs.

However, following the release of the Authority's Draft Methodology Paper, QCOSS and Stanwell suggested that market prices for STCs should be used instead of ORER's Clearing House price given that there is an active market for STCs and the current market price is well below the Clearing House price. In contrast, AGL and TRUenergy supported the proposal to use ORER's binding and non-binding STPs.

The Authority's Position

While the current market price for STCs may be below the fixed Clearing House price of $40 per STC, as suggested by QCOSS and Stanwell, ACIL advised the Authority that there were difficulties with using market data because it would require forecasts of the proportion of STCs likely to be traded in 2012-13. Given that the STC market is for spot sales and information on the volume of STCs traded in the open market is not publicly available, ACIL recommended the Authority continue to use the Clearing House price.

The Authority accepts ACIL's recommendation and based its estimate of the SRES costs for 2012-13 on the STC Clearing House price of $40 per STC, ORER's binding STP for 2012 of 23.96% and non-binding STP for 2013 of 7.87%[13]. Based on this approach, the Authority has arrived at a cost of complying with the SRES of $6.37/MWh in 2012-13.

3.3.3 NEM Participation Fees and Ancillary Services Charges

NEM participation fees are levied on retailers by AEMO to cover the costs of operating the national energy market and ancillary services charges cover the costs of the services used by AEMO to manage power system safety, security and reliability.

[12] This information will be updated in the Final Determination based on updated information from ORER.
[13] This information will be updated in the Final Determination based on updated information from ORER.

As NEM participation fees and ancillary services charges are relatively stable from year to year, the Authority has previously used historical data to forecast these costs.

Approaches in Other Jurisdictions

Two general approaches to estimating NEM participation fees and ancillary services charges have been used recently in other jurisdictions. IPART, ESCOSA and OTTER used an approach similar to the Authority, whereby they forecast NEM participation fees and ancillary services charges based on historical prices. ICRC escalated historical NEM participation fees and ancillary services charges by the consumer price index (CPI).

In addition to its forecasts, OTTER provided a pass-through allowance in its 2010 Determination to account for any differences between the forecasts in its 2007 Determination and the actual data published by AEMO over the determination period.

Submissions

Submissions in response to both the Issues Paper and the Draft Methodology Paper generally supported the proposal by the Authority to continue using the approach to estimating NEM participation fees and ancillary services charges it had previously used under the BRCI.

The Authority's Position

As stakeholders have generally supported the Authority's approach to estimating NEM participation fees and ancillary services charges based on historical data, the Authority has continued with this approach for 2012-13.

Using AEMO's estimate of NEM fees, the Authority has estimated that total NEM fees will be $0.40/MWh in 2012-13.

Using AEMO's settlements data for ancillary services over the year to January 2011, the Authority has estimated that ancillary services charges will be $0.47/MWh in 2012-13.

3.3.4 Summary of Other Energy Costs for 2012-13

Table 3.5 shows ACIL's proposed other energy costs for 2012-13 which will be applied uniformly across all tariffs.

Table 3.5: Other Energy Costs for 2012-13

Cost Component	***$/MWh***	***c/kWh***
GEC	0.86	0.086
LRET	4.00	0.400
SRES	6.37	0.637
NEM fees	0.40	0.040
Ancillary services	0.47	0.047
Total	**12.10**	**1.210**

Source: ACIL Tasman, Estimated Energy Purchase Costs for 2012-13 Retail Tariffs, March 2012.

3.4 Total Energy Cost Allowances for 2012-13

Table 3.6 shows the total energy costs allowances for each settlement class and retail tariff for 2012-13.

Table 3.6: Total Energy Cost Allowances for 2012-13 by settlement class/tariff

Settlement class	*Retail Tariff*	*Wholesale energy allowance (c/kWh)*	*Other energy costs (c/kWh)*	*Total energy allowance (c/kWh)*
Energex NSLP	11, 12, 20, 22, 41	6.613	1.21	7.823
Energex Controlled Load 9000	31	4.499	1.21	5.709
Energex Controlled Load 9100	33	5.282	1.21	6.492
Ergon Energy NSLP	42, 43, 44, 53, 54, 55	5.957	1.21	7.167
Energex Unmetered Supply	71, 91	4.576	1.21	5.786

Source: ACIL Tasman, Estimated Energy Purchase Costs for 2012-13 Retail Tariffs, March 2012.

4. RETAIL COSTS

The final cost component to be determined relates to the cost of services provided by a retailer to its customers.

4.1 Introduction

In determining retail costs, the Authority must have regard to the general provisions of the Delegation, including:

(a) the actual costs of supplying electricity;

(b) the effect of its determination on competition;

(c) the Queensland Government's UTP; and

(d) the particular matters raised in the attachment to the Delegation.

In addition, in determining the retail cost component, there are some specific requirements provided in the Delegation, namely, that the Authority must consider the retail costs that would reasonably be incurred by an efficient, representative retailer (the characteristics of which are to be determined by the Authority).

The Authority is also required to determine an appropriate retail margin, giving consideration to any risks not compensated for elsewhere.

4.2 Representative Retailer

In its Issues Paper, the Authority discussed whether retail costs should be based on those incurred by an actual retailer or those likely to be incurred by a fictitious but representative retailer. However, the Delegation clearly requires that the retail costs to be determined are those for a representative retailer (rather than an actual retailer), the characteristics of which are to be determined by the Authority.

Under the previous BRCI approach to setting notified prices, the Electricity Act defined the representative retailer as an incumbent, stand-alone Queensland electricity retailer with a substantial and representative cross-section of customer types.

The BRCI required the Authority to calculate the expected <u>increase</u> in the costs of this representative retailer over the forthcoming year, with the increase in costs so determined then used to increase existing tariffs. The Authority did not adjust the underlying existing tariffs to reflect the actual level of costs incurred by the representative retailer.

The current Delegation requires the Authority to determine the appropriate <u>level</u> of costs for a representative retailer. As such, estimating the actual level of costs will have a direct impact on the resulting tariffs. This makes the determination of the representative retailer a more significant issue under the current arrangements than it was previously.

At the same time, the Delegation makes it clear that, in determining prices, it is important that the electricity market remain competitive, so that customers can benefit over the long term from the efficiencies and other benefits that competition can bring.

It is against this background that the definition of the representative retailer must be considered. The representative retailer is not meant to be an actual retailer nor is it meant to be some sort of average retailer. Rather, the representative retailer will have characteristics designed to achieve the desired market outcomes in terms of prices and competition.

4.2.1 Approaches in Other Jurisdictions

Unlike in Queensland, regulators in other jurisdictions are required to determine regulated retail electricity prices that must be offered by one, or a small number of, standard or default retailer(s) and tend to draw on cost information provided by that retailer(s). Nevertheless, in determining the appropriate level of costs to be recovered through prices, the regulators may also aim to reflect certain characteristics of a retailer that differ from those of the standard or default retailer(s).

In its final report on 2010-13 regulated retail prices in New South Wales (NSW), IPART aimed to establish the costs of a retailer that:

(a) is an incumbent retailer that has achieved economies of scale (has efficient costs);

(b) is a stand-alone retailer in NSW that is not vertically integrated with electricity distribution in NSW;

(c) serves retail customers, including small retail customers, in NSW and other jurisdictions across the NEM;

(d) can offer retail customers standard and negotiated customer supply contracts; and

(e) has an existing customer base to defend.

In its 2011-2014 pricing review in South Australia, ESCOSA decided that the regulated price should be set by reference to the small customer retail market in South Australia, rather than being based on the costs incurred specifically by the regulated retailer. It considered that adopting a new entrant retailer focus would ensure that electricity retailers are able to compete in the market and deliver the benefits of competition to customers.

In its 2010-2012 pricing review in the ACT, the ICRC estimated the efficient costs of an incumbent electricity retailer providing retail electricity services to a regulated customer segment.

In its 2010-2013 pricing review in Tasmania, OTTER aimed to determine the efficient costs of supplying non-contestable customers.

4.2.2 Submissions

In response to the Authority's Issues Paper, most retailers preferred that retail costs be determined for a new entrant, stand-alone retailer of small or moderate size providing retail electricity services in Queensland. Retailers generally were of the view that this would encourage competition and ensure new entrants were not at a disadvantage to incumbents.

However, some retailers suggested the representative retailer should be a vertically integrated retailer. For instance, in discussing the calculation of energy costs, Origin Energy argued that "an integrated retailer is more closely aligned to a representative retailer for which the QCA is seeking to establish efficient costs" but later preferred a stand-alone retailer as the basis for estimating retail costs.

Few consumer groups commented on the characteristics of the representative retailer. QCOSS and CANEGROWERS indicated a preference for the representative retailer to be an incumbent retailer that could take advantage of economies of scale. CANEGROWERS also preferred an integrated retailer that was engaged in a range of business activities and could take advantage of economies of scope.

Following release of the Authority's Draft Methodology Paper, retailers (except Ergon Energy) reiterated their view that a smaller new entrant was more appropriate. For example, TRUenergy suggested that the current level of competition might not be maintained if the Authority were to base costs on those of an incumbent retailer. While such a definition had been used in the BRCI, it was less significant under that approach because (as noted above) the BRCI was an index approach, whereas the current approach is a cost build-up.

Ergon Energy and non-retailers (including the CCIQ, Queensland Farmers' Federation, Growcom, QCOSS and Queensland Consumers Association) continued to prefer a definition based on a larger incumbent retailer.

4.2.3 The Authority's Position

Incumbent or New Entrant

Determining costs on the basis of a relatively small new entrant (as preferred by most retailers) could lead to higher costs than would result from the previous BRCI definition. Conversely, Ergon Energy and consumers indicated a preference for costs to be based on those for a large, incumbent retailer able to access economies of scale. This would lead to the basis for determining costs being more in line with those estimated in the past and lower than under the retailer preferred alternative.

In deciding on the characteristics of the representative retailer, the Authority first reviewed the current level of competition in the market. The Authority considered that, if the current level of competition were seen as deficient, a definition based on a new entrant might be preferred over one based on an incumbent.

The higher costs that would flow from adopting a new entrant perspective would result in higher notified prices (relative to adopting an incumbent perspective) and encourage new retailers to enter the market, thus promoting the level of competition but also imposing higher prices on customers. Conversely, if the level of competition in the market were seen as adequate, then a definition based on an incumbent retailer would result in (relatively) lower notified prices that do not unnecessarily penalise customers.

As discussed in Chapter 1, the retail electricity market in Queensland, in particular in SEQ, has developed considerably since the introduction of full retail competition in mid-2007. There are a large number of retailers servicing small and large customers and customer switching activity is strong.

As at 31 December 2011, there were 17 retailers[14] operating in Queensland – nine service both large and small customers, five service large customers only and three service small customers only.

While the Authority does not have access to information on the market offers available to business customers, there are currently 76 supply offers available to residential customers consisting of 27 for 'standard' electricity supply and 49 with green electricity options. These market offers provide customers (almost exclusively in SEQ) with a range of contractual terms and conditions combined with potential savings and other incentives.

The Authority is not aware of any market contracts generally available to residential customers in Ergon Energy's distribution area. While all retailers are licensed to operate across the State, each retailer will choose the locations in which it is prepared to make offers for supply and the types of customers it is seeking to attract.

[14] Some retailers hold more than one licence.

As shown in Table 4.1, some 43.6% of customers in Queensland and 66.1% of customers in SEQ were on market contracts as at 31 December 2011. This suggests that a large number of customers have embraced the option to choose a market contract that is better suited to their needs than their previous regulated tariff.

Table 4.1: Market and Non-Market Customers – as at 31 December 2011

Customer type	***Market customers[1]***		***Non-market customers***		***Total customers***		***% on market contracts[2]***	
	SEQ	***QLD***	***SEQ***	***QLD***	***SEQ***	***QLD***	***SEQ***	***QLD***
Small	876,128	879,060	455,920	1,148,571	1,332,048	2,027,631	65.8%	43.4%
Large[2]	12,457	14,637	530	7,129	12,987	21,766	95.9%	67.2%
All	888,585	893,697	456,450	1,155,700	1,345,035	2,049,397	66.1%	43.6%

Source: Information reported to the Authority under the Electricity Industry Code.
1. Assumes that any customer outside Energex's distribution area that is not serviced by Ergon Energy Queensland (retail) is on a market contract.
2. From 1 July 2012, all large non-residential customers in the Energex area will be on market contracts.

The rate of customer switching is often used to measure the level of activity in an electricity market. While not always the case, a high switching rate typically suggests that retailers are actively marketing in a region and that they are offering customers sufficient savings to incentivise them to switch retailers.

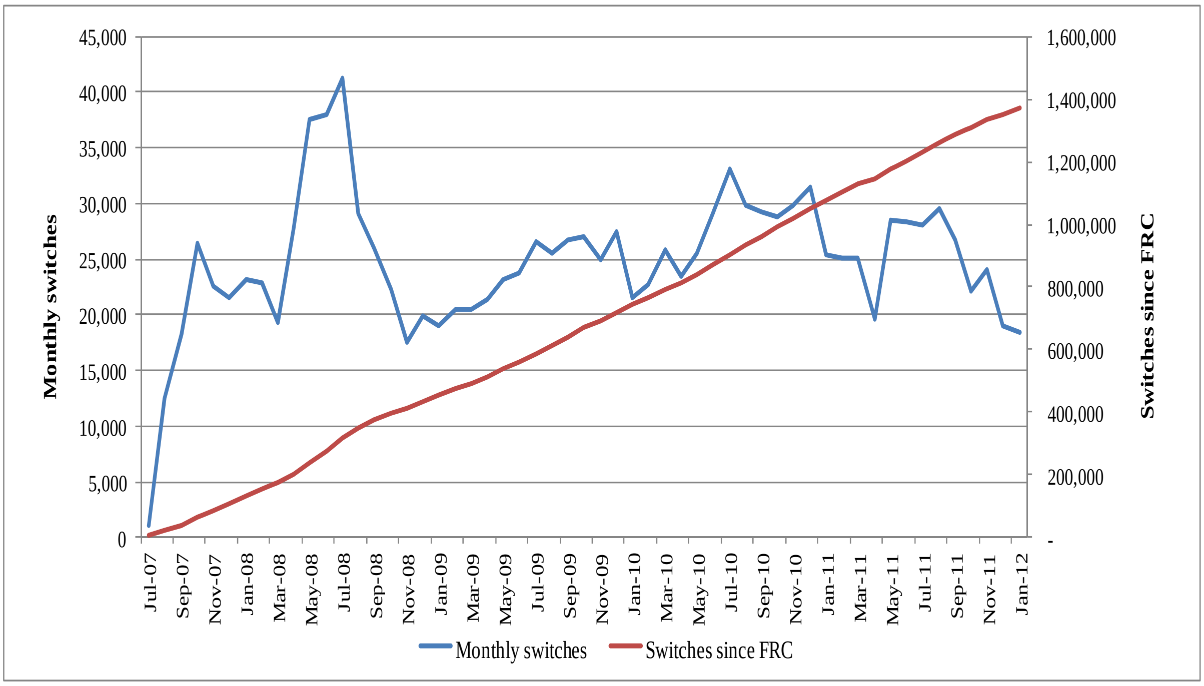
However, an abnormally active market might also suggest that potential profits in the market are high (perhaps due to the regulated retail tariffs being set too high) which would also encourage retailers to spend an unreasonable amount on marketing while offering customers large discounts.

Since FRC commenced in Queensland in 2007, the level of customer switching activity has been relatively high. Figure 4.1 shows monthly and total customer switches in Queensland since 2007. While there was considerable volatility in the switching rate over the initial 18 months of FRC, customer activity has typically stayed within the range of 20,000 to 30,000 customer switches per month in more recent years.

In comparison to other markets around the world, the level of customer switching activity in South East Queensland is particularly high, with the market being rated by one commentator as one of the most active retail electricity markets in the world[15].

[15] VaasaaETT. *World Energy Retail Market Rankings, 2010*, December 2010.

Figure 4.1: Customer Switching Activity, Queensland, Since FRC



Source: AEMO Retail Transfer Statistical Data (Code M57B)

The above analysis suggests the Queensland electricity market (and particularly the SEQ market) is attractive to retailers who are actively seeking market share with a wide range of market offers for customers. Given the over-riding impact of the Government's uniform tariff policy throughout the Ergon Energy area, there does not appear to be any reason to believe that the level of competition is deficient or that further steps need to be taken to attract new entrants. On this basis, the Authority considers that the definition of the representative retailer should be based on an incumbent retailer, not a new entrant.

Other Characteristics

Table 4.2 provides a snapshot of the characteristics of those retailers currently operating in the Queensland market. The size of the retailer, its degree of vertical integration, whether it is solely Queensland based and whether it markets products other than electricity, will all determine the economies of scope and scale that the representative retailer enjoys and the associated costs which must be recovered through prices.

Table 4.2: Characteristics of Active Retailers in Queensland

Retailer	*Small customers*	*Large customers*	*Market customers*	*Non-market customers*	*Retails electricity in other region*	*Retails gas in SEQ*	*Other horizontal integration*	*Vertically integrated*
Origin	**Y**	**Y**	**Y**	**Y**	**Y**	**Y**	**Y**	**Y**
AGL	**Y**	**Y**	**Y**	**Y**	**Y**	**Y**	**Y**	**Y**
Powerdirect	**Y**	**Y**	**Y**	**Y**	**Y**	**N**	**Y**	**Y**
TRUenergy	**Y**	**Y**	**Y**	**Y**	**Y**	**N**	**Y**	**Y**
Sanctuary	**Y**	**Y**	**Y**	**Y**	**Y**	**N**	**N**	**Y**
Lumo	**Y**	**Y**	**Y**	**N**	**Y**	**N**	**Y**	**Y**
APG	**Y**	**N**	**Y**	**N**	**Y**	**Y**	**Y**	**N**
Click	**Y**	**N**	**Y**	**N**	**Y**	**N**	**N**	**N**
Dodo Power and Gas	**Y**	**N**	**Y**	**N**	**Y**	**N**	**N**	**N**
Diamond Energy	**N**	**Y**	**Y**	**N**	**Y**	**N**	**N**	**Y**
QEnergy	**Y**	**Y**	**Y**	**N**	**N**	**N**	**N**	**N**
Momentum	**Y**	**Y**	**Y**	**N**	**Y**	**N**	**N**	**Y**
ERM	**N**	**Y**	**Y**	**N**	**Y**	**N**	**Y**	**Y**
Aurora	**N**	**Y**	**Y**	**N**	**Y**	**N**	**N**	**Y**
OzGen	**N**	**Y**	**Y**	**N**	**Y**	**N**	**N**	**Y**
Stanwell	**N**	**Y**	**Y**	**N**	**N**	**N**	**N**	**Y**
Ergon Energy Queensland	**Y**	**Y**	**N**	**Y**	**N**	**N**	**Y**	**Y**

As Table 4.2 indicates, active electricity retailers in Queensland are not homogeneous in nature but fall into three broad categories, as follows:

(a) Ergon Energy Queensland, which supplies only non-market customers and operates solely within the Ergon Energy distribution area;

(b) specialised retailers who supply only large market customers, with a number being predominantly generators who are registered as retailers to supply (often) very large customers; and

(c) retailers who supply large and small customers.

Within category (c), retailers generally:

(a) retail electricity in Queensland (predominantly in the Energex distribution area of SEQ) as stand-alone electricity retailers and not also as retailers of gas (although the two largest retailers of electricity also retail gas);

(b) serve small and large retail customers in Queensland and other jurisdictions across the NEM.

While some retailers pursue customers only in a particular market niche, most operating in Queensland supply a mix of small and large customers. There are notified prices for all tariff categories despite large customers (those consuming above 100 MWh per annum) in Energex's network being denied access to notified prices from 1 July 2012.

While not all retailers have non-market customers, small customers who accept a market contract may revert to a non-market contract with their current supplier at the notified price on the expiry of their market contract, or as otherwise provided for in their market contract; and

(c) are vertically integrated, however, the nature and extent of the vertical integration varies considerably. AGL and Origin Energy are the only retailers with significant customer bases that operate large-scale generation assets connected to the NEM in Queensland. All other retailers with generation assets have either relatively small customer bases in Queensland or generation assets in other states, or both. In general, new entrants are not vertically integrated.

In addition, the cost structure of the representative retailer will be affected by the size of its customer base. A large incumbent retailer will already have an established customer base while a smaller retailer may not be able to access the same economies of scale. However, there is also some evidence to suggest that reasonable economies of scale may be achieved with a relatively small customer base[16]. Smaller retailers may also gain the benefits of economies of scale that would naturally flow to a retailer with a larger customer base by outsourcing many back office functions to a third party. On this basis, size may not be as important an issue as it might otherwise appear, nevertheless, the Authority will define the representative retailer as having sufficient size to access economies of scale.

Summary

In arriving at its definition of the representative retailer, the Authority has recognised:

(a) the maturity and competitiveness of the Queensland market which supports a mix of retailers from small new entrants to large incumbents; and

(b) the importance of maintaining a competitive market in the future by not deterring the entry of new retailers which can drive efficiency in the market and potentially lead to lower prices and a wider range of services in the longer term.

While notified prices apply only to non-market customers, the reality is that these set the basis for determining prices for all customers, both market and non-market. In addition, most customers (probably all small customers) throughout the Ergon Energy distribution area will pay the notified prices set by the Authority as there is little if any competition in that part of the State meaning that customers are unable to choose an alternate supplier.

In practice, the Authority's task is a matter of balancing the desire by some stakeholders for higher regulated prices which will promote more activity in the market against the desire by others for lower electricity bills.

The Authority's task is to set prices that will sustain an appropriate level of competition in the market in order to place downward pressure on prices but not set prices so high as to deny customers the benefits that come from a competitive market in terms of greater efficiency and lower prices than might otherwise prevail.

Based on the above considerations, the Authority considers that the representative retailer is one that:

[16] Frontier Economics, *Mass Market New Entrant Retail Costs and Retail Margin, Prepared for the Independent Pricing and Regulatory Tribunal*, March 2007.

(a) is an incumbent retailer of sufficient size to have achieved economies of scale;

(b) serves small and large retail customers in Queensland and other jurisdictions across the NEM;

(c) has a mix of market and non-market customers;

(d) retails electricity on a stand-alone basis; and

(e) is not vertically integrated with an electricity generator.

4.3 Retail Operating Costs

Retail operating costs (ROC) relate to the costs of the services provided by an electricity retailer to its customers and typically include customer administration (including call centres), corporate overheads, billing and revenue collection, IT systems, regulatory compliance, and customer acquisition and retention costs (CARC) which also includes costs associated with marketing, advertising and sales overheads.

As noted at the start of this chapter, it is the ROC that would reasonably be incurred by an efficient, representative retailer that the Authority must consider.

4.3.1 Approach to Estimating ROC

In its Issues Paper, the Authority identified that there are two generally accepted approaches to estimating ROC. A bottom-up approach, which requires detailed information on each cost component, or a benchmarking approach, which relies on publicly available information and is therefore less data intensive. The two approaches can also be used together, with benchmarking used to assess the reasonableness of costs estimated under a bottom-up approach.

Under the BRCI, the Authority initially estimated ROC in 2006-07 by benchmarking costs to those allowed in other jurisdictions and subsequently escalating this benchmark each year to account for wages growth and price inflation over the intervening period.

Prior to the 2011-12 BRCI Decision, the Authority also calculated a separate cost item to cover CARC based on expected rates of customer churn (except for the first BRCI where a loss of scale approach was used). However, in its 2011-12 BRCI Decision, the Authority considered that, given the maturity of the Queensland market (particularly the SEQ market), it was no longer appropriate to calculate a separate cost for CARC but that these costs should be treated in the same manner as all other retail costs. Consequently, the Authority arrived at an overall estimate of ROC in 2011-12 which included an allowance for CARC.

The ROC estimate for the 2011-12 BRCI also included an additional cost associated with the regulatory fees levied by the Authority.

Approaches in Other Jurisdictions

The most recent approaches adopted by regulators in other jurisdictions are summarised below. Key differences in the approaches adopted in other jurisdictions relate to the treatment of CARC and the fact that other regulators have to estimate costs for an actual retailer.

IPART (NSW) estimated ROC using a bottom-up approach based on cost information provided by the three regulated retailers. It then benchmarked this estimate against its past determinations, regulatory decisions in other jurisdictions and cost information disclosed by publicly listed retailers.

IPART was required by its terms of reference to include an explicit allowance for CARC. IPART estimated CARC separately and for its 2010 determination used an approach based on customer churn (similar to the Authority's approach prior to the 2011-12 BRCI).

ESCOSA (South Australia) adopted a similar approach to IPART in determining ROC in the initial year – an assessment of the regulated retailer's actual costs and benchmarking against other regulatory decisions, combined with benchmarking against market contracts in subsequent years. That is, ESCOSA determined a cost-reflective price for the start of the price path which was adjusted in subsequent years in line with movements in market contract prices (subject to prices sitting within a floor and ceiling).

ESCOSA included an implicit allowance for CARC in the ROC. ESCOSA justified accepting the regulated retailer's proposed ROC allowance (including CARC) on the basis that it was consistent with the ROC allowance recommended by its consultant, LECG (now Sapere Research Group), which had estimated CARC using a similar method to that adopted by IPART.

The ICRC (ACT) established an initial ROC estimate in 2003 on the basis of information provided by the regulated retailer and benchmarking. This estimate was then escalated in subsequent years according to movements in the CPI.

The ICRC did not include any allowance for CARC. The ICRC considered that the potential benefits of enhancing competition did not outweigh the potential negative impacts, including higher prices in the short term.

OTTER (Tasmania) benchmarked the regulated retailer's ROC against other jurisdictions. OTTER made no allowance for CARC as it considered CARC was not a valid cost element when dealing solely with customers who are not contestable.

Submissions

In response to the Authority's Issues Paper, retailers suggested different approaches to estimating ROC, such as:

(a) Origin Energy preferred benchmarking but noted that it can be difficult to compare decisions due to different methodologies and parameters used to approve costs. It therefore suggested that the current allowance should be retained and escalated;

(b) QEnergy supported the approach used to date, although it was not clear whether it was proposing that a new benchmark be established and escalated annually or that the current allowance should be retained and escalated;

(c) AGL supported benchmarking but with an allowance for Queensland specific costs and the incremental costs of a stand-alone new entrant retailer;

(d) Ergon Energy suggested that IPART's cost estimate should be adopted (with some Queensland specific adjustments) and that a high level assessment of this estimate could be undertaken against aggregated cost data provided by retailers; and

(e) APG, TRUenergy and Alinta Energy did not propose a specific approach, although TRUenergy emphasised the importance of accounting for Queensland specific costs and regulatory obligations, while Alinta Energy was of the view that the current allowance was reasonable, albeit conservative.

Consumer groups did not make specific comments on the appropriate approach, although CCIQ considered that the approach adopted should include mechanisms to reflect performance and productivity outcomes.

In relation to the treatment of CARC, QCOSS and CANEGROWERS were of the view that there was no justification for including an allowance for CARC while retailers supported the inclusion of a CARC allowance, but had different views as to how it should be calculated, including:

(a) TRUenergy and AGL considered that it should be calculated by reference to churn rates;

(b) Origin Energy suggested that it should be calculated based on the costs incurred by a new entrant retailer and that it must cover all costs a retailer incurs in acquiring, retaining and transferring a customer. However, once calculated, Origin Energy supported the escalation of those costs on the same basis as other ROC; and

(c) QEnergy supported the approach used to date, presumably including treating CARC in the same manner as other retail costs.

The Authority's Position

In order to undertake a bottom-up analysis of retail costs, the Authority would need to obtain detailed cost information from retailers. While Origin Energy, AGL and APG all indicated they would be willing to provide cost information, the Authority considers that there are a number of problems with this approach.

Firstly, there is no standard or default retailer(s) in Queensland as all retailers must offer regulated or notified prices. Under the Delegation, the Authority is required to consider the costs of an efficient, representative retailer, so it would need to either:

(a) determine which retailer or retailers best met the definition of the representative retailer and obtain cost information from those retailer(s); or

(b) ask retailers to provide an estimate of the costs likely to be incurred by the representative retailer, rather than providing cost information relating directly to their own business.

Even if the Authority were able to obtain reliable cost information, determining the efficiency and reasonableness of those costs would be difficult. Other sources of information on the disaggregated costs of retailers are not available to inform the Authority's assessment because retailers have not provided the Authority with ROC information in the past and, in other jurisdictions, if retailers provide disaggregated cost information to the regulator this tends to be on a confidential basis. Origin Energy also noted that the process of obtaining information would be data intensive and that it had been a contentious issue in other jurisdictions given the different structures and activities of the various retailers. Ergon Energy had similar concerns, noting that information may be classified quite differently between retailers, making comparisons difficult.

While the Authority could assess cost estimates using a high level benchmarking analysis, a potential problem would arise if there was a large discrepancy between the results of the benchmarking analysis and retailers' proposed costs or even between retailers themselves. This would likely require the Authority to choose one approach (or cost estimate) over the others and there may be little basis for doing so.

Given these difficulties, the Authority has decided not to pursue a bottom-up evaluation of ROC. Instead, the Authority will use its ROC allowance from the last BRCI (2011-12) as a starting point and benchmark that allowance against those recently accepted in other jurisdictions in order to test its reasonableness. While the Authority notes that benchmarking has its drawbacks, it does not consider that an alternative approach would necessarily produce results that are any more robust or defensible.

Some retailers had suggested that Queensland specific costs and regulatory obligations need to be taken into account. Where reliable information on the individual components of ROC is readily available, the Authority will consider adjusting its estimate to include those costs. This approach is consistent with the Authority's approach under the BRCI, where it included a new cost item within ROC in the 2011-12 BRCI decision to recognise the imposition by the Authority of regulatory fees.

Given the concerns of some (non-retailer) stakeholders regarding the treatment of CARC, the Authority considered whether it is appropriate to include an allowance for CARC. Under the Delegation, the Authority is required to consider the ROC that would reasonably be incurred by an efficient, representative retailer and, as discussed above, the Authority has defined the representative retailer as one that supplies customers on both market and non-market contracts. The Authority is also required to consider the impact on competition in the Queensland retail electricity market of its determination, consistent with the Government's policy objective that consumers, wherever possible, have the opportunity to benefit from competition and efficiency in the marketplace.

Some amount of CARC is a reasonable and real cost incurred by retailers participating in a competitive market and supplying both market and non-market customers. Not recognising a legitimately incurred cost may have a detrimental impact on competition by reducing the incentive for retailers to actively participate in the market. In line with these requirements, the Authority considers that it is appropriate for CARC to continue to be reflected in the ROC.

Following release of the Draft Methodology Paper, Alinta Energy, AGL, Origin Energy, CCIQ, Ergon Energy and QCOSS supported the proposed benchmarking approach although, as noted previously, retailers would have preferred costs be based on a smaller new entrant representative retailer. While the Queensland Farmers' Federation preferred obtaining disaggregated cost information from retailers, it supported benchmarking as the next best option.

Retailers and CCIQ supported the continued inclusion of an allowance for CARC while Queensland Farmers' Federation, QCOSS and Queensland Consumers Association did not but, if the Authority opted to include an allowance for CARC, the Queensland Consumers Association preferred that it be calculated separately. AGL and Origin Energy supported the Authority's proposed approach which would maintain the current CARC allowance in real terms.

CCIQ suggested that a low and declining allowance would be consistent with a retailer maintaining high customer satisfaction and efficiency standards and a declining allowance would incentivise retailers to improve their performance. The Queensland Consumers Association was also concerned that the present allowance was based on an assumption that most customers are acquired through expensive door-to-door marketing, which does not provide an incentive for retailers to pursue alternative and less intrusive marketing methods.

The Authority considered these and other arguments regarding the treatment of CARC in arriving at its 2011-12 BRCI Decision. Having established an acceptable approach in its 2011-12 BRCI Decision, and arrived at a suitable estimate of a combined ROC, the Authority is not persuaded to change from that approach.

4.3.2 Implementing the Benchmarking Approach

Setting a Benchmark ROC Allowance for Residential and Other Small Customers

In undertaking the benchmarking analysis, a key point to note is that the Authority must determine regulated retail electricity prices for all small customers and large customers (those consuming more than 100 MWh per annum), whereas regulators in other jurisdictions are required to set prices for small customers only, to be charged by specific retailers.

In other jurisdictions, customers are only eligible to be supplied under a regulated retail tariff if their annual consumption is below 160 MWh in NSW and South Australia, 100 MWh in ACT or 50 MWh in Tasmania[17]. Therefore, the benchmarks from these jurisdictions are most relevant in providing information on the costs of supplying relatively small customers.

In undertaking the benchmarking analysis, the Authority acknowledges the concerns of AGL and Origin Energy that the benchmarking exercise should be undertaken on a consistent basis and that differences in regulatory and market frameworks need to be taken into account. While QCOSS cautioned that making substantial adjustments to the benchmarks from other jurisdictions requires an understanding of the individual components of the benchmarks, the Authority considers that it is appropriate to make some adjustments to account for jurisdictional differences where reliable information on the individual cost components exists.

As noted previously, a key difference between jurisdictions is the treatment of, and basis for calculating, CARC. As it has not been possible to readily compare the costs attaching to CARC between jurisdictions, the Authority has based its benchmarking solely on comparable ROC allowances and, as in 2011-12, will maintain the current, perhaps generous, CARC component going forward.

Recent Regulatory Decisions

Table 4.3 compares the Queensland ROC allowance under the 2011-12 BRCI approach with allowances recently determined by regulators in other NEM jurisdictions. In order to improve comparability between jurisdictions, the allowances have been adjusted to exclude CARC (if it has been included) and all allowances are presented in 2011-12 dollars. Some other minor adjustments have also been made as noted below.

[17] Customers consuming between 50 MWh and 150 MWh per annum were eligible until July 2011. After that date, these customers became contestable and were unable to access regulated tariffs.

Table 4.3: Current ROC Allowances (per customer)

	ROC	*CARC*	*ROC (excl CARC)*	*ROC (excl CARC)*[1] *$2011-12*	*Comments*
Queensland (2011-12 allowance)	$130.74 ($2011-12)	$41.91 ($2011-12)	$88.83 ($2011-12)	$88.83	Excludes regulatory fees of $1.16. Retailers not allowed to charge late payment fee.
NSW[2] (IPART)	$112.10-$116.00 ($2009-10)	$36.80 ($2009-10)	$75.30-$79.20 ($2009-10)	$79.65-$83.78	Includes $2.30 cost associated with late payments (recovered through separate late payment fee).
South Australia (ESCOSA)	$115 ($2010-11)	$38.00[3] ($2010-11)	$77.00 ($2010-11)	$79.54[4]	Excludes allowance for Residential Energy Efficiency Scheme (REES) costs. Retailers allowed to charge separate late payment fee.
ACT (ICRC)	$104.90 ($2010-11)	Not included	$104.90 ($2010-11)	$107.89	Includes cost of meter reading (not a ROC in Qld). Includes some sales and marketing costs.
Tasmania (OTTER)	$94 ($2010-11)	Not included	$94 ($2010-11)	$96.49	Set to recover costs of supplying non-contestable customers, so no allowance for impact of FRC.

1. *Allowances have been escalated to $2011-12 in accordance with each regulator's determination (except for ESCOSA allowance – see below).*
2. *A range is presented because ROC increases in each year of the determination period as a result of the need to recover fixed costs from a declining customer base. IPART, Review of regulated retail tariffs and charges for electricity 2010-2013, Final Report, March 2010, pp. 120-121.*
3. *CARC allowance estimated from regulatory decision as not separately itemised. See: ESCOSA, 2010 Review of Retail Electricity Standing Contract Price Path, Final Inquiry Report and Final Price Determination, December 2010, p. A-86 & A-89; and Sapere Research Group, 2011 Review of the South Australia gas standing contract retail operating cost and retail operating margin: Report to the Essential Services Commission of South Australia, April 2011, p. 45.*
4. *The regulated price is adjusted in line with movements in market contract prices (subject to a floor and ceiling price), so it is not possible to isolate the change in the underlying ROC component. Therefore, the allowance has been escalated by the CPI escalator used to establish the floor and ceiling price in each year.*

The Authority considers that the IPART and ESCOSA determinations are more comparable with the Authority's task than are allowances determined by the ICRC and OTTER. The allowances determined by IPART and ESCOSA were based on the costs of large retailers that are likely to have achieved economies of scale and this is consistent with the Authority's representative retailer definition.

While the allowances determined by ICRC and OTTER are higher than the Authority's 2011-12 allowance, the retailers in those jurisdictions supply small customer bases and are unlikely to be operating at scale[18]. The ICRC allowance also included the cost of meter reading (which is not a ROC item in Queensland) and some sales and marketing costs (which could not be separately identified), while OTTER set ROC to recover the costs of supplying non-contestable customers and excluded costs associated with the introduction of FRC (because it has not been introduced there yet).

Ergon Energy argued that the IPART benchmark was the most relevant because it relied on the cost information of multiple retailers, but also noted that it may be appropriate to adjust the benchmark to account for Queensland specific costs. Origin Energy, on the other hand, argued against placing too much reliance on the IPART benchmark, because it was not consistent with the costs of operating in a contestable market either as an incumbent or new entrant. However, it is not clear which benchmarks Origin Energy considered to be more comparable, for example, it did not argue that ESCOSA's allowance was too low even though it is similar to that determined by IPART.

Origin Energy also argued that there were Queensland specific adjustments that needed to be taken into account, including:

(a) higher licence fees in Queensland than other jurisdictions;

(b) the lack of a late payment fee or credit card surcharge; and

(c) the Authority's regulatory fees.

While Origin Energy provided no information on the extent of difference in licence fees, the Authority understands that licensing will be the responsibility of the AER from 1 July 2012 and this will, presumably, bring a degree of uniformity to these charges.

While the Authority understands that regulated retailers in NSW and South Australia are not able to charge customers for paying by credit card, the Authority acknowledges that, unlike Queensland retailers, retailers in NSW and South Australia are allowed to charge late payment fees. However, based on the information provided in IPART's determination, the ROC allowance has already been adjusted upwards (by $2.30 per customer) to include the costs associated with late payments. This may also partially explain why the ESCOSA allowance is lower than that of IPART.

The Authority has previously agreed that the regulatory fees that the Authority imposes on retailers would be recognised in setting retail costs.

Publicly Reported Costs

The Authority also considered publicly available information on ROC. AGL cautioned against using its reported cost data as it claimed this did not represent the total costs of operating its retail business. While the Authority reviewed the most recently available cost information reported by publicly listed Queensland retailers, it has decided against relying on this information because:

(a) there were relatively large differences in reported costs between retailers;

(b) it was difficult to determine which costs were included or excluded; and

[18] ICRC, *Final Decision, Retail Prices for Non-contestable Electricity Customers 2010-2012*, June 2010, pp. 39-40; OTTER, *Investigation of Maximum Prices for Declared Retail Electricity Services on Mainland Tasmania, Draft Report*, August 2010, p. 71; and OTTER, *Investigation of Maximum Prices for Declared Retail Electricity Services on Mainland Tasmania, Final Report*, October 2010, p. 77.

(c) actual costs may not reflect efficient costs.

The Authority's Position

While AGL, Origin Energy and Alinta Energy indicated that they considered the 2011-12 ROC allowance in Queensland to be reasonable, the Authority's benchmarking analysis suggests that the current allowance is most likely too high to reflect the efficient costs of supplying small customers. In particular, the IPART and ESCOSA allowances (which the Authority considers to be the most comparable) are both lower than the Authority's allowance.

Therefore, the Authority considers that a ROC allowance of $83.78 per small customer is appropriate. This is consistent with the top of the IPART range of $83.78 which, unlike the ESCOSA allowance, includes an allowance for the costs associated with late payments and appears to be the most appropriate benchmark ROC allowance per small customer. IPART's representative retailer definition is also comparable with that of the Authority, being based on a larger incumbent that has achieved economies of scale rather than a smaller new entrant.

In total, this would make the 2011-12 base ROC allowance $125.69 per customer (including CARC of $41.91 per customer). To arrive at its estimate of ROC for 2012-13, this base amount will be inflated as discussed below.

Setting a Benchmark ROC Allowance for Large Customers

In addition to determining regulated retail prices for small customers, the Authority is required to determine regulated prices for large customers consuming more than 100 MWh per annum.

There is limited publicly available information upon which to determine an appropriate ROC allowance for large customers because, as noted above, regulators in other jurisdictions only set prices for smaller customers.

In a 2009 report for the Western Australian Office of Energy, Frontier Economics reviewed confidential cost data provided by the regulated retailer (Synergy) which suggested that the costs of supplying medium and large business customers was significantly higher than the costs of supplying small residential and business customers[19]. Frontier Economics suggested that this reflected more substantial marketing and account management costs and the additional cost of pricing large customer loads.

Frontier Economics recommended that different ROC allowances should apply depending on the size of the customer as follows:

(a) for those tariffs where the majority of customers were consuming below the contestability threshold of 50 MWh per annum - $75 per customer (which excludes CARC as ROC was being estimated in this case for the supply of non-contestable small customers); and

(b) where the majority of customers were consuming above the contestability threshold:

    (i) $700 per customer for those tariffs where customers consumed around 200 to 400 MWh per annum on average; and

    (ii) $2000 per customer for those tariffs where customers consumed around 1.7 to 4 GWh per annum on average.

[19] Frontier Economics, *Electricity Retail Market Review – Electricity Tariffs: Final Recommendations Prepared for the Western Australian Office of Energy*, January 2009, pp. 68-69.

In 2011-12 prices, this would equate to $771 per customer where customers were consuming around 200 to 400 MWh per annum and $2,204 per customer at the higher level of consumption. Both of these allowances include CARC.

The Western Australian Office of Energy recommended price increases (including these ROC estimates for large customers) in order to make prices cost-reflective from 2009-10, but the Western Australian Government decided to approve lower price increases in recognition of the impact of the financial downturn and the financial pressure on consumers. The Economic Regulation Authority (ERA) in Western Australia has recently been asked to undertake a further review of Synergy's costs and provide recommendations regarding cost-reflective tariffs.

While the above estimates suggest there is a significant difference in the retail costs of servicing larger customers, comments in submissions provided mixed views as to whether any cost differences exist. For example, AGL suggested that there may be some differences in the costs of supplying residential, business and rural customers, but QEnergy considered that costs per customer were similar, regardless of the size of the customer.

Were the Authority to apply the above estimates for large customers, given that the underlying network tariffs for large customers are designed for customers consuming above or below 4 GWh per annum, the appropriate benchmark allowances would be:

(a) $771 for customers consuming between 100 MWh and 4 GWh per annum; and

(b) $2,204 for customers consuming more than 4 GWh per annum.

The ROC allowances of $125.69 per small customer, $771 per large customer and $2,204 per very large customer would roughly account for 11% of a typical residential customer’s bill, 1% of a typical large customer’s bill and less than 1% of a typical very large customer’s bill.

The Authority's Position

The Authority acknowledges that there is limited evidence upon which to determine the appropriate amount of ROC to allow for large customers. As noted, there were also mixed views in submissions on this issue. However, it does seem reasonable that retailers may have to incur higher costs to target larger customers as they are less numerous and hence low cost blanket marketing would not be appropriate. They are also likely to require more time and effort to analyse their energy needs and construct appropriate offers. It would also seem reasonable that the larger the customer the more corporate time and effort may be required to maintain them and manage their accounts.

Therefore, the Authority is of the view that a higher amount of ROC is appropriate for large and very large customers.

In the absence of any better measure or benchmark of what this amount might be, the Authority has, for the purposes of this Draft Determination, decided to include a 2011-12 base ROC allowance of $771 per large customer (those consuming between 100 MWh and 4 GWh per annum) and $2,204 per very large customer (those consuming more than 4 GWh per annum) customer. To arrive at its estimate of ROC for 2012-13, this base amount will be inflated as discussed below.

Escalating ROC to 2012-13 Values

As the benchmark ROC allowances accepted above are in 2011-12 prices, it is necessary to reflect any change in costs between 2011-12 and 2012-13 in order to arrive at an allowance for 2012-13.

Under the BRCI, the Authority escalated retail costs from year to year using a 60/40 weighting of the change in the wage price index (WPI) and consumer price index (CPI) to reflect that labour costs account for approximately 60% of ROC.

However, the approach most commonly used in other jurisdictions to escalate costs from year to year within multi-year regulatory periods is to base increases solely on the change in the CPI.

While labour costs may be substantial, escalating those costs by WPI does not take into account any improvements in productivity (which is difficult to measure). It is also not clear that wages have been increasing at a higher rate than CPI in recent times. For example, AGL reported that labour rates increased in line with inflation in the 2010-11 financial year[20].

Due to the difficulties of accounting for cost increases net of efficiency improvements, it would be simpler and probably just as robust to escalate ROC just by the CPI.

For the purposes of this Draft Determination, the Authority decided to escalate ROC using only the change in the CPI. The Authority has drawn its CPI estimate for the 12 months to 30 June 2013 (3.25%) from the Reserve Bank of Australia (RBA) Statement on Monetary Policy of February 2012. This estimate will be updated for the Final Determination. This is the same source the Authority previously used in its BRCI Decisions.

Regulatory Fees

In its 2011-12 BRCI decision, the Authority included an amount ($2.358 million or $1.16 per customer) in ROC to reflect the imposition of regulatory fees by the Authority.

The aggregate of fees to be paid to the Authority by electricity retailers in Queensland is calculated by the Authority based on its estimate of the annualised actual cost of performing its functions over the five-year period from 1 July 2010 to 30 June 2015. However, adjustments to this estimate may be made during the period to ensure that fees are not significantly higher or lower than the Authority's actual costs. The total cost to be paid by retailers in 2012-13 is $2.494 million.

This total cost is recovered from retailers according to their market share. Based on the most recently available data on customer numbers of 2,049,397 (as at 31 December 2011), this translates into a per customer cost of $1.22 for 2012-13.

This estimate will be updated in the Final Determination based on March quarter customer number data and any known update of likely fees for 2012-13.

Accounting for New Costs in 2012-13

The Authority has previously indicated that, where reliable information on the individual components of ROC is readily available, it will consider adjusting its estimate to include those particular costs.

Origin Energy suggested that adjustments should be made to ROC to account for new costs likely to be incurred in 2012-13 that would not have been accounted for when setting the 2011-12 benchmark. These included:

(a) the implementation of the NECF from July 2012, which will require major system and process improvements;

[20] AGL Energy Limited, *Preliminary Final Report, Results for Announcement to the Market for the Year Ended 30 June 2011, Appendix 4E*, 25 August 2011, p. 11.

(b) additional administration and reporting obligations associated with the introduction of the carbon tax; and

(c) the impact of the current tariff reform.

To a greater or lesser degree, there will always be changes to retailers' operating and regulatory environments, which could increase or decrease retailers' costs. For instance, retailers may incur additional costs associated with regulatory changes in 2012-13, but compliance costs are likely to decrease with the centralisation of retail electricity regulation under the NECF. Therefore, it is not clear what the overall effect of these changes will be.

While there may be some additional costs associated with each of these events in 2012-13, they are not likely to be on-going costs and, to the extent that any increase was made to ROC in 2012-13 (if it could be determined what an appropriate amount might be), this would simply be offset by a reduction in ROC in 2013-14 when these one-off costs were removed.

The Authority is therefore not inclined to make any further specific adjustments to its ROC estimate.

The Authority's Draft Determination

For the purposes of the Draft Determination, the Authority will escalate ROC (except for regulatory fees which will be separately estimated for 2012-13) by the CPI and, other than the latest estimate of regulatory fees, has included no new costs in 2012-13 that need to be separately accounted for.

The Authority proposes to set three different ROC allowances to reflect the costs of supplying customers of different sizes, as set out in Table 4.4 below.

Table 4.4: 2012-13 ROC ($ per customer)

	2011-12 BRCI	*Revised 2011-12 Base*	*2012-13 Inflated*[1]
Residential and other small customers consuming up to 100 MWh/yr:[2]			
Benchmark ROC	88.83	83.78	86.50
+ CARC	41.91	41.91	43.27
+ Regulatory fees	1.16	1.18[3]	1.22
Total ROC	**131.90**[4]	**126.87**	**130.99**
Large customers (consuming between 100 MWh and 4 GWh/yr):			
Benchmark ROC (incl CARC)	130.74	771.50	796.57
+ Regulatory fees	1.16	1.18[3]	1.22
Total ROC	**131.90**[4]	**772.68**	**797.79**
Large customers (consuming more than 4 GWh/yr):			
Benchmark ROC (incl CARC)	130.74	2204.28	2275.92
+ Regulatory fees	1.16	1.18[3]	1.22
Total ROC	**131.90**[4]	**2,205.46**	**2,277.14**

1. *CPI escalation factor is 3.25%.*
2. *While some residential customers may consume more than 100 MWh per year, the small customer ROC has been applied to all residential customers.*
3. *Estimated directly for 2012-13, but included in $2011-12 for comparison purposes.*
4. *Under the BRCI, the same ROC applied to all customers.*

4.3.3 Fixed and Variable Components

In its Issues Paper and the Draft Methodology Paper, the Authority discussed the allocation of ROC to individual tariffs and whether this should be as a fixed or variable charge or some combination of both.

In theory, cost reflectivity is achieved when the costs of supply are applied to each retail tariff on the basis of the driver or cause of those costs. Such an approach should lead to more efficient use of electricity because customers would pay for the costs they cause an efficient retailer to incur, no more and no less. Therefore, as a general rule, the mix of prices for each tariff between fixed and variable components should reflect the manner in which the underlying costs are incurred. Fixed costs are best recovered as fixed charges and costs that vary with consumption are best recovered as variable charges.

Approaches in Other Jurisdictions

In other jurisdictions, regulated retailers tend to have the flexibility to set their own prices subject to a weighted average price cap (WAPC) determined by the regulator. Setting a WAPC is a more light-handed form of regulation than determining individual tariffs and prices and, therefore, many of the issues that the Authority faces in applying costs to retail tariffs do not arise in other jurisdictions. As noted by IPART in its final report on 2010-13 regulated retail prices:

> *Under a WAPC approach, IPART determines the maximum average percentage by which each [regulated retailer] can increase its regulated tariffs (weighted by the relevant quantity) in each year of the determination period. The [regulated retailer] can then adjust the level and structure of individual regulated tariffs as it sees fit, provided that on average, these tariffs do not increase by more than the maximum percentage.*[21]

In setting the WAPC, IPART split energy and retail costs into fixed components (costs that do not vary with electricity consumption) and variable components (costs that do vary with the level of consumption) and then weighted the fixed components of prices by customer numbers and the variable components by estimated electricity consumption. In undertaking this task, IPART assumed that:[22]

(a) energy costs were fully variable;

(b) ROC (excluding CARC) was 75% fixed and 25% variable;

(c) CARC was fully fixed; and

(d) the retail margin was fully variable.

Submissions

In response to the Authority's Issues Paper, retailers were generally of the view that most (if not all) ROC was driven by customer numbers rather than electricity consumption and that it would be appropriate to apply ROC either fully (AGL and QEnergy) or largely (Origin Energy and Ergon Energy) to the fixed component of retail tariffs. In suggesting that a small proportion of costs could be applied to the variable component of retail tariffs, Origin Energy and Ergon Energy suggested that the approach adopted by IPART (which treated 75% of ROC and 100% of CARC as fixed costs and 25% of ROC as variable costs) was a sound basis to follow.

The Authority's Position

There are two possible options for applying ROC to each retail tariff:

(a) estimating the total ROC allowance applicable to each retail tariff group by multiplying the relevant (small, large and very large) per customer allowance by the total number of customers in that group and applying those costs as partly fixed and partly variable, as IPART did, as follows:

    (i) 75% of costs (and 100% of CARC) equally to the fixed component of each retail tariff within the retail tariff group; and

    (ii) 25% of costs equally to the variable or consumption component of each retail tariff within the retail tariff group; or

(b) applying the relevant per customer ROC allowance directly to the fixed component of the relevant retail tariff.

[21] IPART, *Review of Regulated Retail Tariffs and Charges for Electricity 2010-2013, Final Report*, March 2010, p.61.
[22] Ibid., p.141, p.220.

In the Draft Methodology Paper, the Authority proposed to adopt option (a) because it was consistent with the approach chosen by IPART and supported by Origin Energy and Ergon Energy. QCOSS and CCIQ also endorsed this approach.

However, after further consideration, the Authority believes that it may have misinterpreted the IPART approach. While IPART treated 25% of ROC as variable with respect to electricity consumption, it appeared to have found that the variable portion of ROC is driven by customer numbers, not electricity consumption. For instance, in requesting cost information from the standard retailers as part of the review, IPART defined 'variable costs' as those costs that vary with each new or departing customer[23]. In its Final Decision for its 2010 price review, IPART then commented that the information provided by the standard retailers showed that the contribution of fixed costs to total ROC ranged from 76% to 77% and variable costs from 23% to 24%.[24]

Furthermore, in its advice to IPART as part of IPART's previous 2007 price review, Frontier Economics' discussion of the fixed and variable components of ROC implied that a large proportion of costs were fixed but that a small proportion of costs varied with customer numbers[25]. Nevertheless, Frontier recommended that the 25% of costs that were variable should be expressed on a dollars per MWh basis and IPART accepted this recommendation[26].

The Authority also notes that some retailers outsource their back office functions to a third party provider and are charged a fixed amount per customer account[27].

This suggests that the variable component of ROC identified by IPART and Frontier is one that varies with customer numbers, not with changes in electricity consumption. Since the fixed component of prices that the Authority is to determine is a cost per customer, option (b) would appear to be the appropriate approach to follow rather than option (a) where some part of the fixed per customer cost would have been recovered by a variable per MWh charge.

However, by determining different allowances for small, large and very large customers, the Authority has recognised that there may be a step-change in costs once a customer reaches a certain size.

Consistent with this approach, the Authority also considers that each customer should pay for ROC only once (regardless of the number of tariffs under which they may be supplied). For example, a residential customer may receive supply under tariffs 11, 31 and 33 given the different applications to which each of these tariffs applies. If a fixed ROC allowance was included in each tariff, this customer would in effect be paying three fixed (per customer) charges when only one was required. Therefore, the fixed ROC allowance will be applied to all retail tariffs except:

[23] IPART, *Review of Regulated Retail Tariffs and Charges for Electricity 2010-2013, Spreadsheet Model - Information Request*, July 2009.
[24] IPART, *Review of Regulated Retail Tariffs and Charges for Electricity 2010-2013, Final Report*, March 2010, p. 120.
[25] Frontier Economics, *Mass Market New Entrant Retail Costs and Retail Margin, Prepared for the Independent Pricing and Regulatory Tribunal*, March 2007, pp. 39-41.
[26] IPART, *Promoting Retail Competition and Investment in the NSW Electricity Industry: Regulated Electricity Retail Tariffs and Charges for Small Customers 2007 to 2010, Final Report and Final Determination*, June 2007, pp. 100-101.
[27] See, for instance: Australian Power and Gas, *Annual Report 2010/11*, October 2011, p. 23; and MBC Global, *Company Resume*, downloaded on 21 February 2012 from: http://www.mbcglobal.com.au/downloads/MBCResume.pdf.

(a) controlled load tariffs (Tariffs 31 and 33), because customers accessing these tariffs will also be supplied under one of the general supply residential tariffs (either Tariff 11 or Tariff 12); and

(b) unmetered tariffs (Tariffs 71 and 91), because customers accessing these tariffs are also likely to be supplied under another general supply business tariff.

Although this may not capture all circumstances where customers are accessing multiple tariffs, the rationalisation of tariffs is likely to reduce the possibility of customers paying ROC more than once.

The Authority's Draft Determination

For the purposes of the Draft Determination, the Authority will apply the relevant ROC allowance (for small, large and very large customers) to the fixed component of each retail tariff, as follows:

(a) the small customer ROC of $131 per customer per annum will apply to all residential tariffs and to other small customer tariffs where consumption is up to 100 MWh per annum (Tariffs 11, 12, 20, 22, 41 and the card meter tariff);

(b) the large customer ROC of $798 per customer will apply to tariffs where consumption is generally between 100 MWh and 4 GWh per annum (Tariffs 42, 43, 44 and 53);

(c) the very large customer ROC of $2,277 per customer will apply to tariffs where consumption is generally greater than 4 GWh per annum (Tariffs 54 and 55); and

(d) no ROC will apply to controlled load tariffs (Tariffs 31 and 33) or unmetered tariffs (Tariffs 71 and 91).

Table 4.5 converts these allowances to daily charges as will be applied in the relevant regulated retail tariffs for 2012-13.

Table 4.5: ROC Allowances for 2012-13

Retail Tariff	*Fixed charge (c/cust/day)*
11, 12, 20, 22, 41, card operated	35.887
42, 43, 44, 53	218.572
54, 55	623.873

4.4 Retail Margin

The retail margin represents the reward to investors for committing capital to a business and for accepting risks associated with providing retail electricity services. A retail margin which is not sufficient to compensate investors for their capital investment and exposure to systematic risks will lead to under-investment by existing retailers, deter entry into the market by new retailers and stall the development of effective competition.

4.4.1 Approach to Estimating the Retail Margin

In previous BRCI decisions, the Authority set the retail margin on an earnings before interest, tax, depreciation and amortisation (EBITDA) basis which meant that an allowance for depreciation and amortisation was implicitly included. It was also calculated as a percentage of total costs.

For the 2007-08 BRCI, by reference to retail margins accepted in other jurisdictions, the Authority concluded that a retail margin of 5% appeared appropriate. The 5% margin was maintained for all subsequent BRCI decisions because the Authority considered that there was no evidence to suggest that the risks of retailing electricity in Queensland had changed from one year to the next and that changes in all other cost components had been captured elsewhere in the BRCI methodology.

In its Draft Methodology Paper, the Authority noted that the retail margin should compensate retailers for systematic risks while non-systematic risks are compensated for elsewhere in the determination. Systematic risks are the result of exposure to overall economic or market conditions (also known as economic, market or non-diversifiable risk).

The Authority considered two alternative approaches to estimating the retail margin:

(a) undertaking an extensive and detailed financial analysis of the appropriate retail margin, such as a bottom-up and/or expected returns approach; or

(b) assessing the appropriateness of the current retail margin by benchmarking it against margins adopted in other jurisdictions.

Approaches in Other Jurisdictions

Consistent with the Authority's approach under the BRCI, other regulators calculate the retail margin on an EBITDA basis and (except in South Australia) calculate the margin as a percentage of total costs. In South Australia, the margin is calculated as a percentage of 'controllable costs' (that is, including retail and energy costs but excluding network costs).

While it is clear that the margin is intended to compensate retailers for their exposure to systematic risks in some jurisdictions (such as NSW), it is often not clear what risks are being compensated for in other jurisdictions. The most recent approaches adopted by regulators to estimate the retail margin in other jurisdictions are summarised below.

IPART (NSW)

Of all the regulators, IPART has undertaken the most extensive analysis in estimating the retail margin for its most recent determination. It engaged SFG Consulting (SFG) to provide advice on a feasible range for the margin using three alternative approaches - expected returns, benchmarking and bottom up. IPART then selected the mid-point of the range for each approach and applied an equal weighting to each. The resulting 5.4% margin it selected was consistent with the mid-point of the reasonable range recommended by SFG.

ESCOSA (South Australia)

ESCOSA engaged LECG to advise on the retail margin for its most recent determination. LECG undertook a combination of benchmarking and a return on investment analysis (based on financial data provided by the regulated business). However, ESCOSA noted that it had relied more heavily on the results of the benchmarking analysis in arriving at its estimate of 10% of controllable costs (approximately 5.2% of total costs), given the numerous assumptions and judgements that were required in developing the bottom-up margin estimate.

ICRC (ACT)

The ICRC paid particular attention to the margin estimated by IPART given the extensive analysis underpinning that estimate. However, in adopting the same margin as IPART (5.4%), it considered that this may slightly over-compensate the regulated retailer for the risks it faces, given that compensation for energy purchase cost risks was already provided in the energy cost allowance and the broad range of matters eligible for pass through to retail prices.

OTTER (Tasmania)

OTTER adopted a combination of benchmarking and return on investment analysis to estimate a retail margin of 3.7%. In adopting a lower retail margin than other jurisdictions, OTTER noted that the regulated retailer faced significantly lower energy price and volume risk than retailers in those jurisdictions[28].

Submissions

In response to the Issues Paper, most retailers maintained that the current retail margin of 5% was too low, although QEnergy considered that it was, nevertheless, reasonable. Of consumer groups, QCOSS considered that the current margin was realistic, but noted that it could arguably be lower, while CCIQ considered that it was too high.

Despite commenting on the appropriate level of the margin and, in some cases, the risks that should be compensated for, submissions did not suggest an appropriate estimation approach. However, both Origin Energy and Ergon Energy recommended that the Authority should have regard to the extensive analysis conducted by SFG for IPART's most recent price review.

Following the release of the Draft Methodology Paper, Origin Energy, Queensland Government and CCIQ supported benchmarking to estimate the retail margin. However, Ergon Energy argued that a simple benchmarking analysis would not provide adequate compensation for current financial market volatility and the rising cost of debt and equity. It instead argued that the retail margin should be determined by assessing the appropriate systematic return for the representative retailer, as SFG had done for IPART.

The Authority's Position

While, as suggested by Ergon Energy, an extensive and detailed analysis of the appropriate retail margin might ensure adequate compensation to retailers for current financial market volatility, the Authority was not convinced that it would deliver significant benefits over the benchmarking approach.

For instance, despite extensive analysis, IPART still needed to exercise judgement to select an appropriate margin within a relatively wide recommended range of 4.8% to 6%. Furthermore, benchmarking is likely to implicitly take account of current financial market volatility. For instance, IPART noted its valuations of the weighted average cost of capital (WACC) (which were used to model the retail margin) were '... commensurate with prevailing market conditions and reasonably reflect the post-global financial crisis environment.'[29]

[28] OTTER, *Investigation of Maximum Prices for Declared Retail Electricity Services on Mainland Tasmania, Final Report*, October 2010, p. 80, pp. 89-99.
[29] IPART, *Review of Regulated Retail Tariffs and Charges for Electricity 2010-2013, Final Report*, March 2010, p. 232 & p. 234.

Therefore, given the general support for benchmarking in submissions, the Authority has decided to assess the appropriateness of the current margin of 5% by benchmarking it against margins adopted in other jurisdictions.

4.4.2 Implementing the Benchmarking Approach

The retail margins adopted in relevant jurisdictions are provided in Table 4.6 below. As noted above, all jurisdictions set the retail margin on an EBITDA basis.

Table 4.6: Retail Margin in NEM Jurisdictions

	Regulatory Period	*EBITDA Retail Margin (% of total costs)*
Queensland (current)	July 2011 – June 2012	5%
NSW (IPART)	July 2010 – June 2013	5.4%
South Australia (ESCOSA)[1]	January 2011 – June 2014	5.2%
ACT (ICRC)	July 2010 – June 2012	5.4%
Tasmania (OTTER)	July 2010 to June 2013	3.7%

1. Applied as 10% of controllable costs (energy costs + ROC) but converted for comparison purposes. See: ESCOSA, 2010 Review of Retail Electricity Standing Contract Price Path: Final Inquiry Report & Final Price Determination, December 2010, p. A-92; and Sapere Research Group, 2011 Review of the South Australia gas standing contract retail operating cost and retail operating margin: Report to the Essential Services Commission of South Australia, April 2011, p. 53.

The retail margins adopted in NSW, South Australia and ACT are slightly higher than the 5% margin currently adopted by the Authority. While the retail margin adopted in Tasmania is much lower, it is unlikely to be a relevant comparator as it reflects OTTER's view (as noted above) that the regulated retailer (which is the monopoly provider of retail services to non-contestable customers in Tasmania) faces significantly lower energy price and volume risk than retailers in other NEM jurisdictions[30].

The retail margin decisions in South Australia and the ACT were heavily reliant on benchmarking against other regulatory decisions and are therefore considered less relevant than the IPART decision, where a much more comprehensive analysis was undertaken. For this reason, the Authority has paid particular regard to the analysis underpinning the IPART estimate and has considered its applicability to a representative Queensland retailer.

IPART Approach

In estimating the retail margin, IPART's objective was to compensate the regulated retailers for the systematic risks they face, including:[31]

(a) the risk of variation in their regulated load profile due to changes in economic conditions that affect the demand for their electricity;

[30] OTTER, *Investigation of Maximum Prices for Declared Retail Electricity Services on Mainland Tasmania, Final Report*, October 2010, p. XXXII, p. 80 & pp. 89-99.

[31] IPART, *Review of Regulated Retail Tariffs and Charges for Electricity 2010-2013, Final Report*, March 2010, p. 128.

(b) the risk of variation in wholesale electricity spot and contract prices due to changes in economic conditions and demand; and

(c) general business risk due to changes in economic conditions.

IPART engaged SFG to provide advice on a feasible range for the retail margin using three alternative approaches – expected returns, benchmarking and bottom up[32].

Expected Returns Approach

The expected returns approach was applied by estimating the cashflows that a retailer would earn from small customers and a retail margin was estimated to compensate investors for the systematic risk associated with these cashflows.

Using this approach, SFG estimated a range of 3.4% to 4.8%, with a mid-point of 4.1% – the lowest of all three approaches.

Bottom-up Approach

The bottom-up approach was applied by starting with an assumed investment base and cost estimates, then determining the earnings and revenue which would allow the retailer to earn an expected return equal to its estimated cost of capital.

Using this approach, SFG estimated a range of 4.5% to 6.3%, with a mid-point of 5.4%.

Benchmarking Approach

The benchmarking approach was applied by examining the reported profit margins of over 300 retailers across six sub-industries in Australia, the United States and the United Kingdom over a 29-year period. SFG also considered the profit margins of retail energy businesses in Australia.

Using this approach, SFG estimated a range of 6.4% to 6.9%, with a mid-point of 6.7% – the highest of all three approaches.

Summary

SFG applied equal weight to each of the estimates derived from the three methodologies, in the absence of evidence that any one of the methodologies was more reliable than the other. Based on SFG's advice, IPART selected the mid-point of the range for each approach and applied an equal weighting to each. The resulting 5.4% margin it selected was consistent with the mid-point of the reasonable range of 4.8% to 6% recommended by SFG.

The Authority's Position

The determination of an appropriate retail margin is an imprecise exercise. The Authority has previously noted that its current retail margin of 5% falls within the reasonable range of 4.8% to 6% suggested by SFG. Furthermore, IPART noted that it could have exercised its regulatory discretion to use any margin within that range, but exercised its judgement in selecting the mid-point of 5.4%. In this context, the current 5% margin in Queensland is not unreasonable.

However, the Authority notes that some retailers (including TRUenergy, Origin Energy and AGL) have argued that the risks of retailing in Queensland are greater than those in NSW and that a higher retail margin is warranted. For instance, TRUenergy argued that NSW has:

[32] SFG Consulting, *Estimation of the Regulated Profit Margin for Electricity Retailers in New South Wales*, 16 March 2010.

(a) well defined cost pass-through provisions; and

(b) a more stable and predictable regulatory process with retail costs and the margin being set for three years, network tariffs being passed through and annual reviews of energy purchase costs under a set methodology.

While the Authority is not able to incorporate a cost pass-through mechanism in its determination (see Chapter 6), this is a less significant issue in Queensland where regulated prices are set for one year, than it would be in NSW where prices are set for a three-year period. The longer the price path, the higher the risks of costs differing from forecasts or unforeseen events arising that might have a significant influence (up or down) on previously estimated costs. While a longer price path may provide greater stability and predictability to retailers, the new pricing approach being established in this determination should reduce the risks faced by retailers in Queensland relative to the previous BRCI approach, including better alignment of the cost structure and price structure and the pass through of network costs.

TRUenergy and Origin Energy also argued that the inclusion of a LRMC floor in the NSW energy cost allowance provided certainty and reduced retailers' risks and that the Queensland retail margin should be higher to account for this. QEnergy argued that setting prices by reference to the LRMC had been an implicit source of headroom in tariffs (which is not the purpose of the retail margin). While the Authority has rejected the idea of basing its energy cost estimates on the LRMC (of generation) or including an LRMC floor to energy costs, the inclusion of an LRMC floor in NSW will reduce the risk exposure of retailers in that state. However, the Authority has considered the issue of headroom explicitly in Chapter 6.

The Authority's Draft Determination

Given the detailed analysis undertaken by IPART, it would seem reasonable for the retail margin in Queensland to be lifted to be the same as that adopted by IPART.

The Authority has therefore set the retail margin at 5.4% of total allowed costs, inclusive of the margin,[33] which is equivalent to applying a margin of 5.7% on top of total allowed costs.

[33] The Authority (under the BRCI) and IPART both expressed the retail margin in this manner. The Authority's previous 5% margin under the BRCI was equivalent to applying a margin of 5.26% on top of allowed costs.

5. COST-REFLECTIVE RETAIL TARIFFS AND PRICES

Under the N+R approach, retail tariffs are to be aligned with network tariffs. Chapter 2 set out the Authority's consideration of the relevant network tariffs (the N component), upon which retail tariffs are to be based.

Chapters 3 and 4 set out the Authority's consideration of energy costs and retail costs (ROC and the retail margin) which together comprise the R component of retail tariffs.

This chapter brings together the network tariffs and prices with the energy and retail operating cost estimates from those earlier chapters then adds on the retail margin to arrive at the bundled (cost-reflective) retail tariffs and prices.

5.1 Network Costs

As discussed in Chapter 2, the Authority has based the 2012-13 regulated retail tariffs on network tariffs drawn from both Energex and Ergon Energy as follows:

(a) Ergon Energy network tariffs and charges for non-residential customers with consumption greater than 100 MWh per year and for street lighting;

(b) Energex network tariffs and charges for all other customers, including unmetered loads other than street lighting; and

(c) a consumption-weighted average of rates for the first two steps of Energex's IBT for customers on card operated meters.

The network charges applicable to each retail tariff include fixed and variable charges, as well as demand and capacity charges for some tariffs, which reflect the make-up of costs incurred by the network operator.

The network tariffs and charges form the basis of the regulated retail tariffs presented in Tables 5.1, 5.2 and 5.3.

5.2 Energy Costs

As discussed in Chapter 3, the Authority estimated energy costs for each retail tariff directly on a dollars per MWh basis. This reflects the manner in which retailers incur costs because energy costs are entirely dependent on the level (and time) of consumption, the more one consumes the more it costs.

In order to achieve cost reflectivity, the relevant energy cost estimate for each retail tariff has been applied to the variable component of that tariff as follows:

(a) 7.823 cents per kWh for tariffs where consumption is settled on the Energex NSLP (tariffs 11, 12, 20, 22, 41 and the card-operated tariff);

(b) 7.167 cents per kWh for tariffs where consumption is settled on the Ergon Energy NSLP (tariffs 42, 43, 44, 53, 54 and 55);

(c) for controlled load tariffs:

 (i) 5.709 cents per kWh for the night rate (super economy) tariff (tariff 31); and

 (ii) 6.492 cents per kWh for the controlled supply (economy) tariff (tariff 33); and

(d) 5.786 cents per kWh for the unmetered tariffs (tariffs 71 and 91).

The energy costs that have been applied to each regulated retail tariff are shown in Tables 5.1, 5.2 and 5.3.

5.3 Retail Operating Costs

As discussed in Chapter 4, the Authority estimated three different fixed per customer ROC allowances for customers of different sizes – small, large and very large – which have been applied to the fixed component of each retail tariff, as follows:

(a) 35.887 cents per customer per day has been applied to residential tariffs and tariffs where consumption is less than 100 MWh per annum (tariffs 11, 12, 20, 22, 41 and the card-operated tariff);

(b) 218.572 cents per customer per day has been applied to tariffs where consumption is generally between 100 MWh and 4 GWh per annum (tariffs 42, 43, 44 and 53);

(c) 623.873 cents per customer per day has been applied to tariffs where consumption is generally greater than 4 GWh per annum (tariffs 54 and 55); and

(d) no ROC has been applied to controlled load tariffs (tariffs 31 and 33) or unmetered tariffs (tariffs 71 and 91).

The ROC that will apply to each regulated retail tariff is shown in Tables 5.1, 5.2 and 5.3.

5.4 Retail Margin

As discussed in Chapter 4, the Authority has decided to set the retail margin at 5.7% on top of total costs excluding the margin (and the allowance for headroom discussed in Chapter 6).

Given that the retail margin is calculated as a percentage of total costs, the appropriate approach is to apply the retail margin equally (on a percentage basis) to each component (fixed, variable, demand and capacity) of each retail tariff. This will mean that all customers pay the same margin as a percentage of their total bill but, in dollar terms, larger customers will pay more than smaller customers. In response to the Draft Methodology Paper, QCOSS, Origin Energy and CCCIQ generally supported this approach.

While the Authority acknowledges that there may be justification for applying different margins to different customer groups (as suggested by Ergon Energy) on the basis of differences in risk, it considers that this would be highly subjective and, therefore, is not inclined to go down that path.

The retail margin that will apply to each regulated retail tariff is shown in Tables 5.1, 5.2 and 5.3.

5.5 Cost-Reflective Retail Tariffs

Table 5.1: Cost-Reflective 2012-13 Residential Regulated Retail Tariffs (GST Exclusive)

Retail tariff	*Energex network tariff*	*Tariff component*	*Fixed charge* c/cust/day	*Variable rate (flat)* c/kWh	*Variable rate 1*[a] c/kWh	*Variable rate 2*[b] c/kWh	*Variable rate 3*[c] c/kWh
Tariff 11 - Residential (inclining block)	8400	Network	35.000		7.905	15.020	18.973
		Energy			7.823	7.823	7.823
		Retail	35.887				
		Margin	4.041		0.896	1.302	1.527
		Total	*74.928*		*16.624*	*24.145*	*28.323*
Tariff 12 - Residential (time of use)	8900	Network	35.000		7.496	11.369	23.525
		Energy			7.823	7.823	7.823
		Retail	35.887				
		Margin	4.041		0.873	1.094	1.787
		Total	*74.928*		*16.192*	*20.286*	*33.135*
Tariff 31 - Night rate (super economy)	9000	Network		4.161			
		Energy		5.709			
		Retail					
		Margin		0.563			
		Total		*10.433*			
Tariff 33 - Controlled supply (economy)	9100	Network		7.613			
		Energy		6.492			
		Retail					
		Margin		0.804			
		Total		*14.909*			

a. First 13.69 kWh per day for Tariff 11, off-peak consumption for Tariff 12.
b. Next 13.69 kWh per day for Tariff 11, shoulder consumption for Tariff 12.
c. Remaining kWh per day for Tariff 11, peak consumption for Tariff 12.

Table 5.2: Cost-Reflective 2012-13 Small Customer Regulated Retail Tariffs and Unmetered Supplies Other Than Street Lighting (GST Exclusive)

Retail tariff	*Energex network tariff*	*Tariff component*	*Fixed charge* c/cust/day	*Demand charge* $/kW/month	*Variable rate (flat)* c/kWh	*Variable rate (off peak)* c/kWh	*Variable rate (peak)* c/kWh
Tariff 20 - Business (flat rate)	8500	Network	64.000		10.152		
		Energy			7.823		
		Retail	35.887				
		Margin	5.694		1.025		
		Total	*105.581*		*19.000*		
Tariff 22 - Business (time of-use)	8800	Network	64.000			8.451	10.341
		Energy				7.823	7.823
		Retail	35.887				
		Margin	5.694			0.928	1.035
		Total	*105.581*			*17.202*	*19.199*
Tariff 41 - Low voltage (demand)	8300	Network	1501.000	17.753	1.017		
		Energy			7.823		
		Retail	35.887				
		Margin	87.603	1.012	0.504		
		Total	*1624.490*	*18.765*	*9.344*		
Tariff 91 - Unmetered	9600	Network			8.137		
		Energy			5.786		
		Retail					
		Margin			0.794		
		Total			*14.717*		
Card-operated (remote communities)	8400	Network	35.000		10.339		
		Energy			7.823		
		Retail	35.887				
		Margin	4.041		1.035		
		Total	*74.928*		*19.197*		

Table 5.3: Cost-Reflective 2012-13 Large Customer Regulated Retail Tariffs and Street Lighting (GST Exclusive)

Retail tariff	*Ergon Energy network tariff*	*Tariff component*	*Fixed charge*	*Demand charge*	*Capacity charge*	*Variable rate (Flat)*
			c/cust/day	*$/kW/month*	*$/kW/month*	*c/kWh*
Tariff 42 - Over 100 MWh small (demand)	EDST1	Network	494.900	27.115		1.579
		Energy				7.167
		Retail	218.572			
		Margin	40.668	1.546		0.499
		Total	*754.140*	*28.661*		*9.245*
Tariff 43 - Over 100 MWh medium (demand)	EDMT1	Network	1995.000	23.307		1.579
		Energy				7.167
		Retail	218.572			
		Margin	126.174	1.328		0.499
		Total	*2339.746*	*24.635*		*9.245*
Tariff 44 - Over 100MWh large (demand)	EDLT1	Network	3271.800	22.336		1.579
		Energy				7.167
		Retail	218.572			
		Margin	198.951	1.273		0.499
		Total	*3689.324*	*23.609*		*9.245*
Tariff 53 - High voltage (demand)	EDHT1	Network	2059.500	17.890		1.541
		Energy				7.167
		Retail	218.572			
		Margin	129.850	1.020		0.496
		Total	*2407.922*	*18.910*		*9.204*
Tariff 54 - Connection Asset Customers	EE CAC	Network	52492.900	5.246	10.713	0.811
		Energy				7.167
		Retail	623.873			
		Margin	3027.656	0.299	0.611	0.455
		Total	56144.429	5.545	11.324	8.433
Tariff 55 - Individually Calculated Customers	EE ICC	Network	245787.2	3.006	4.905	2.355
		Energy				7.167
		Retail	623.873			
		Margin	14045.431	0.171	0.280	0.543
		Total	*260456.504*	*3.177*	*5.185*	*10.065*
Tariff 71 - Street lighting	EVUT1	Network	23.900			9.253
		Energy				5.786
		Retail				
		Margin	1.362			0.857
		Total	*25.262*			*15.896*

a. The fixed charge for street lighting applies to each lamp, not each customer.

6. COMPETITION, TRANSITIONAL AND OTHER ISSUES

This chapter discusses other issues relevant to the price determination process that have not been dealt with elsewhere, namely:

(a) the impact of the Authority's price determination on competition in the Queensland retail electricity market;

(b) transitional arrangements for customers facing significant price increases; and

(c) the eligibility criteria and other terms and conditions pertaining to retail tariffs.

6.1 Competition Considerations

Whether to Make an Allowance for Head Room

In response to the Draft Methodology Paper, retailers were generally of the view that the Authority had not given sufficient consideration to the potential impact of its proposed methodology on competition. They suggested that to maintain the current level of competition would require maintaining the excess profit, or 'head room', included to varying degrees in the existing regulated retail tariffs.

The Delegation requires that, in calculating notified prices, the Authority should ensure its price determination has regard to the effect of the determination on competition in the Queensland retail electricity market, consistent with the Government's policy objective that consumers, wherever possible, have the opportunity to benefit from competition and efficiency in the market place.

This suggests that there is some longer term benefit to be derived by maintaining an actively competitive market rather than pursuing a short term minimum price approach which may stifle or eliminate competition from the market.

The longer term benefit derives from the downward pressure on prices that competition naturally brings to the market. By setting regulated prices somewhat higher than full cost, retailers will be attracted to enter the market and, as they compete for market share, non-regulated prices will be driven down. The more active the competition, the closer retailers will reduce prices to their individual, efficient costs of supply. While regulated prices will be unaffected, customers should be able to access lower priced market offers from competing retailers.

As the Delegation directs the Authority to have regard to both the actual costs of supply and the impact of its determination on competition, this suggests that some trade-off is to be made between these twin objectives. Allowing for some head room above the efficient costs of supply (as presented in Chapter 5) will, as the retailers noted, sustain an actively competitive market.

If the cost of supplying consumers was fairly even across the State, it would be a relatively simple matter to determine an amount of head room to include in regulated prices. The more head room, the greater the level of competition and the more resulting market prices (as opposed to regulated prices) would be squeezed down as retailers battled to attract customers. However, it is unlikely that any reasonable level of head room allowed in the Energex network area would be sufficient to encourage retailers to offer market contracts to small customers in Ergon Energy's network area. As a result, customers in the majority of the State will have to pay the regulated price, inclusive of any allowance for head room, and hence the trade-off between actual costs and competition is more complex.

How Much Head Room to Allow

Having decided to include some allowance in notified prices for head room, the question is what level of head room to allow.

Under the BRCI approach, the Authority was specifically required to maintain head room but never had to consider what the level of head room in existing tariffs was, as it assumed that, having reflected changes in all underlying costs, any head room (whatever it was) should have been maintained (in an aggregate sense).

In other jurisdictions where retail electricity prices are regulated, no regulators include an explicit allowance for head room. However, in NSW and South Australia, IPART[34] and ESCOSA[35] both noted that certain aspects of the way they calculated regulated prices meant that new entrant retailers could face lower costs, for example, by supplying more than the regulated load or by using lower cost energy trading strategies. Both regulators examined the state of competition in their markets and found that the regulated price was not a major barrier to entry in the respective markets.

In contrast, in its 2010-12 price determination for the ACT, the ICRC set the regulated price based on the actual costs incurred by the sole incumbent retailer, on the basis that this price was likely to be lower than any competitive price that might result if the regulated rate was set higher to encourage competition in the market.

The concept of head room to facilitate competition is not relevant in Western Australia and Tasmania because small customers are currently not contestable, nor in the Northern Territory, where the only licensed retailer for small customers is subsidised.

In submissions, retailers suggested that the head room available in existing prices was integral to the development of competition in the Queensland market. While retailers generally suggested that the Authority needed to include an allowance for head room in 2012-13 prices sufficient to ensure that the current level of competition is maintained, only QEnergy quantified this, suggesting that the way notified tariffs were originally set meant that there was 20% and 30% head room in residential and business tariffs respectively.

An analysis of the most common 2011-12 notified prices suggests that a number of them, particularly non-residential tariffs, may be significantly higher than the efficient cost of supply.

Figure 6.1 presents a cost breakdown of the annual (2011-12) electricity bill for an average customer on notified prices under a group of common tariffs.

Figure 6.1 is based on:

(a) Energex network costs (distribution use of system (DUOS) plus TUOS), given that most of the customers supplied by retailers operating in the competitive market in Queensland are located in Energex's network area; and

(b) other cost estimates calculated for the 2011-12 BRCI. While different stakeholders disagreed with different aspects of these costs, the approach is well understood and has been used as the basis of comparison by retailers with their costs. In particular, retailers have consistently argued that the BRCI under-estimated their actual costs of supply.

[34] IPART, *Review of Regulated Retail Tariffs and Charges for Electricity 2010-2013, Final Report*, March 2010

[35] ESCOSA, *2010 Review of Retail Electricity Standing Contract Price Path, Final Inquiry Report and Final Price Determination*, December 2010.

As the cost breakdown is for a customer with an average level of consumption for the particular tariff, the estimates of head room would be lower for below-average levels of consumption and higher for above-average levels of consumption because the fixed charges in notified prices do not fully reflect the fixed network and retail costs of supplying customers. As a result, retailers would recover less revenue relative to costs for smaller customers and more revenue relative to costs for larger customers.

As shown in Figure 6.1, the level of head room in Tariff 11 in 2011-12 is estimated to be around 6% whereas the level of head room in most other common tariffs is much higher, ranging between 12% and 23%.

Figure 6.1: Cost Breakdown of Average Annual Electricity Bill in 2011-12 by Tariff Class

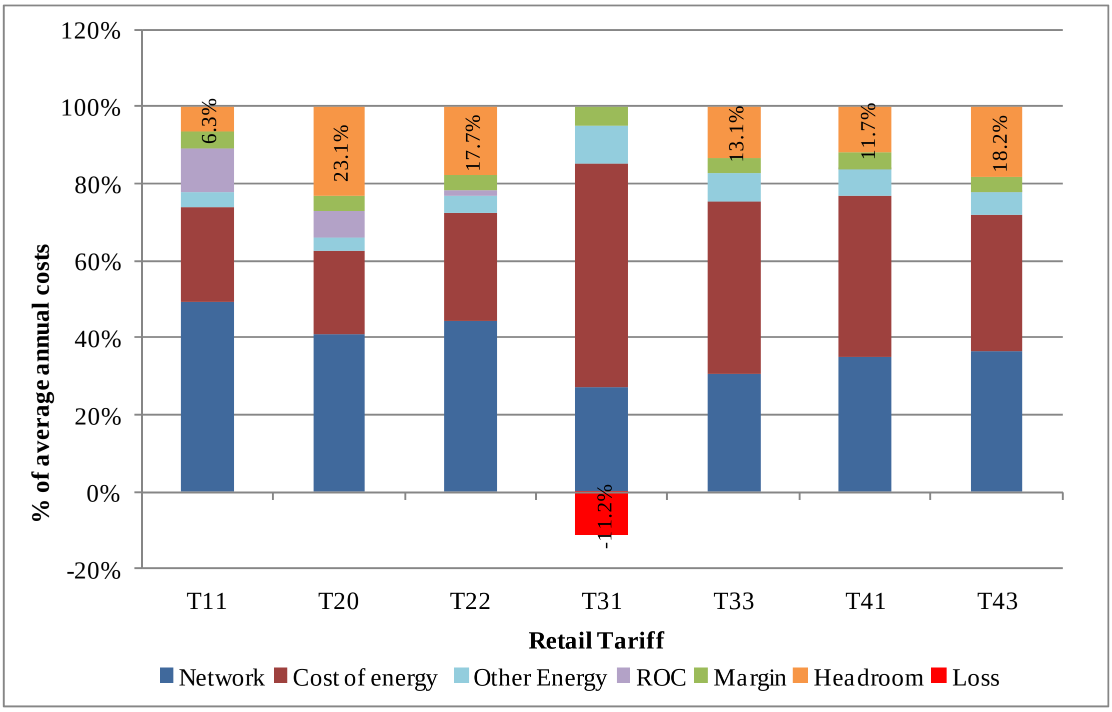


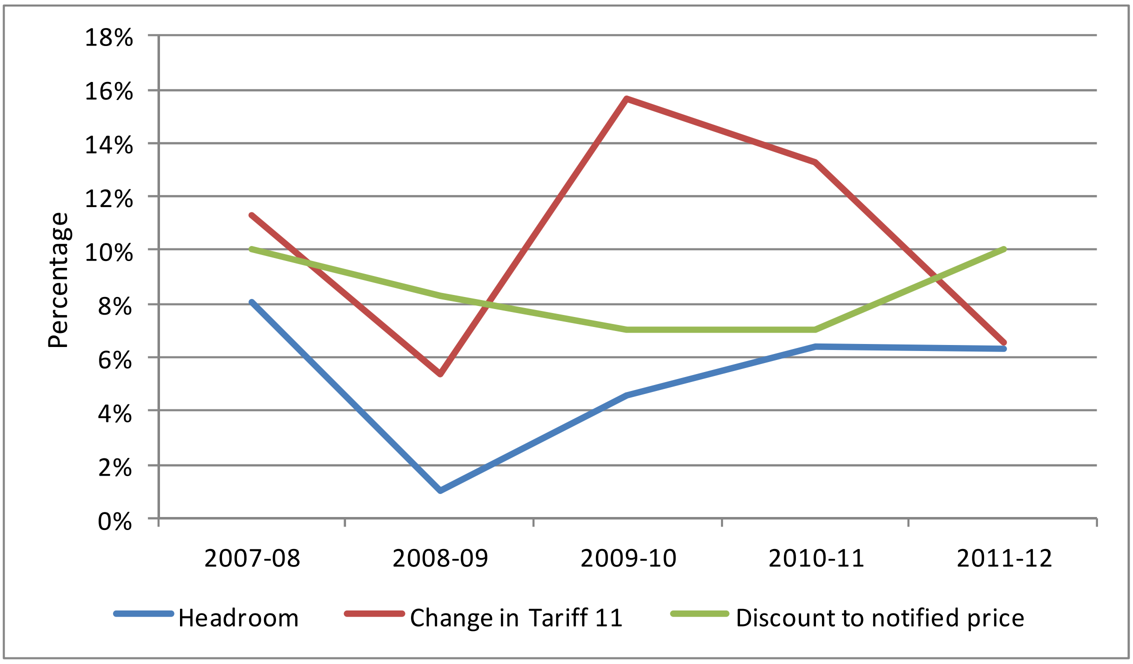
Figure based on 2011-12 Energex network tariffs, 2011-12 BRCI cost inputs (Cost of Energy $55.47/MWh, other energy costs (SRES, GEC, market fees etc.) $9.21/MWh, ROC $131.90, and margin 5%) and average consumption by network tariff (as provided by Energex).

However, this analysis is not without its problems. For example, the negative head room (indicating an annual loss to retailers) shown for Tariff 31 is not likely to be correct and highlights a weakness of the BRCI approach in that it did not reflect differences in costs of supplying different tariffs. In reality, retailers would most likely incur lower energy costs for supplying controlled load tariffs than for other tariffs where energy costs are settled based on the NSLP.

Nevertheless, the residential market (Tariff 11) comprises by far the largest number of customers and consumption and is also the market segment where there is reasonable information on discounts to the notified price offered in market contracts by retailers and other statistics such as churn rates.

Figure 6.2 shows how prices, discounts and head room for Tariff 11 have varied since the start of FRC.

Figure 6.2: Head Room, Available Discounts and BRCI Price Increases in Tariff 11



Discounts to the notified price reflect the maximum discounts based on offers available on the Authority's Price Comparator, including equivalent discounts for one month free offers.

Since the commencement of FRC, the estimated level of (effective) head room in Tariff 11 has averaged 5.3%. The low level of head room in 2008-09 resulted from the initial BRCI increase for that year of 5.38% which was increased following judicial review, but applied to notified prices for all but the last five minutes of 2008-09. The following 15.5% increase in notified prices between 2008-09 and 2009-10 reflects the extra 3.68% increase to 2008-09 prices that resulted from the re-made decision after judicial review in addition to the BRCI increase for 2009-10 of 11.82%.

Given the importance of price to customers in choosing to take up a market contract with a retailer, discounts to the notified price offered by retailers may also provide an indication of the level of head room available to retailers in Tariff 11.

As shown in Figure 6.2, the maximum discount to the notified price offered by retailers under market contracts has ranged between 7% and 10% since the commencement of FRC. However, on average, the level of discounting is likely to be somewhat less than this as the maximum discount offered does not apply to all products nor is it necessarily available throughout the entire year. This may explain why the level of discounting shown in Figure 6.2 is always higher than the level of head room.

The above analysis suggests that there is a reasonably modest amount of head room of around 6% currently in Tariff 11. While the Authority has no data on retailers' actual costs, as retailers consistently argued in the past that the BRCI underestimated their actual costs, it would seem reasonable to conclude that actual head room is no greater than the levels suggested in Figure 6.2.

This is contrary to claims by QEnergy that head room is actually significantly greater than 6%. For this to be true, the BRCI must have substantially over-estimated retailers' actual costs. If this was the case, it would have implications for setting some elements of notified prices for 2012-13 given the similar approach to estimating some costs under the BRCI and the current process. However, the Authority has not yet made any changes to cost estimates for this reason as it is not clear what other retailers' views might be on the existing level of head room.

As the Authority does not have any information about the level of discounts that may have been offered by retailers in market contracts for customers on tariffs other than Tariff 11, it is not possible to duplicate the above analysis for other tariff categories. However, given that the available head room in Tariff 11 appears to have been sufficient to foster a healthy amount of competition in the market for residential customers, the Authority considers that the same level of head room is likely to be sufficient to support competition for customers on notified prices under all other regulated tariffs.

The Authority's Position

For the purposes of this Draft Determination, the Authority has decided to include an additional allowance for head room of 5% of cost-reflective prices for all tariffs, as shown in Tables 6.1 to 6.3.

Table 6.1: Residential Regulated Retail Tariffs for 2012-13, Including Head Room (GST Exclusive)

Retail tariff	*Tariff component*	*Fixed charge*	*Variable rate (flat)*	*Variable rate 1*[a]	*Variable rate 2*[b]	*Variable rate 3*[c]
		c/cust/day	*c/kWh*	*c/kWh*	*c/kWh*	*c/kWh*
Tariff 11 - Residential (inclining block)	Cost-reflective tariff	74.928		16.624	24.145	28.323
	Head room	3.746		0.831	1.207	1.416
	Total	*78.674*		*17.456*	*25.352*	*29.740*
Tariff 12 - Residential (time-of-use)	Cost-reflective tariff	74.928		16.192	20.286	33.135
	Head room	3.746		0.810	1.014	1.657
	Total	*78.674*		*17.002*	*21.300*	*34.792*
Tariff 31 - Night rate (super economy)	Cost-reflective tariff		10.433			
	Head room		0.522			
	Total		*10.954*			
Tariff 33 - Controlled supply (economy)	Cost-reflective tariff		14.909			
	Head room		0.745			
	Total		*15.654*			

a. First 13.69 kWh per day for Tariff 11, off-peak consumption for Tariff 12
b. Next 13.69 kWh per day for Tariff 11, shoulder consumption for Tariff 12.
c. Remaining kWh per day for Tariff 11, peak consumption for Tariff 12.

Table 6.2: Small Business Regulated Retail Tariffs for 2012-13 and Unmetered Supplies Other Than Street Lighting, Including Head Room (GST Exclusive)

Retail tariff	*Tariff component*	*Fixed charge*	*Demand charge*	*Variable rate (flat)*	*Variable rate (off peak)*	*Variable rate (peak)*
		c/cust/day	*$/kW/month*	*c/kWh*	*c/kWh*	*c/kWh*
Tariff 20 - Business (flat rate)	Cost-reflective tariff	105.581		19.000		
	Head room	5.279		0.950		
	Total	*110.860*		*19.950*		
Tariff 22 - Business (time-of-use)	Cost-reflective tariff	105.581			17.202	19.199
	Head room	5.279			0.860	0.960
	Total	*110.860*			*18.062*	*20.159*
Tariff 41 - Low voltage (demand)	Cost-reflective tariff	1624.490	18.765	9.344		
	Head room	81.224	0.938	0.467		
	Total	*1705.714*	*19.703*	*9.811*		
Tariff 91 - Unmetered	Cost-reflective tariff			14.717		
	Head room			0.736		
	Total			*15.452*		
Card operated (remote communities)	Cost-reflective tariff	74.928		19.197		
	Head room	3.746		0.960		
	Total	*78.674*		*20.157*		

Table 6.3: Large Business Regulated Retail Tariffs for 2012-13 and Street Lighting, Including Head Room (GST Exclusive)

Retail tariff	*Tariff component*	*Fixed charge* *c/cust/day*	*Demand charge* *$/kW/month*	*Capacity charge* *$/kW/month*	*Variable rate (Flat)* *c/kWh*
Tariff 42 - Over 100 MWh small (Demand)	Cost-reflective tariff	754.140	28.661		9.245
	Head room	37.707	1.433		0.462
	Total	*791.847*	*30.094*		*9.707*
Tariff 43 - Over 100 MWh medium (Demand)	Cost-reflective tariff	2339.746	24.635		9.245
	Head room	116.987	1.232		0.462
	Total	*2456.733*	*25.867*		*9.707*
Tariff 44 - Over 100MWh large (demand)	Cost-reflective tariff	3689.324	23.609		9.245
	Head room	184.466	1.180		0.462
	Total	*3873.790*	*24.790*		*9.707*
Tariff 53 - High voltage (demand)	Cost-reflective tariff	2407.922	18.910		9.204
	Head room	120.396	0.945		0.460
	Total	*2528.319*	*19.855*		*9.665*
Tariff 54 - Connection Asset Customers	Cost-reflective tariff	56144.429	5.545	11.324	8.433
	Head room	2807.221	0.277	0.566	0.422
	Total	58951.651	5.822	11.890	8.854
Tariff 55 - Individually Calculated Customers	Cost-reflective tariff	260456.504	3.177	5.185	10.065
	Head room	13022.825	0.159	0.259	0.503
	Total	*273479.330*	*3.336*	*5.444*	*10.568*
Tariff 71 - Street lighting[a]	Cost-reflective tariff	25.262			15.896
	Head room	1.263			0.795
	Total	*26.525*			*16.691*

a. *The fixed charge for street lighting applies to each lamp, not each customer.*

6.2 Transitional Arrangements

The Delegation requires the Authority to consider whether any transitional arrangements should be provided for farming and irrigation customers required to move to an alternative tariff, customers currently on obsolete and declining block tariffs and street lighting customers currently on Tariff 71. The Authority has not been directed to consider transitional arrangements for other tariff categories. Indeed, apart from the tariffs that the Authority has been directed to consider transitioning for, the Authority is required to ensure that prices are cost-reflective and any transitioning necessarily means a departure from cost reflectivity for the period of the transitioning.

The Authority is not required to consider transitional arrangements for other tariff categories. However, in Chapter 7 it has looked at the impacts of the new tariffs and prices on remaining customer groups. The Authority is first required to consider the actual costs of supplying electricity, that is, to develop cost-reflective prices. By its very nature, transitioning would require some departure from that course for the period of the transitioning.

In the Issues Paper, the Authority noted the importance of providing customers with sufficient time to make informed decisions about the impact of any changes on their bills. Given that new tariffs will be introduced on 1 July 2012, it suggested that it may be appropriate to provide additional time for those customers who are required to change tariffs to make these decisions.

The Authority also suggested that some form of transitional arrangements may be required where customers currently supplied under tariffs that are not cost-reflective face significant price increases if they are immediately moved to a cost-reflective tariff. However, the Authority noted that a balance needed to be struck between the efficiency benefits of achieving cost-reflective tariffs and the need to protect customers from significant price shocks.

Submissions

In submissions received, consumer groups strongly supported the inclusion of transitional arrangements due to concerns about the potential for price and other impacts from implementing new regulated retail tariffs on 1 July 2012.

For example, the Bundaberg Regional Irrigators Group (BRIG) noted that there had been significant investment in irrigation equipment based on the characteristics of specific tariffs and suggested that two years notice of any tariff changes was required to allow upgrading or replacement of that equipment. BRIG also suggested that some form of financial assistance be provided to irrigators to assist them in transitioning to new tariffs. Similarly, CANEGROWERS suggested that phasing in the new tariffs over a period of three years would give those customers facing significant changes time to adjust before the full impact was felt.

Foundry operators Bundaberg Walkers and CQMS Razer highlighted the need for transitional arrangements for those customers on obsolete and declining block tariffs. Both businesses indicated that having to move from obsolete Tariff 37, which does not have a demand charge, to a new tariff with a demand charge that would apply to their high demand requirements could threaten the financial viability of their businesses.

The Australian Industry Group also raised concerns about the removal of certain existing regulated retail tariffs (such as Tariff 37) and suggested that additional time be provided to large customers to transition to negotiated market contracts.

Some retailers acknowledged the potential for customers to experience significant price increases as a result of implementing the new tariffs, but suggested that any associated social welfare concerns would be best dealt with through direct assistance from the Government rather than by continuing to distort electricity prices. As a result, retailers generally did not support transitioning customers to the new tariffs over a period of time.

The Authority's Position

As a general principle, the Authority agrees with the view put by retailers that any social welfare concerns arising from implementing the new regulated retail tariffs would be best addressed through direct assistance by the Government rather than by continuing to distort electricity prices. However, while the Government could provide financial assistance to those in need, this is not necessarily the appropriate solution for all adjustment issues customers may face. For example, the issue for commercial or farming customers adjusting their operations to the new tariff structures may be more about the time needed to make changes than about the welfare needs of the customer.

Providing some transitional relief by continuing to hold a tariff below its cost-reflective level or delaying the movement of some customers to fully cost-reflective prices would imply that either retailers continue to suffer some financial loss or higher prices continue to be applied to other customers to support on-going cross subsidies. Continuing to impose such a burden on retailers could potentially hamper competition in the Queensland retail electricity market while continuing to force other customer groups to pay higher prices would deny them the benefits of the more cost-reflective prices to which they might otherwise be entitled.

The Authority is also unable to provide transitional arrangements for large non-residential customers in Energex's network area (should they be deemed desirable), as suggested by the Australian Industry Group, as the Government has decided that these customers will no longer have access to notified prices from 1 July 2012.

Customer Impacts Expected in 2012-13

Table 6.4 shows the re-alignment of existing farming, irrigation, obsolete, declining block and street light tariffs to new network based retail tariffs for 2012-13.

Table 6.4: Alignment of Existing Regulated Retail Tariffs with New 2012-13 Regulated Retail Tariffs (and Underlying Network Tariffs)

Existing 2011-12 retail tariff	***New 2012-13 retail tariff (underlying network tariff)***
Obsolete and declining block tariffs	
Tariff 21	Tariff 20 (Energex network tariff 8500 – business, flat rate)
Tariffs 37, 62, 63 and 64	Tariff 22 (Energex network tariff 8800 – business, time-of-use)
Farming and irrigation tariffs	
Tariff 65	Tariff 22 (Energex network tariff 8800 – business, time-of-use)
Tariff 66	Tariff 41 (Energex network tariff 8300 – low voltage, demand)
Tariffs 67, 68	Tariff 20 (Energex network tariff 8500 – business, flat rate)
Street lights	
Tariff 71	Tariff 71 (Ergon Energy network tariff EVUT1 – street lighting, East price region, transmission zone 1)

Figures 6.3 and 6.4 below show the changes that customers currently on redundant tariffs can expect (on average) in their annual electricity bills when moved to the regulated retail tariffs shown in Table 6.4.

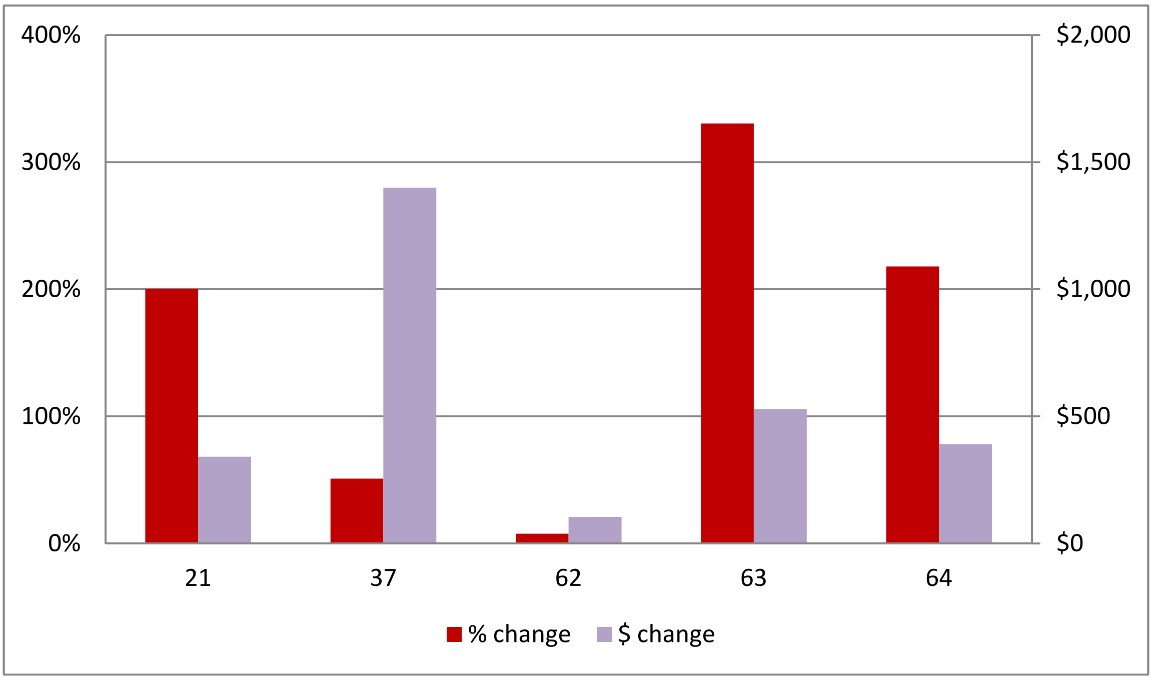
The changes shown in these figures are for levels and patterns of consumption that are typical of customers currently on each of the regulated retail tariffs shown. However, from submissions, it appears that some customers may have levels and patterns of consumption that differ significantly from the average levels assumed in this analysis and may therefore experience quite different impacts. Some of these customers may be better off moving to a different tariff rather than the one suggested in Table 6.4. The Authority does not have the customer-specific data to investigate the extent of atypical impacts or the options which may be available for some of these customers to take up alternative tariffs.

Obsolete and Declining Block Tariffs (Tariffs 21, 37, 62, 63 and 64)

Tariffs 21 and 62 are declining block tariffs. Tariffs 37, 63 and 64 are obsolete tariffs and have been so since 2007 (Tariff 37) and 1995 (Tariffs 63 and 64).

As shown in Figure 6.3, the average annual bill for customers on all obsolete and declining block tariffs is expected to increase in 2012-13 if they move to the new tariffs indicated in Table 6.4. The estimated cost increases shown in Figure 6.3 are based on typical annual consumption levels for each tariff of 300 kWh for Tariff 21, 17,600 kWh for Tariff 37, 4,840 kWh for Tariff 62, 1,220 kWh for Tariff 63 and 590 kWh for Tariff 64.

Figure 6.3: Change in Electricity Bills in 2012-13 for Customers Currently on Obsolete and Declining Block Tariffs



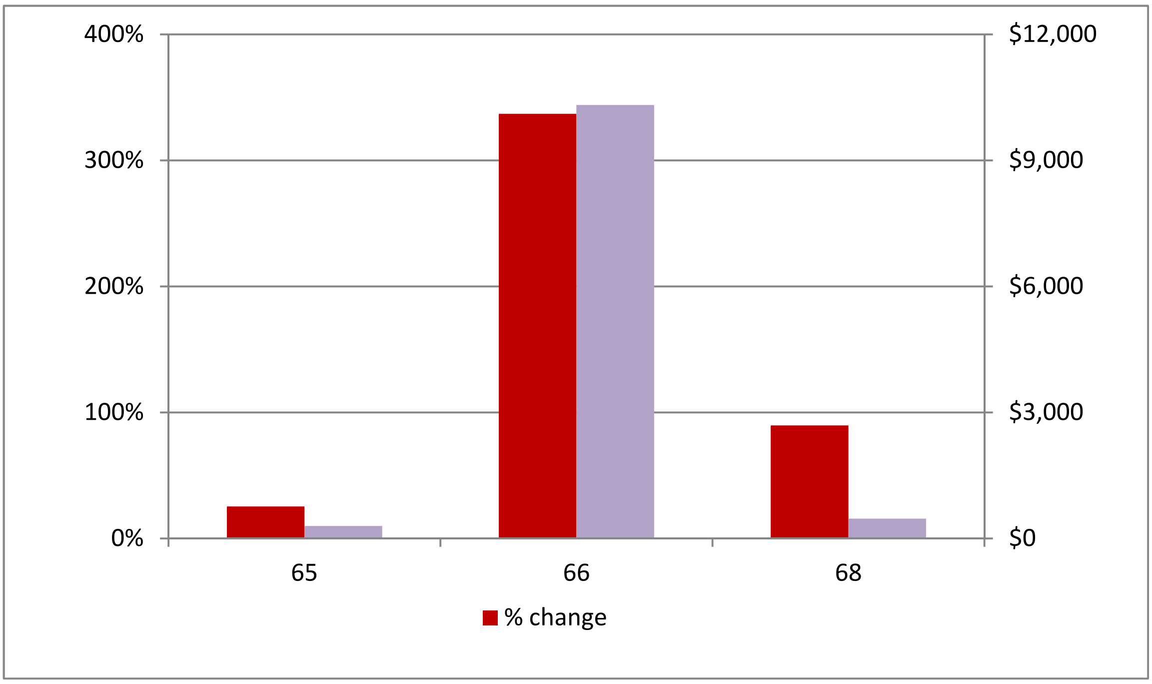
Of the declining block and obsolete tariffs, the costs for customers on Tariff 62 are expected to increase only modestly, by around $105 per annum in the move to Tariff 22. For customers on Tariffs 21, 63 and 64 the expected increases are more significant. Due to the relatively modest levels of consumption by typical customers on these tariffs, the re-balancing of prices towards higher fixed charges and lower consumption charges in 2012-13 (which has occurred generally under the new cost-reflective approach to setting notified prices) has a significant impact on the proportional bill increases expected for these customers. However, while the indicative bill increases for these tariffs are large in percentage terms, the low levels of consumption mean that the annual increase in dollar terms is more modest, at around $340 for Tariff 21, $530 for Tariff 63 and $390 for Tariff 64. On this basis, the Authority does not consider that these increases are of sufficient size to impose unmanageable impacts on affected customers.

However, customers on Tariff 37 are expected to be more affected by the move to Tariff 22 in dollar terms ($1,400 increase) than other customers in this group. This is because customers currently on Tariff 37 enjoy low off-peak charges for almost all of the standard 8am to 5pm work day whereas these hours are charged at peak rates under the replacement Tariff 22. While this is clearly an unsustainable arrangement with peak consumption being charged at off-peak rates, customers have made investments and planned businesses around these rates being available. As a result, substantial changes may be required by those customers in restructuring their business model or operations. The Authority therefore proposes to maintain Tariff 37 in its current form for 2012-13, but with 20% higher charges as a transitional step towards the higher priced replacement Tariff 22. The Authority envisages that this transitional provision would cease from 1 July 2013 when Tariff 37 would be removed from the regulated tariff schedule and remaining customers moved to Tariff 22. This arrangement provides an additional 12 months for affected customers to review their operations and power use to minimise where possible the impact of this forecast change. New customers will continue to be excluded from accessing Tariff 37.

Farming and Irrigation Tariffs (Tariffs 65, 66, 67 and 68)

As shown in Figure 6.4, customers on Tariffs 65, 66 and 68 can expect their annual bills to increase if they move to the new tariffs indicated in Table 6.4. The estimated cost changes shown in Figure 6.4 are based on typical consumption levels for each tariff of 4,790 kWh for Tariff 65, 9,910 kWh for Tariff 66, and 2,520 kWh for Tariff 68.

Figure 6.4: Change in Electricity Bills in 2012-13 for Customers Currently on Farming and Irrigation Tariffs



Customers on Tariffs 65 and 68 currently benefit from low (Tariff 65) or non-existent (Tariff 68) fixed charges. As a result of the rebalancing towards higher fixed charges that has occurred generally under the new cost-reflective approach to setting notified prices, combined with their relatively low annual consumption, these customers will (on average) experience higher electricity charges when they move to Tariffs 22 and 20 respectively.

However, as with some of the obsolete and declining block tariffs, while the percentage increase in annual bills for customers on Tariffs 65 and 68 are relatively high, the low levels of consumption by these customers means that the dollar impacts are more modest, at around $295 per annum for customers on Tariff 65 and $470 per annum for customers on Tariff 68. The Authority does not consider that these increases are of sufficient size to impose unmanageable impacts on affected customers.

However, for customers on irrigation Tariff 66 the expected increases are more significant in both percentage and dollar terms (337% or $10,320 per annum). This is mainly because these customers currently enjoy fixed charges that are much lower than those for the replacement Tariff 41. As noted in submissions, customers on Tariff 66 have planned their operations and businesses around the availability and cost of the current tariff and may have to rearrange their farming practices and use of equipment in order to reduce, where possible, the impact of these changes on their business model. The Authority therefore proposes to maintain Tariff 66 in its current form for 2012-13, but with 20% higher charges as a transitional step towards the higher priced replacement Tariff 41. The Authority envisages that this transitional provision would cease from 1 July 2013 when customers on Tariff 66 would be removed from the regulated tariff schedule and remaining customers moved to Tariff 41. This arrangement provides an additional 12 months for affected customers to review their operations and power use to minimise where possible the impact of this forecast change. No new customers will be eligible for Tariff 66.

The Authority understands that there are currently no customers on Tariff 67, which is only available to customers supplied under the Rural Subsidy Scheme. As a result, there is no need to consider transitional arrangements for this tariff.

Street Lighting Tariff (Tariff 71)

Assessing the impact of the new street lighting tariff is problematic because notified prices for street lighting currently comprise 18 different sets of fixed and variable charges depending on the type of street light and the extent to which the distributor bears the capital costs of the street lights. In addition, Ergon Energy was unable to provide any detailed data about how each of these 18 options contributed to the total amount charged for street lighting services. As a result, the Authority has not been able to ascertain whether transitional arrangements might be required for street lighting, but, regardless, would question whether such arrangements are appropriate given that any impacts will be on local councils that provide services to large groups of customers rather than individual residential or business customers.

6.3 Accounting for Unforeseen or Uncertain Events

In its Issues Paper, the Authority noted that it may be appropriate to include a mechanism to account for the impact of certain clearly defined events that lead to a material and unforeseen change in retailers' costs. While the Authority noted that such a mechanism is more commonly used by regulators setting multi-year price paths, it was of the view that there remained the possibility that, even in a single-year pricing period, there may be changes which may need to be accommodated by amending retail prices.

In past BRCI decisions, the legislative framework did not allow the Authority to include either:

(a) a cost pass-through mechanism, which would allow for price adjustments within the tariff year; or

(b) a catch up mechanism, which would account for cost impacts from a previous year in the subsequent tariff year.

As a result, retailers supplying non-market customers, at times, had to absorb any changes in costs that arose during the relevant year.

Approaches in Other Jurisdictions

In their most recent retail price determinations, all of which were multi-year determinations, IPART (NSW), the ICRC (ACT), ESCOSA (South Australia) and OTTER (Tasmania) included a cost pass-through mechanism to allow retailers to pass through to customers the incremental, efficient costs associated with defined regulatory or taxation change events.

The mechanisms adopted by all four regulators were symmetrical so that tariffs may also be adjusted downwards by the regulator to reflect any similar cost decreases. Examples of the types of events covered under these arrangements included changed obligations in relation to green energy schemes, unforeseen events instigated by AEMO (such as a reserve trader or direction event) and retailer of last resort (ROLR) events.

Submissions

In submissions received, retailers were unanimously of the view that a mechanism was required to account for the impact of unforeseen events on the R component of tariffs but acknowledged that the new legislative framework may preclude the Authority from doing so. Origin Energy, AGL and Momentum Energy suggested that, if the Authority could not include a cost pass-through mechanism, the risk of unforeseen or uncertain events occurring needed be accounted for elsewhere in the determination.

Conversely, non-retailers such as QCOSS, Queensland Farmers' Federation, Growcom and CCIQ did not support the inclusion of such a mechanism. QCOSS argued that a cost pass-through mechanism would:

(a) usually only be included where the price path is longer than a year;

(b) prevent retailers from managing risks; and

(c) be unfair to consumers.

CCIQ was of the view that the risk of unforeseen events occurring had already been accounted for in the retail margin.

The Authority's Position

While the Delegation requires that the Authority must consider a mechanism to address any new compulsory scheme that imposes material energy cost imposts on the retailer and the Authority considers that it would be appropriate to include some form of mechanism to account for the material impacts of unforeseen or uncertain events on a retailer's costs, the Authority does not consider that it has the capacity to include any such arrangements in its price determination for 2012-13.

This is because the Authority has only been delegated the role of determining notified prices to apply from 1 July 2012 to 30 June 2013, which it is required to do by 31 May 2012, and it has no on-going role in administering the price determination.

The Authority is also of the view that, given the current annual nature of the Delegation and price setting process, it would not be possible for it to commit to some form of catch-up mechanism which would allow for unforeseen cost impacts from one year to be accounted for in setting prices for the following tariff year, because:

(a) the Authority has only been delegated the function of setting notified prices for the 2012-13 tariff year, not the 2013-14 tariff year; and

(b) the Minister could decide not to delegate the function of setting notified prices in the following tariff year to the Authority, thus making any commitment worthless.

AGL and Origin Energy also suggested that the Authority should allow for some 'catch-up' of actual and forecast costs under previous BRCI decisions, particularly in relation to the ERET scheme. However, the Authority does not believe that it has any power to withdraw or amend past BRCI decisions in light of subsequent events.

The Authority's Draft Determination

The Authority is of the view that the Delegation precludes it from including a cost pass-through or catch-up mechanism in its determination of regulated retail tariffs for 2012-13.

6.4 Terms and Conditions of Retail Tariffs

The regulated retail tariffs and prices are published in a tariff schedule which includes a range of other information, including the eligibility criteria and other terms and conditions for each retail tariff.

While the Authority is responsible for determining the retail tariffs and prices, the Queensland Government (in conjunction with Energex and Ergon Energy) is responsible for determining the associated eligibility criteria and other terms and conditions.

The Minister has not delegated to the Authority the determination of charges or fees relating to customer retail services covered under section 90(1)(b) of the Electricity Act, which includes charges for the provision of historical billing information and dishonoured payments. For the purposes of the Draft Determination, the scope and level of these charges will be the same as in 2011-12.

The draft terms and conditions applying to regulated retail tariffs for 2012-13 are provided in **Appendix D** for consultation purposes only and have yet to be approved by the Government.

7. DRAFT DETERMINATION

This chapter sets out the Authority's Draft Determination of regulated retail electricity prices (notified prices) to apply from 1 July 2012 to 30 June 2013, as well as expected customer impacts.

7.1 Draft Determination

The Authority's Draft Determination is that the notified prices to apply for the period 1 July 2012 to 30 June 2013 are the prices set out in Tables 7.1 to 7.4 below.

A retail entity must charge notified prices to its non-market customers. From 1 July 2012, new and existing non-residential customers in the Energex distribution area who consume over 100 MWh per annum will not be able to access notified prices and must be on a market contract.

Table 7.1: 2012-13 Regulated Retail Tariffs and Prices for Residential Customers (GST Exclusive)

Retail tariff	*Energex network tariff*	*Fixed charge c/cust/day*	*Variable rate (flat) c/kWh*	*Variable rate 1[a] c/kWh*	*Variable rate 2[b] c/kWh*	*Variable rate 3[c] c/kWh*
Tariff 11 - Residential (inclining block)	8400	78.674		17.456	25.352	29.740
Tariff 12 - Residential (time of use)	8900	78.674		17.002	21.300	34.792
Tariff 31 - Night rate (super economy)	9000		10.954			
Tariff 33 - Controlled supply (economy)	9100		15.654			

a. First 13.69 kWh per day for Tariff 11, off-peak consumption for Tariff 12

b. Next 13.69 kWh per day for Tariff 11, shoulder consumption for Tariff 12

c. Remaining kWh per day for Tariff 11, peak consumption for Tariff 12.

Table 7.2: 2012-13 Regulated Retail Tariffs and Prices for Other Small Customers and Unmetered Supplies Other Than Street Lighting (GST Exclusive)

Retail tariff	*Energex network tariff*	*Fixed charge c/cust/day*	*Demand charge $/kW/month*	*Variable rate (flat) c/kWh*	*Variable rate (off peak) c/kWh*	*Variable rate (peak) c/kWh*
Tariff 20 - Business (flat rate)	8500	110.860		19.950		
Tariff 22 - Business (time of use)	8800	110.860			18.062	20.159
Tariff 41 - Low voltage (demand)	8300	1705.714	19.703	9.811		
Tariff 91 - Unmetered	9600			15.452		
Card-operated meters (remote communities)	8400	78.674		20.157		

Table 7.3: 2012-13 Regulated Retail Tariffs and Prices for Large Customers and Street Lighting (GST Exclusive)

Retail tariff	*Ergon Energy network tariff*	*Fixed charge*	*Demand charge*	*Capacity charge*	*Variable rate (Flat)*
		c/cust/day	*$/kW/month*	*$/kW/month*	*c/kWh*
Tariff 42 - Over 100 MWh small (demand)	EDST1	791.847	30.094		9.707
Tariff 43 - Over 100 MWh medium (demand)	EDMT1	2456.733	25.867		9.707
Tariff 44 - Over 100MWh large (demand)	EDLT1	3873.790	24.790		9.707
Tariff 53 - High voltage (demand)	EDHT1	2528.319	19.855		9.665
Tariff 54 - Connection Asset Customers	EE CAC	58951.651	5.822	11.890	8.854
Tariff 55 - Individually Calculated Customers	EE ICC	273479.330	3.336	5.444	10.568
Tariff 71 - Street lighting[a]	EVUT1	26.525			16.691

a. The fixed charge for street lighting applies to each lamp, not each customer.

As discussed in Chapter 6, for transitional purposes, the Authority has retained two existing regulated retail tariffs that would otherwise have been unavailable from 1 July 2012. The Authority's Draft Determination on the notified prices that will apply to these tariffs is set out in Table 7.4 below. New customers will be excluded from accessing these tariffs from 1 July 2012 and the Authority anticipates that these two tariffs will cease to be available to existing customers from 1 July 2013.

Table 7.4: 2012-13 Transitional Regulated Retail Tariffs and Prices

Retail tariff	*Fixed charge*	*Variable rate (10:30pm-4:30pm)*	*Variable rate (4:30pm-10:30pm)*	*Variable flat*	*Capacity charge (Up to 7.5kw)*	*Capacity charge (Over 7.5kw)*
	c/cust/month	*c/kWh*	*c/kWh*	*c/kWh*	*$/kW/year*	*$/kW/year*
Tariff 37 - Non-domestic heating (time-of- use)	632.400[a]	14.796	37.008			
Tariff 66 - Irrigation	4020.000			14.856	28.812	86.628

a. This is a minimum charge per month.
Note: New customers are not eligible for these retail tariffs.

The regulated retail tariffs and notified prices will be published in a tariff schedule which includes a range of other information, including:

(a) the eligibility criteria and other terms and conditions for each regulated retail tariff; and

(b) other fees and charges that a retail entity may charge its non-market customers, including charges for the provision of historical billing data and dishonoured payments.

The draft tariff schedule for 2012-13 is provided in **Appendix D**.

7.2 Expected Customer Impacts

Providing an estimate of the impact of this Draft Determination on customers is not as simple as it was under the previous BRCI approach (which applied a single percentage increase to all existing notified prices) because this Draft Determination involves the establishment of a completely new set of cost-reflective tariffs that differ from existing tariffs in terms of both the magnitude, and sometimes the structure, of charges.

Nevertheless, it is possible to provide an indication of the likely impacts for most customers by calculating, for each tariff, how much a typical customer's annual electricity bill is likely to change.

The alignment of existing farming, irrigation, obsolete, declining block and street lighting tariffs with the new 2012-13 regulated retail tariffs, along with the expected customer impacts of moving to those new tariffs, was presented in Chapter 6. Table 7.5 shows the alignment of the remaining current regulated retail tariffs with the new 2012-13 regulated retail tariffs.

Table 7.5: Alignment of Existing Regulated Retail Tariffs with New 2012-13 Regulated Retail Tariffs

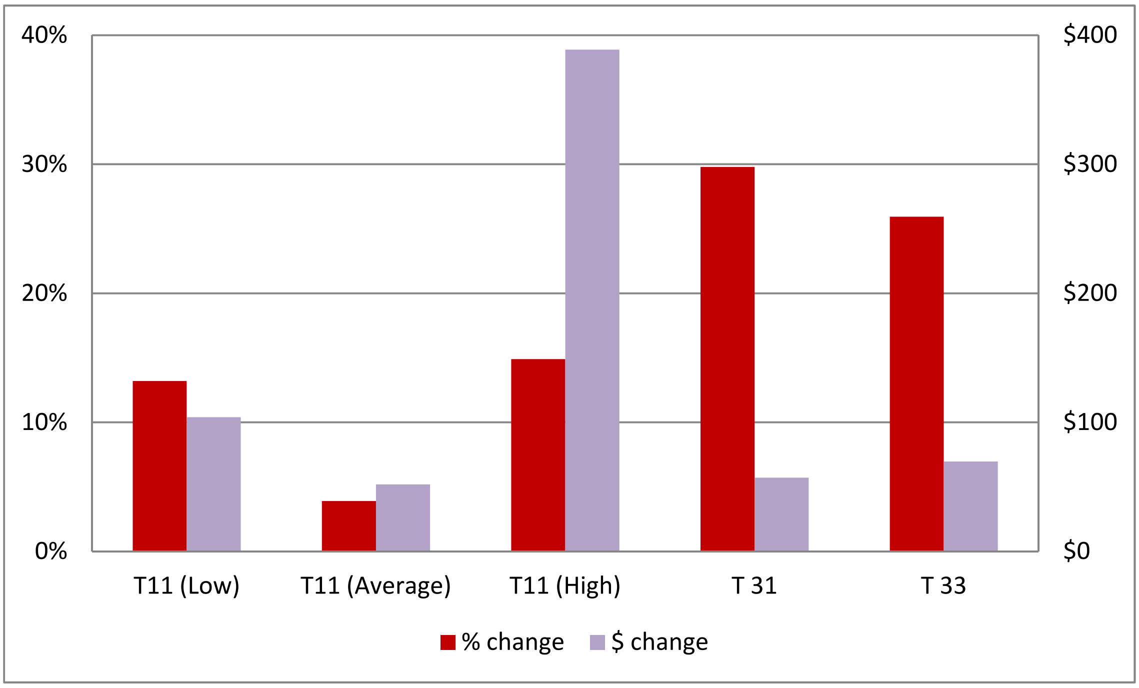
Existing 2011-12 retail tariff	*New 2012-13 retail tariff*
Residential tariffs	
Tariff 11	Tariff 11 – Residential (inclining block)
Tariff 31	Tariff 31 – Night rate (super economy)
Tariff 33	Tariff 33 – Controlled supply (economy)
Other small customer tariffs	
Tariff 20	Tariff 20 – Business (flat rate)
Tariff 22	Tariff 22 – Business (time-of-use)
Tariff 41 (<100 MWh/annum)	Tariff 41 – Low voltage (demand)
Tariff 81 and 91	**Tariff 91 – Unmetered**
Card operated meter tariff	**Card operated meter tariff**
Large customer tariffs	
Tariff 41 (>100 MWh/annum)	Tariff 42 – Over 100 MWh small (demand)
Tariff 43	Tariff 44 – Over 100 MWh large (demand)
Tariff 53	Tariff 53 – High voltage (demand)

Figures 7.1, 7.2 and 7.3 below show the changes that typical customers can expect in their annual electricity bills when moving to the new 2012-13 regulated retail tariffs. The changes

reflect a number of factors including increases in network charges to be levied by Energex and Ergon Energy, with the distributors expected to recover increased revenue for network services (DUOS and TUOS) of around 15.7% and 11.3%, and the impact of the carbon tax on the cost of energy, which will push the typical residential customer's annual bill around $140.80 (10.2%) higher than it might have been otherwise. The changes also reflect in part the removal of cross-subsidies inherent in 2011-12 notified prices, which tended to inflate notified prices for business customers and deflate notified prices for residential customers.

It is also important to note that the changes shown in these figures are for levels and patterns of consumption that are typical of customers currently on each of the regulated retail tariffs shown. From submissions, it appears likely that some customers may have levels and patterns of consumption that differ significantly from the average levels assumed in this analysis and may therefore experience quite different impacts. Some of these customers may be better off moving to a different tariff rather than the one suggested in Table 7.5. However, the Authority does not have the customer-specific data to investigate the extent of atypical impacts or the options which may be available for some of these customers to take up alternative tariffs.

Figure 7.1: Change in Electricity Bills in 2012-13 for Customers on Residential Tariffs



As shown in Figure 7.1, the annual bill for a typical customer on each of the residential tariffs is expected to increase in 2012-13. The estimated increase for a typical customer on Tariff 11 (based on average consumption in 2010-11 of 5,370 kWh) is 3.9% or $52 when moving to the new IBT. Such a customer would pay the variable rate associated with the first step of the IBT for most consumption and the variable rate for the second step of the IBT for the balance.

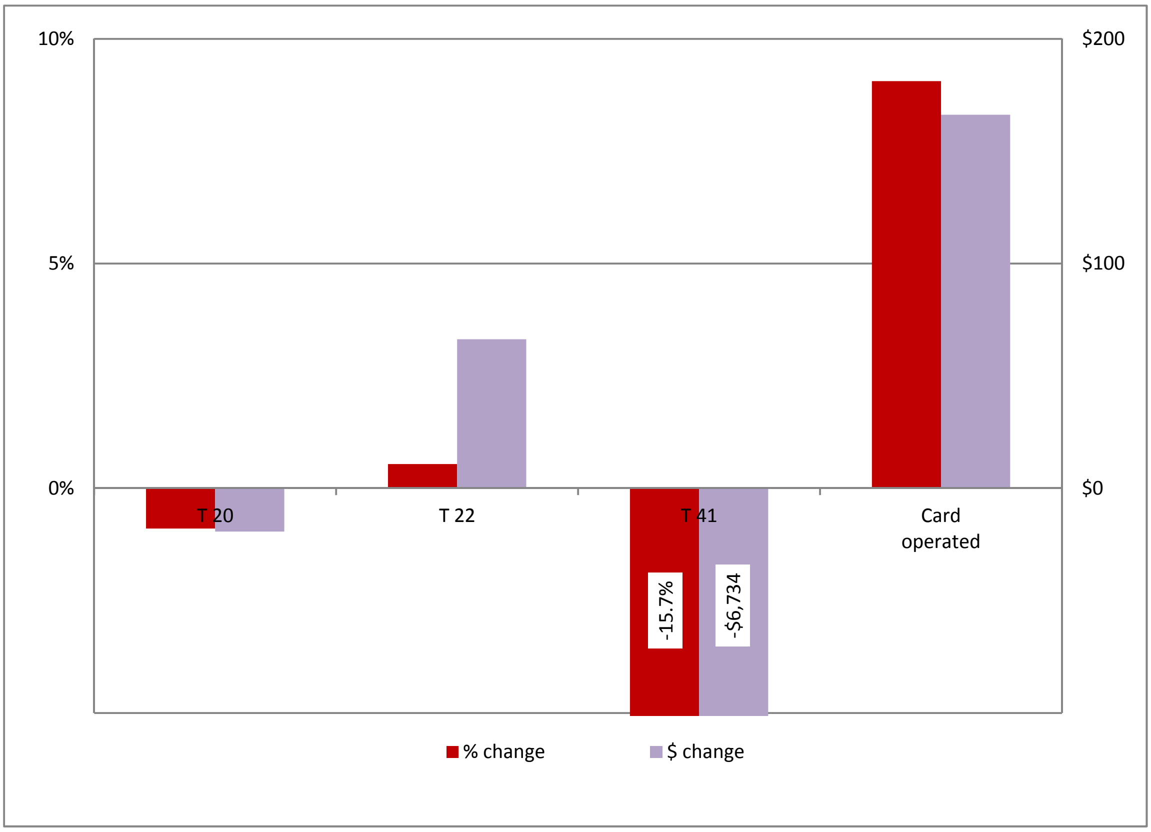
However, a Tariff 11 customer with relatively low annual consumption of 3,000 kWh would pay the variable rate associated with the first step of the IBT for all consumption and would face a bill increase of 13.2% or $104. This is due to the re-balancing of prices towards higher fixed charges and lower consumption charges in 2012-13 which will be felt more by customers on lower than average levels of consumption.

At higher than average levels of consumption, the effect of re-balancing towards higher fixed charges will be proportionately less but this will be more than off-set when the higher variable rate is charged under the IBT. For example, a customer with annual consumption of 11,000 kWh can expect a bill increase of 14.9% or $389.

Customers with higher levels of consumption may be able to reduce the impact of the above price increases associated with the IBT by instead taking up the voluntary residential time-of-use tariff (Tariff 12) and shifting their electricity consumption from the costly peak period to the less costly shoulder or off-peak periods. For example, a customer consuming 11,000 kWh per year could face an increase of only 11.6% by taking up the time-of-use tariff and shifting 10.0% of their consumption from the peak period to the off-peak period.

The estimated bill increases for Tariffs 31 and 33 (based on typical annual consumption levels of 2,066 kWh for Tariff 31 and 1,965 kWh for Tariff 33) are 29.8% (or $57) and 25.9% (or $70). These relatively large percentage increases are not due to any change in the structure of these tariffs, which remain 100% variable, but rather are a more accurate reflection of the costs of supply.

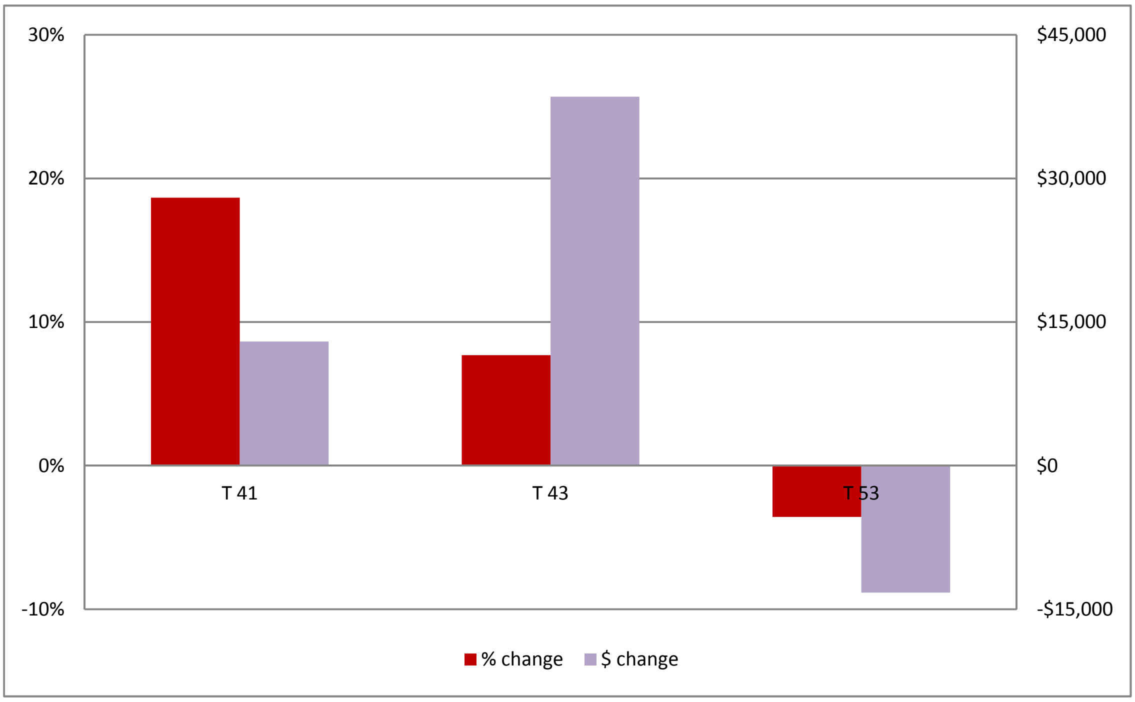
Figure 7.2: Change in Electricity Bills in 2012-13 for Small Customers on Other Tariffs



As shown in Figure 7.2, the average annual bill for a typical small customer on Tariffs 20 and 22 is expected to change only slightly, down 0.9% (or $19) for Tariff 20 and up by 0.5% (or $66) for Tariff 22. While the average annual bill for a typical small customer remaining on Tariff 41 is expected to decrease significantly by 15.7% (or $6,734), the bill for a typical customer on a card-operated meter is expected to increase by 9.1% (or $166) due to a higher fixed charge.

Unlike residential customer bills which only vary based on differences in consumption, bills for customers on business tariffs also vary due to other factors such as demand and capacity requirements. The assumptions used to estimate the above bill impacts for business customers are set out in **Appendix G**.

Figure 7.3: Change in Electricity Bills in 2012-13 for Large Customers



As shown in Figure 7.3, the average annual bill for a typical large customer is expected to decrease for those customers on Tariff 53 (by 3.6% or $13,264) but increase for those customers on Tariff 41 consuming more than 100 MWh per year (by 18.7% or $12,954) and Tariff 43 (by 7.7% or $38,530). As for business tariffs shown in Figure 7.2, the bill for typical large customers will also vary due to factors other than consumption. The assumptions used to estimate bill impacts noted above are set out in **Appendix G**.

Assessing the impact of the new unmetered supply tariff is problematic because it is to be charged per kWh of consumption whereas the existing unmetered supply tariff is charged based on the wattage of equipment supplied. The Authority does not have the data necessary to compare the cost of supply under the new tariff versus the existing tariff.

APPENDIX A: DELEGATION AND COVERING LETTER

Queensland Government

Hon Stephen Robertson MP
Member for Stretton

Minister for Energy and Water Utilities

2 2 SEP 2011

MBN5236

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

Dear Mr Parmenter

I refer to the Government's decision, in May 2011, to implement a new electricity pricing methodology based on a Network (N) + Retail (R) (N+R) cost build-up (building block) approach and establish a new set of regulated retail electricity tariffs (notified prices), to commence from 1 July 2012.

In accordance with this decision, the Electricity Price Reform Amendment Bill 2011 (the Bill) was passed by the Queensland Parliament on 7 September 2011 and received assent on 13 September 2011. The Bill contains the key legislative amendments necessary to allow for the implementation of a new electricity price-setting methodology and set of tariff structures in 2012-13.

I now attach a certificate which provides my delegation to the Queensland Competition Authority (the Authority), as the pricing entity, to determine the notified prices that retail entities may charge non-market customers in the 2012-13 tariff year. The delegation is authorised under section 90AA(1) of the Electricity Act 1994 (the Electricity Act).

The Delegation also contains a Terms of Reference which impose conditions on the Authority when undertaking the delegated function.

Consistent with the Terms of Reference, the Authority is required to undertake an open consultation process with all relevant parties and consider all submissions received within the consultation period.

The Authority must publish its draft methodology paper on the R component no later than December 2011, its draft price determination on 30 March 2012, and its final price determination by 31 May 2012.

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The Queensland Government remains concerned about the pressure that increases in the cost of living, including rising electricity costs, are placing on household budgets, and has consistently advocated in previous pricing decisions that only genuine increases in costs of supply be passed on to consumers.

With the introduction of the new price setting methodology in 2012-13, the Government wishes to again stress that the Authority must consider the impact of price rises on consumers when determining regulated prices.

It is acknowledged that a move to cost reflective tariffs will have an adverse affect on some consumers. To assist in mitigating these impacts, the Government has approved an inclining block tariff (IBT) structure for residential customers.

An IBT is designed to encourage customers to conserve electricity by charging a fixed supply charge and a series of consumption blocks priced so the more you use, the more you pay. Under this approach, the impact of moving to a cost reflective pricing structure on lower consumption customers will be lessened.

The Queensland Government will also undertake additional work to further investigate a range of customer assistance measures to further mitigate the impacts of a move to cost reflective tariffs and the increasing cost of living on small residential electricity customers. It is expected these options will be considered as part of the 2012-13 Budget process.

Delegation and Terms of Reference

In undertaking the delegated function, the Authority should consider the following:

- The network charges to be levied by ENERGEX when determining the N component of the regulated retail tariffs;
- The cost of energy component should seek to balance the long term need for maintaining pricing stability with ensuring customers are not subjected to unnecessary price volatility in the short term;
- The Government has endorsed the establishment of an IBT structure for residential customers to apply from 1 July 2012;
- The Government has endorsed the establishment of a new voluntary time-of-use tariff for residential customers from 1 July 2012;
- It is the Government's intention that any customer on an obsolete or declining block tariff will be required to move (or transition) to an alternative regulated tariff from 1 July 2012;
- Before making any changes to farming and irrigation tariffs, the Authority should consult with relevant stakeholders and industry groups and consider whether any transitional arrangements may be required;
- The Authority should consider an appropriate tariff for street lighting customers in Ergon Energy's network area and whether any transitional arrangements may be required; and
- It is the Government's intention that from 1 July 2012, all existing and new non-residential customers in ENERGEX's network area, who consume over 100 megawatt hours per annum, will be unable to access regulated tariffs and must be on a market contract.

This Delegation (and Terms of Reference) replaces the previous Direction Notice, issued to the Authority on 11 May 2011 under section 10(e) of the Queensland Competition

Authority Act 1997 (QCA Act), requiring the Authority to investigate and provide a report on:

- An alternative retail electricity pricing methodology for the determination of the cost components under an N+R approach; and
- An alternative set of retail electricity tariffs, based on an N+R approach, which could be applied from 1 July 2012.

Please be assured the process and intent reflected in the Direction Notice issued under the QCA Act will be deemed sufficient for the purposes of the price determination process for 2012-13, in accordance with section 329 of the Electricity Act.

If you have any questions about my advice to you, Ms Kathie Standen, Director, Electricity Pricing Policy of the Department of Employment, Economic Development and Innovation will be pleased to assist you and can be contacted on telephone 3225 8256.

Yours sincerely

[redacted]

STEPHEN ROBERTSON MP

ELECTRICITY ACT 1994
Section 90AA(1)

DELEGATION

As the Minister for Energy and Water Utilities, pursuant to section 90AA(1) of the *Electricity Act 1994*, I hereby refer to the Queensland Competition Authority (the Authority) the determination of regulated retail electricity tariffs (notified prices) for Queensland to apply from 1 July 2012 to 30 June 2013, in accordance with the requirements set out in the following Terms of Reference.

Terms of Reference

1. Matters to be considered

In calculating the regulated retail electricity tariffs for the relevant tariff year, the Authority should ensure its price determination has regard to:

- the actual costs of supplying electricity;
- the effect of the determination on competition in the Queensland retail electricity market, consistent with the Government's policy objective that consumers, wherever possible, have the opportunity to benefit from competition and efficiency in the marketplace;
- the Queensland Government's Uniform Tariff Policy, which ensures customers of the same class have access to uniform retail tariffs and pay the same notified price for their electricity supply, regardless of their geographic location; and
- the information contained in the Attachment.

Methodology for calculating regulated retail tariff prices

Retail electricity tariffs comprise three main cost components:

- network costs;
- energy costs; and
- retail costs.

In calculating the regulated retail tariffs for the relevant tariff year, the Authority should, to the extent possible, base its determination on a Network (N) plus Retail (R) cost build-up approach to setting notified prices, where N (network cost) is treated as a pass-through and R (energy and retail cost) is determined by the Authority.

Network Costs

In determining the network cost component of each regulated retail tariff, the Authority must consider the network charges to be levied by ENERGEX for each tariff for the relevant tariff year.

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Energy Costs

The energy cost component of each regulated retail tariff should include the cost of purchasing energy, environmental and renewable energy costs, energy losses and National Electricity Market fees.

In calculating the energy cost component, the Authority must consider:

- the cost of energy,
- fees, including charges for market and ancillary services, imposed by Australian Energy Market Operator (AEMO) under the National Electricity Rules;
- energy losses as published by the AEMO;
- the likely impact resulting from Commonwealth legislation to put a price on carbon dioxide emissions;
- the efficient costs of meeting any obligations under environmental and energy efficiency schemes (including present and future State and Commonwealth schemes); and
- a mechanism to address any new compulsory scheme that imposes material costs on the retailer.

Retail Costs

Retail costs relate to the services provided by a retailer to its customers.

In determining the retail cost component of each regulated retail tariff, the Authority must consider the retail costs that would reasonably be incurred by an efficient, representative retailer, the characteristics of which should be determined by the Authority. The Authority is also required to determine an appropriate retail margin giving consideration to any risks not compensated for elsewhere.

2. Consultation

The Authority should consult with stakeholders, conduct workshops and consider submissions, within the timetable for making the price determination and publishing the draft and final reports. The Authority must make its reports available to the public.

3. Timing

(a) Draft Methodology Paper

The Authority must publish a paper outlining its draft methodology for calculating the R component of regulated retail electricity prices no later than December 2011.

(b) Draft Price Determination

The Authority must publish a report on its draft price determination of regulated retail electricity tariffs (with each tariff to be presented as a bundled price) for the period 1 July 2012 to 30 June 2013, on 30 March 2012.

Page 2 of 4

The Authority must publish a written notice inviting submissions about the draft determination. The notice must state a period (the *consultation period*) during which anyone can make written submissions to the Authority about issues relevant to the draft determination.

The Authority must consider any submissions received within the consultation period and make them available to the public, subject to normal confidentiality considerations.

(c) Final Price Determination

The Authority must publish a report of its final price determination on regulated retail electricity tariffs (with each tariff to be presented as a bundled price) for the period 1 July 2012 to 30 June 2013, and gazette the (bundled) retail tariffs, no later than 31 May 2012.

[redacted]

The Hon. Stephen Robertson MP

Level 17 61 Mary Street, Brisbane

PO Box 15216, Brisbane
City East 4002 Australia

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Facsimile +617 3225 1828

ATTACHMENT

Determination of regulated retail electricity tariffs for the period 1 July 2012 to 30 June 2013

In making its price determination on regulated retail electricity tariffs for the period 1 July 2012 to 30 June 2013, the Queensland Competition Authority (the Authority) must have regard to the following:

- the general supply residential tariff (existing Tariff 11) is to be structured as an inclining block tariff;
- a new voluntary time-of-use tariff is to be established for residential customers;
- for farming and irrigation tariffs, targeted consultation should be undertaken with relevant stakeholders and industry groups, and consideration given to whether any transitional arrangements are needed for customers who may be required to move from one tariff to another;
- an appropriate tariff is to be established for customers who are supplied under the Rural Subsidy Scheme, or are located in a drought declared area;
- an appropriate tariff for street lighting customers in Ergon Energy's network area is to be established, and consideration given to whether any transitional arrangements are needed for customers on the existing tariff (Tariff 71); and
- consideration should be given to transitional arrangements for customers who are on obsolete and declining block tariffs.

In making its price determination, the Authority should note the following:

- From 1 July 2012, all existing and new non-residential customers in ENERGEX's network area, who consume more than 100 megawatt hours per annum, will be unable to access regulated retail electricity tariffs, and must be on a market contract;
- As at 1 July 2012, any customer who is on an obsolete or declining block tariff will be required to move to, or be transitioned to, an alternative regulated retail tariff;
- In relation to the establishment of a voluntary time-of-use tariff for residential customers, any customer who opts to transfer to this tariff, providing they have the appropriate metering, will be permitted to revert to the standard regulated tariff for residential customers in accordance with the requirements set out in the regulated retail tariff schedule.

APPENDIX B: STAKEHOLDER SUBMISSIONS

Table B.1: Submissions in Response to the Issues Paper

	Organisation/Individual
1.	AGL
2.	Alinta Energy
3.	Australian Pensioners’ and Superannuants’ League Qld
4.	Australian Power & Gas
5.	Bundaberg Regional Irrigators Group
6.	Canegrowers Australia
7.	Chamber of Commerce & Industry Queensland
8.	Council on the Ageing Queensland
9.	Donhad
10.	Electrical and Communications Association
11.	Energex
12.	Energy Supply Association of Australia
13.	Ergon Energy
14.	Origin Energy
15.	QEnergy
16.	Queensland Consumers Association
17.	Queensland Council of Social Service
18.	Tableland Canegrowers and Mareeba District Fruit and Vegetable Growers Association
19.	Alan Telfer (Individual)
20.	TRUenergy

Table B.2: Submissions in Response to the Draft Methodology Paper

Organisation/Individual
1. AGL
2. Alinta Energy
3. Australian Industry Group
4. Australian Power and Gas
5. Bundaberg Regional Irrigators Group
6. Bundaberg Walkers Engineering Ltd
7. Canegrowers Australia
8. CQMS Razer
9. Chamber of Commerce and Industry Queensland
10. Department of Employment, Economic Development and Innovation (Queensland Government)
11. Energex
12. Energy Retailers Association of Australia Ltd
13. Ergon Energy
14. Growcom (Queensland Fruit and Vegetable Growers)
15. Lumo Energy
16. Momentum Energy
17. Origin Energy
18. Power Trading Technology
19. QEnergy
20. Queensland Farmers’ Federation
21. Queensland Chicken Growers Association
22. Queensland Council of Social Service
23. Queensland Consumers Association
24. Queensland Consumers Association Supplementary
25. Stanwell
26. TRUenergy
27. Alan Telfer (Individual)
28. UBS Australia

APPENDIX C: ENERGEX'S PROPOSED (2012-13) NETWORK TARIFFS

07 July 2011

energex
positive energy

Mr Gary Henry
Director Electricity and Gas
Queensland Competition Authority
Level 19, 12 Creek Street
Brisbane QLD 4001

Dear Mr Henry

In response to your letter dated 7 June 2011, ENERGEX has completed a review of its existing network tariff schedule to align with the objectives set out in the Ministerial Direction Notice received by the Queensland Competition Authority.

Attachment 1 to this letter includes ENERGEX's proposed 2012-13 network tariff structure and a matrix illustrating how these are intended to map against the expected regulated retail tariffs. In particular, the following changes from the existing 2011-12 tariff structure should be noted:

- the introduction of a new inclining block network tariff for domestic customers which will replace the existing flat rate network tariff;
- a new voluntary domestic time of use network tariff;
- the simplification of the business non-demand network tariffs;
- the simplification of the business demand network tariffs; and
- the simplification of the un-metered supply, street lighting and watchman lights network tariffs into a single network tariff.

Where ENERGEX does not have an existing specific network tariff, such as farming and irrigation tariffs, the most appropriate network tariff has been proposed. This is the same network tariff that would be charged to customers currently on this retail tariff.

Providing customers with options which encourage demand reduction during peak times is a key part of ENERGEX's network demand management strategy. A special reward option is proposed for customers who install air-conditioners which are demand management enabled. The details of this reward option are under development, however, it is expected to be a fixed annual payment to enrolled customers based on the long run marginal cost of demand.

Enquiries
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ABN 40 078 849 055

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Attachment 2 contains ENERGEX's proposed structure of the new inclining block tariff and voluntary time of use tariff for domestic customers. This attachment also includes proposed changes to the business non-demand time of use tariff structure.

It should be noted that any changes to ENERGEX's network tariff structure must be approved by the Australian Energy Regulator (AER) and therefore should only be considered draft at this stage.

Yours Sincerely

[redacted]

Kevin Kehl
Executive General Manager Strategy & Regulation
ENERGEX Limited

Attachment 1

Tariff Mapping – Network Tariffs v Proposed Notified Tariffs

2012-13 Tariff Mapping				Notified Tariffs – Queensland Gazette																
				T11 Existing	T20 Existing	T22 Existing	T31 Existing	T33 Existing	T41 Existing	T43 Existing	T53 Existing	T71 Existing	T81 Existing	T91 Existing	T11 (A) New	T62 Existing	T65 Existing	T66 Existing	T67 Existing	T68 Existing
	NTC	**Description**	**Approx current cust. numbers**	*IBT – Domestic*	*Flat – Business*	*TOU – Business* *(Times to be reviewed)*	*Flat – Controlled Load 1*	*Flat – Controlled Load 2*	*Demand – min 75kW*	*Demand – min 400kW*	*Demand – HV*	*Public Lamps*	*Flat – Unmetered* *(Rename Required)*	*Watchman Lights*	*TOU – Domestic*	*TOU – Farm*	*TOU – Irrigation*	*Flat/ Demand – Irrigation*	*Flat – Farm*	*Flat – Irrigation Drought Area*
ENERGEX Network Tariffs	**8400**	*IBT – Domestic*	*1,227,588*	✓																
	8450 New	*TOU – Domestic*	*n/a – proposed tariff*												✓					
	8500 **8600**	*Flat – Small Business* *Flat – Medium Business* ***Combined into one tariff***	*73,932 (Small)* *19,422 (Medium)*		✓														✓	✓
	8700 **8800**	*TOU – Small Business* *TOU – Medium Business* *(Times to be reviewed)* ***Combined into one tariff***	*7,265 (Small)* *8,278 (Medium)*			✓										✓	✓			
	9000	*Flat – Controlled Load 1*	*216,000*				✓													
	9100	*Flat – Controlled Load 2*	*511,000*					✓												
	9600	*Flat – Unmetered*	*n/a – volume charge only*									✓	✓	✓						
	8300	*Demand – small*	*4,795*						✓									✓		
	8100	*Demand – large*	*403*							✓										
	8000	*HV Demand*	*29*								✓									

Obsolete Retail Tariffs

Notified Tariff	Description
Tariff 21	*Declining Block Tariff – Business*
Tariff 37	*TOU – Non – domestic heating*
Tariff 63	*TOU – Farm*
Tariff 64	*TOU – Irrigation*

Other ENERGEX Network Tariffs

NTC	Description	Approx current cust. numbers	Proposal for 2012-13
9400	*Flat – Streetlights*	*n/a – volume charge only*	Network tariff to be removed – all unmetered supply is to be mapped to NTC 9600.
9500	*Flat – Watchman lights*	*n/a – volume charge only*	Network tariff to be removed – all unmetered supply is to be mapped to NTC 9600.
8200	*Demand – medium*	3,041	Network tariff to be removed – all existing customers transferred to Demand Small or Demand Large
Site specific	*Demand/Capacity – Large Customers*	488	Designed for customers > 4 GWh – ENERGEX network tariff only, not available in the gazette

Attachment 2

Proposed Tariff Structure

1. Proposed structure for the domestic inclining block tariff:

   Fixed Service Charge (c/day)
   \+
   Consumption charge (c/kWh) based on the following inclining block structure:

   Block 1 - 0 - 5000 (kWh per annum)
   Block 2 - 5001 - 10000 (kWh per annum)
   Block 3 - 10,001 + (kWh per annum)

   Note: we anticipate the above would be billed on a pro-rata basis

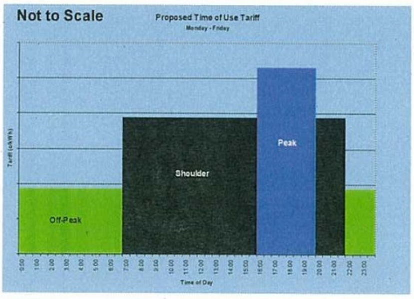
2. Proposed structure for the domestic time of use:

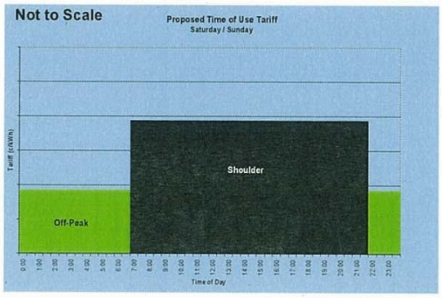
   Fixed Service Charge (c/day)
   \+
   Consumption charge (c/kWh) based on the following time of use structure:

   Monday to Friday
   - Off peak 10pm – 7am
   - Shoulder 7am – 4pm, 8pm – 10pm
   - Peak 4pm - 8pm

   Saturday/Sunday
   - Off peak 10pm – 7am
   - Shoulder 7am - 10pm
   - No Peak

   The proposed structure is illustrated below:





3. Proposed changes to the times associated with business non-demand time of use: .

   Fixed Service Charge (c/day)
   \+
   Consumption charge (c/kWh) based on the following time of use structure:

   - Off peak 9pm – 7am
   - Shoulder 7am – 12pm
   - Peak 12pm – 9pm

APPENDIX D: DRAFT TARIFF SCHEDULE FOR 2012-13

Queensland Government Gazette

RETAIL ELECTRICITY PRICES FOR NON-MARKET CUSTOMERS

Electricity Act 1994

Pursuant to the Certificate of Delegation from the Minister for Energy and Water Utilities (dated 22 September 2011) and sections 90(2) and 90AB of the *Electricity Act 1994* (the Electricity Act), I hereby state that the Queensland Competition Authority decided that, on and from 1 July 2012, the notified prices that a retail entity must charge its customers on a Standard Retail Contract or Standard Large Customer Retail Contract (also referred to as a Standard Retail Contract), subject to the provisions of sections 55, 90, 91 and 91A of the Electricity Act, are the applicable prices set out in the attached Tariff Schedule or, as the case may be, the prices obtained by applying the applicable methodology or process set out in the attached Tariff Schedule.

This Tariff Schedule does not apply to customers on a Standard Retail Contract supplied under Origin Energy Electricity Limited's Special Approval number SA02/11 (being customers on a Standard Retail Contract connected to Essential Energy's New South Wales network which extends into southern Queensland). Under the terms of the Special Approval, these customers will generally pay no more for electricity than other Queensland customers on a Standard Retail Contract of similar usage categories or classes.

The Tariff Schedule does not apply to customers in the ENERGEX Limited's distribution area who consume over 100 megawatt hours (MWh) per annum, unless the customer is classified as residential. From 1 July 2012, non-residential customers in the ENERGEX distribution area who consume over 100 MWh per annum will not have access to notified prices.

As required by section 90AB(4) of the Electricity Act, I state that the notified prices are exclusive of the goods and services tax ('GST') payable under the *A New Tax System (Goods and Services Tax) Act 1999* (Cth) ('the GST Act').

In addition to the applicable tariff, a retail entity may charge a customer on a Standard Retail Contract an additional amount in accordance with a program or scheme for the purchase of electricity from renewable or environmentally-friendly sources (whether or not that additional amount is calculated on the basis of the customer's electricity consumption), but only if –

(a) the customer voluntarily participates in such program or scheme;

(b) the retail entity has obtained the customer's consent (as defined in the Electricity Industry Code) to charge the customer an additional amount (and whether such amount is inclusive or exclusive of GST), provided that if a customer is participating in such a program or scheme at 30 June 2007 the customer is taken to have provided explicit informed consent for the retail entity to charge the customer the additional amount payable under the program or scheme; and

(c) the retail entity gives the customer prior written notice of any change to the additional amount payable under the program or scheme.

Dated this xx day of May 2012.

Brian Parmenter, Chairman
Queensland Competition Authority

QUEENSLAND GOVERNMENT GAZETTE No. xx [xx May 2012]

TARIFF SCHEDULE

Note 1: For the purposes of sections 55, 90, 91 and 91A of the Electricity Act, the tariffs and other retail fees and charges in this Tariff Schedule are exclusive of GST payable under the GST Act.

Note 2: This Tariff Schedule is structured in several Parts:

Parts 1 to 4 (inclusive) apply to customers on a Standard Retail Contract;

Part 5 applies to eligible customers on a Standard Retail Contract of Ergon Energy Queensland Pty Ltd. Eligible customers on a Standard Retail Contract of other retail entities may apply directly to the Department of Employment, Economic Development and Innovation for relief from electricity charges if a drought declaration is in force – see Part 5 for more detail.

Note 3: To ensure the correct application of the tariffs set out in this Tariff Schedule, the retail entity and the customer must have regard to Part 3 (Application of Tariffs for Customers on Notified Prices – General).

Note 4: Any reference in this Tariff Schedule to a time is a reference to Eastern Standard Time.

Note 5: "NMI" means the National Metering Identifier and is applicable to the point at which a premises is connected to a distribution entity's network.

Part 1

TARIFFS FOR RESIDENTIAL, COMMERCIAL AND RURAL APPLICATIONS

***Tariff 11* – Residential (Lighting, Power and Continuous Water Heating) (Inclining Block) –**

This tariff is applicable to a customer who is classified as residential by the relevant retail entity.

This tariff is also applicable to electricity used in separately metered common sections of residential premises consisting of more than one flat or home unit.

This tariff cannot be used in conjunction with Tariff 12 (Residential) (Time of Use) at the same NMI.

Where a NMI has multiple meters, the consumption for all Tariff 11 meters will be aggregated for billing purposes.

This tariff can be accessed by a small business customer providing it is in conjunction with a primary business tariff (Tariff 20, 22 or 41) at the same NMI.

No new large business customers are eligible for this tariff.

All consumption

A Service Fee per metering point per day of **78.674 c**

plus

Average daily consumption thresholds per billing period -

Block 1	**First 13.69 kWh/day**	**17.456 c/kWh**
Block 2	**Next 13.69 kWh/day**	**25.352 c/kWh**
Block 3	**Remaining kWh/day**	**29.740 c/kWh**

For more detailed billing information, refer to Part 3 (Application of Tariffs for Customers on Notified Prices – General).

Further applications of this tariff are described in Part 3 (Application of Tariffs for Customers on Notified Prices – General) and Part 4 (Concessional Applications of Tariffs 11 and 12 (Residential)).

***Tariff 12* – Residential (Lighting, Power and Continuous Water Heating) (Time-of-Use) –**

This tariff is applicable to a customer who is classified as residential by the relevant retail entity.

This tariff is available to all residential customers on a voluntary basis.

This tariff is also applicable to electricity used in separately metered common sections of residential premises consisting of more than one flat or home unit.

This tariff cannot be used in conjunction with Tariff 11 (Residential) (Inclining Block) at the same NMI.

Where a NMI has multiple meters, the consumption for all Tariff 12 meters will be aggregated for billing purposes.

This tariff can be accessed by a small business customer providing it is in conjunction with a primary business tariff (Tariff 20, 22 or 41) at the same NMI.

No large business customers are eligible for this tariff.

Customers must have the appropriate metering installed in order to access this tariff.

All consumption

Weekdays:	
Off-Peak (10pm-7am)	**17.002 c/kWh**
Shoulder (7am-4pm), (8pm-10pm)	**21.300 c/kWh**
Peak (4pm-8pm)	**34.792 c/kWh**
Weekends:	
Off-Peak (10pm-7am)	**17.002 c/kWh**
Shoulder (7am-10pm)	**21.300 c/kWh**

plus a Service Fee per metering point per day of **78.674 c**

***Tariff 20* – Business General Supply –**

This tariff can not be accessed by large business customers.

Residential customers can access this tariff providing it is in conjunction with a residential tariff at the same NMI.

All Consumption **19.950 c/kWh**

plus a Service Fee per metering point per day of **110.860 c**

***Tariff 22* – Business General Supply – Time-of-Use–**

This tariff can not be accessed by large business customers.

Residential customers can access this tariff providing it is in conjunction with a residential tariff at the same NMI.

Customers must have the appropriate metering installed in order to access this tariff.

For electricity consumed between the hours of 7.00 am and 9.00 pm, Monday to Friday inclusive -

All Consumption **20.159 c/kWh**

For electricity consumed at other times -

All Consumption **18.062 c/kWh**

plus a Service Fee per metering point per day of **110.860 c**

***Tariff 31* – Night Rate (Super Economy) –**

Customers can access this tariff providing it is in conjunction with a residential or business tariff at the same NMI.

This tariff is applicable when electricity supply is:

- permanently connected to apparatus; or
- connected to apparatus by means of a socket-outlet as approved by the distribution entity; or
- permanently connected to specified parts of apparatus as set out below (but not applicable, except as described in (c) below, if provision has been made to supply such apparatus or the specified part thereof under a different tariff during the restricted period) -

(a) Electric storage water heaters with thermostatically controlled or continuously operating heating units and which comply with the construction and performance requirements of Australian Standard 1361 or 1056 or previous Standards superseded by these two Standards or similar electric water heaters which are approved for connection by the distribution entity.

Where the heating unit rating exceeds 1,800 watts, it shall not exceed 13.5 watts per litre of heat storage volume for heat exchange type water heaters or 15.5 watts per litre of rated hot water delivery for other storage type water heaters.

The following conditions shall apply to any booster heating unit fitted -

(i) its rating shall not exceed that of the main heating unit;

(ii) it shall be connected so as to prevent its being energised simultaneously with the main heating unit;

(iii) electricity consumed by the booster heating unit shall be metered under and charged at the tariff applicable to general power usage at the premises concerned;

(iv) it shall be located in accordance with the provisions of the above Standards.

(b) Solar-heated water heaters. Where the electric heating unit rating exceeds 1,800 watts, it shall not exceed 13.5 watts per litre of storage tank capacity. If a circulating water pump is fitted to the system, continuous supply will be available to the pump, and electricity consumed shall be metered under and charged at the tariff applicable to general power usage at the premises concerned.

(c) One-shot boost for solar-heated water heaters with electric heating units as described in (b) above. A current held changeover relay may be fitted to the water heater to deliver, at the customer's convenience, a 'one-shot boost' supply to the electric heating element at times when supply is not available under this Tariff 31 (generally between the hours of 7.00 am and 10.00 pm). Such supply is subject to thermostatically controlled switchoff. Electricity consumed during operation of the one-shot boost shall be metered under and charged at the tariff applicable to general power usage at the premises concerned. Supply and installation of a current held changeover relay, including the cost of same, is the responsibility of the customer.

(Reference in this Tariff Schedule to a 'booster heating unit' does not mean a current held changeover relay which is capable of delivering a 'one-shot boost'.)

(d) Heatpump water heaters. Where the rated electrical input, as shown on the nameplate, exceeds 1,800 watts, it shall not exceed 13.5 watts per litre of storage tank capacity.

(e) Heatbanks. Booster heating units are permitted in heatbanks in which the main element rating is at least 2 kilowatts. The following conditions shall apply to any booster heating unit fitted –

(i) its rating shall not exceed 70 percent of the rating of the main heating unit;

(ii) it shall be connected so as to prevent its being energised simultaneously with the main heating unit;

(iii) electricity consumed by the booster heating unit shall be metered under and charged at the tariff applicable to general power usage at the premises concerned.

(f) Loads other than water heaters and heatbanks, but is not applicable -

(i) to arc or resistance welding plant;

(ii) where the apparatus is duplicated in order that supply may be obtained on a different tariff for the same purpose during the restricted period.

Connections to this tariff may also be agreed to by the distribution entity.

The distribution entity will provide and install the load control equipment at its cost. Additional charges may apply for other distribution services associated with the load control equipment, where the costs of the requested service are not included in the distribution entity's network charges.

Supply will be available for a minimum of 8 hours per day, but the times when supply is available is subject to variation at the absolute discretion of the distribution entity. In general, this supply will be between the hours of 10.00 pm and 7.00 am.

All Consumption **10.954 c/kWh**

***Tariff 33* – Controlled Supply (Economy) –**

Customers can access this tariff providing it is in conjunction with a residential or business tariff at the same NMI.

This tariff is applicable when electricity supply is:

(a) connected to apparatus (e.g. pool filtration system) by means of a socket-outlet as approved by the distribution entity; or

(b) permanently connected to apparatus as set out below (but not applicable if provision has been made to supply such apparatus under a different tariff in the periods during which supply is not available under this tariff) –

(i) Electric storage water heaters with thermostatically controlled or continuously operating heating units and which comply with the construction and performance requirements of Australian Standard 1361 or 1056 or previous Standards superseded by these two Standards or similar electric water heaters which are approved for connection by the distribution entity.

Where the heating unit rating exceeds 1,800 watts, it shall not exceed 13.5 watts per litre of heat storage volume for heat exchange type water heaters or 15.5 watts per litre of rated hot water delivery for other storage type water heaters.

(ii) Solar-heated water heaters. Where the electric heating unit rating exceeds 1,800 watts, it shall not exceed 13.5 watts per litre of storage tank capacity.

(iii) Heatpump water heaters. Where the rated electrical input, as shown on the nameplate, exceeds 1,800 watts, it shall not exceed 13.5 watts per litre of storage tank capacity.

(iv) As a sole supply tariff for domestic installations, as approved by the distribution entity, where photovoltaic cell/ battery bank/inverter apparatus is used to provide a supplementary supply to the interruptible supply provided by this tariff.

(v) Other individual loads in domestic installations, but is not applicable –

- to arc or resistance welding plant;
- where the apparatus is duplicated in order that supply may be obtained on a different tariff for the same purpose during the restricted period.

Connections to this tariff may also be agreed to by the distribution entity.

The distribution entity will provide and install the load control equipment at its cost. Additional charges may apply for other distribution services associated with the load control equipment, where the costs of the requested service are not included in the distribution entity's network charges.

Supply will be available for a minimum of 18 hours per day, but the times when supply is available is subject to variation at the absolute discretion of the distribution entity.

All Consumption **15.654 c/kWh**

***Tariff 37* – Non-Domestic Heating – Time-of-Use (Obsolescent) –**

This tariff will be retained for 2012-13 only. No new customers will be supplied under this tariff. It is available only to customers taking supply under Tariff 37 at 30 June 2007.

Applicable to permanently connected –

(a) Electric storage water heaters in non-domestic installations with thermostatically controlled or continuously operating heating units and which comply with the construction and performance requirements of Australian Standard 1361 or 1056 or previous Standards superseded by these two Standards or similar electric water heaters which are approved for connection by the distribution entity.

The heating unit rating shall not exceed 40.5 watts per litre of heat storage volume for heat exchange type water heaters or 46.5 watts per litre of rated hot water delivery for other storage type water heaters.

(b) Apparatus for the production of steam.

(c) Heating loads other than (a) and (b) above. The minimum total connected load under this section of this tariff is 4 kilowatts. Supplementary load that is permanently connected as an integral part of the installation may be supplied under this section provided that the aggregated rating of such supplementary load does not exceed 10 percent of the heating load.

For electricity consumed between the hours of 4.30 pm and 10.30 pm **37.008 c/kWh**

For electricity consumed between the hours of 10.30 pm and 4.30 pm **14.796 c/kWh**

Minimum Payment per month of **632.4 c**

***Tariff 41* – Business Low Voltage General Supply (Demand) –**

This tariff can not be accessed by large business customers.

Demand Charge –

$19.703 per kilowatt of chargeable demand per month.

Energy Charge –

All Consumption **9.811 c/kWh**

plus a Service Fee per metering point per day of **1705.714 c**

The chargeable demand in any month shall be the maximum demand recorded in that month.

'Demand' shall mean the average demand in kilowatts over a period of 30 minutes, as measured on the distribution entity's meters.

Customers must have the appropriate metering installed in order to access this tariff.

***Tariff 42* – Business Over 100MWh (Demand Small) –**

This tariff can be accessed by business customers classified as SAC >100MWh per annum by the distribution entity. The tariff is based on Ergon Energy Corporation Limited network tariff of Demand Small.

A Standard Asset Customer (SAC) is a large business customer in Ergon Energy Corporation Limited's distribution area whose annual energy consumption generally exceeds 100MWh.

Demand Charge –

$30.094 per month per kilowatt of chargeable demand.

Energy Charge –

All Consumption **9.707 c/kWh**

plus a Service Fee per metering point per day of **791.847 c**

The chargeable demand in any month shall be the maximum demand recorded in that month with a minimum chargeable demand of 30kW to apply.

'Demand' shall mean the average demand in kilowatts over a period of 30 minutes, as measured on the distribution entity's meters.

Customers must have the appropriate metering installed in order to access this tariff.

***Tariff 43* – Business Over 100MWh (Demand Medium) –**

This tariff can be accessed by business customers classified as SAC >100MWh per annum by the distribution entity. The tariff is based on the Ergon Energy Corporation Limited network tariff of Demand Medium.

A Standard Asset Customer (SAC) is a large business customer in Ergon Energy Corporation Limited's distribution area whose annual energy consumption generally exceeds 100MWh.

Demand Charge –

$25.867 per month per kilowatt of chargeable demand.

Energy Charge –

All Consumption **9.707 c/kWh**

plus a Service Fee per metering point per day of **2456.733 c**

The chargeable demand in any month shall be the maximum demand recorded in that month with a minimum chargeable demand of 120kW to apply.

'Demand' shall mean the average demand in kilowatts over a period of 30 minutes, as measured on the distribution entity's meters.

Customers must have the appropriate metering installed in order to access this tariff.

***Tariff 44* – Business Over 100MWh (Demand Large) –**

This tariff can be accessed by business customers classified as SAC >100MWh per annum by the distribution entity. The tariff is based on the Ergon

Energy Corporation Limited network tariff of Demand Large.

A Standard Asset Customer (SAC) is a large business customer in Ergon Energy Corporation Limited's distribution area whose annual energy consumption generally exceeds 100MWh.

Demand Charge –

$24.790 per month per kilowatt of chargeable demand.

Energy Charge –

All Consumption **9.707 c/kWh**

plus a Service Fee per metering point per day of **3873.790 c**

The chargeable demand in any month shall be the maximum demand recorded in that month with a minimum chargeable demand of 400kW.

'Demand' shall mean the average demand in kilowatts over a period of 30 minutes, as measured on the distribution entity's meters.

Customers must have the appropriate metering installed in order to access this tariff.

Tariff 53 **– Business - High Voltage General Supply (Demand) –**

This tariff can be accessed by business customers classified as SAC >100MWh per annum by the distribution entity. The tariff is based on the Ergon Energy Corporation Limited network tariff of Demand High Voltage.

Demand Charge –

$19.855 per month per kilowatt of chargeable demand.

Energy Charge –

All Consumption **9.665 c/kWh**

plus a Service Fee per metering point per day **2528.319 c**

The chargeable demand in any month shall be the maximum demand recorded in that month with a minimum chargeable demand of 400kW.

'Demand' shall mean the average demand in kilowatts over a period of 30 minutes, as measured on the distribution entity's meters. Supply under this tariff will be at a standard high voltage, the level of which shall be prescribed by the distribution entity. Credits for high voltage supply are not applicable to this tariff.

Customers must have the appropriate metering installed in order to access this tariff.

Tariff 54 **– Connection Asset Customers –**

This tariff can be accessed by business customers who are classified as Connection Asset Customers by the distribution entity.

A Connection Asset Customer is a large business customer in Ergon Energy Corporation Limited's distribution area whose annual energy consumption generally exceeds 4GWh.

Demand Charges –

1. Capacity Charge -

$12.335 per kilowatt of Authorised Demand per month.

2. Actual Demand Charge -

$5.805 per kilowatt of chargeable demand per month

Energy Charge –

All Consumption **8.962 c/kWh**

plus a Service Fee per metering point per day of **58385.072 c**

Authorised Demand is as specified by the distribution entity. The chargeable demand in any month shall be the maximum demand recorded in that month. Where the chargeable demand exceeds the Authorised Demand in any one month the chargeable demand will be substituted for the Authorised Demand in the calculation of the capacity charge for that month.

'Demand' shall mean the average demand in kilowatts over a period of 30 minutes, as measured on the distribution entity's meters.

Tariff 55 **– Individually Calculated Customers –**

This tariff can be accessed by business customers who are classified as Individually Calculated Customers by the distribution entity.

An Individually Calculated Customer is a large business customer in Ergon Energy Corporation Limited's distribution area whose annual energy consumption generally exceeds 40GWh.

Demand Charges –

1. Capacity Charge -

$5.444 per kilowatt of Authorised Demand per month.

2. Actual Demand Charge -

$3.336 per kilowatt of chargeable demand per month

Energy Charge –

All Consumption **10.568 c/kWh**

plus a Service Fee per metering point per day of **273479.330 c**

Authorised Demand is as specified by the distribution entity. The chargeable demand in any month shall be the maximum demand recorded in that month. Where the chargeable demand exceeds the Authorised Demand in any one month the chargeable demand will be substituted for the Authorised Demand in the calculation of the capacity charge for that month.

'Demand' shall mean the average demand in kilowatts over a period of 30 minutes, as measured on the distribution entity's meters.

***Tariff 66* – Irrigation – (Obsolescent) –**

This tariff will be retained for 2012-13 only. No new customers will be supplied under this tariff.

Annual Fixed Charge (in respect of each point of supply) - per kilowatt of connected motor capacity used for irrigation pumping –

First 7.5 kilowatts $**28.812** per kW

Remaining kilowatts $**86.628** per kW

Energy Charge –

All Consumption **14.856 c/kWh**

plus a Service Fee per metering point per month of **4020.000 c**

Minimum Annual Fixed Charge - As calculated for 7.5 kW (Note – 7.5 kW is equivalent to 10.05 h.p.).

Any customer taking supply under this tariff who requests a temporary disconnection will not be reconnected unless the outstanding balance of the Annual Fixed Charge for part of the year corresponding to the period of disconnection has been paid.

Part 2

TARIFFS FOR UNMETERED SUPPLY INCLUDING STREET LIGHTS, TRAFFIC SIGNALS, WATCHMAN LIGHTING AND TEMPORARY SERVICES

***Tariff 71* – Street Lights –**

Notified prices for Tariff 71, published in accordance with section 90 of the Electricity Act, will only apply in Ergon Energy Corporation Limited's distribution area. The *Electricity Regulation Amendment (No.1) 2008* provides that, from 1 July 2008, street lighting customers in Energex Limited's distribution area will be defined as market customers and so will not be subject to the notified prices.

All consumption will be determined in accordance with the metrology procedure issued by the Australian Energy Market Operator.

Where a distribution entity has assumed ownership and is responsible for maintaining a street lighting installation, the additional amounts will be billed to the street lighting customer's chosen retail entity for inclusion on the customer's bill. The distribution entity may also elect to bill the customer directly for distribution charges at its absolute discretion.

All Consumption **16.691 c/kWh**

plus a Service Fee per lamp per day of **26.525 c**

***Tariff 91* - Other Unmetered Supply**

Unmetered electricity supply is available to other small loads, as approved by the distribution entity.

Unmetered Supply applies where:

1. the load pattern is predictable;
2. for the purposes of *settlements*, the load pattern can be reasonably calculated by a relevant method set out in the *metrology procedure*; and
3. it would not be cost effective to meter the *connection point* taking into account:
   (i) the small magnitude of the *load*;
   (ii) the *connection* arrangements; and
   (iii) the geographical and physical location.

Charges are based on consumption determined by the distribution entity.

Charges for installation, maintenance and removal of supply to an unmetered installation may apply in addition to the above charge for electricity supplied.

All Consumption **15.542 c/kWh**

Part 3

APPLICATION OF TARIFFS FOR CUSTOMERS ON NOTIFIED PRICES – GENERAL

Customers on a Standard Retail Contract may choose to be charged on any of the tariffs that the retail entity agrees are applicable to the customer's installation and provided that appropriate metering is in place.

Tariffs are applied to the electricity consumed at a connection point (as identified by a National Metering Identifier or NMI), as measured by the meter or meters at that connection point. The distribution entity is responsible for the establishment of connection points. Whilst customers have the ability to, at their expense if applicable, request additional meters at their connection point to enable particular tariff arrangements, the distribution entity will only create a new connection point where they have a legislative right or obligation to do so.

If there has been a material change of use at the customer's premises, such that the tariff on which the customer is being charged is no longer applicable, the retail entity may require the customer to transfer to a tariff applicable to the changed use.

If a change to the customer's meter is required to support the applicability of a tariff, other than Tariff 12, to a customer, the customer may request the retail entity to arrange for the required meter to be installed at the customer's cost.

For all tariffs, excluding Tariff 11 and Tariff 12, customers have the option, on application in writing or another form acceptable to the retail entity, of changing to any other tariff that the retail entity agrees is applicable to the customer's installation. Customers shall not be entitled to a further option of changing to another tariff until a period of twelve months has elapsed from a previous exercise of option. However, a retail entity at the request of a customer may permit a change to another tariff within a period of twelve months if –

(i) a tariff that was not previously in force is offered and such tariff is applicable to the customer's installation; or

(ii) the customer meets certain costs associated with changing to another tariff.

Customers previously supplied under tariffs which have now been discontinued or redesignated (whether by number, letter or name) will be supplied under other tariffs appropriate to their installations.

Large business customers with access to notified prices who are currently on Tariff 20 or 22 will be transferred to the appropriate tariff (Tariff 42, 43, 44, 53, 54 or 55).

Residential customers will have the option, from 1 July 2012, on application in writing or another form acceptable to the retail entity, of switching from Tariff 11 to Tariff 12, provided they have the appropriate metering installed. Prior to 30 June 2013, customers will also be entitled to a further option of switching back to Tariff 11. Additional charges may also apply should a customer wish to switch tariffs again prior to 30 June 2013.

The date of effect of a tariff change would be the date of the last actual meter read (that is, not an estimated meter read) unless a new actual meter read or a new meter is required to support the change in tariff.

Tariff 11 – Billing information for consumption charge

Average daily consumption thresholds

Block 1	**First 13.69 kWh/day**
Block 2	**Next 13.69 kWh/day**
Block 3	**Remaining kWh/day**

Tariff rate for Block 1	**17.456 c/kWh**
Tariff rate for Block 2	**25.352 c/kWh**
Tariff rate for Block 3	**29.740 c/kWh**

The following guide can be used to calculate a quarterly bill for Tariff 11:

Step 1 – Divide total quarterly consumption (kWh) by the number of days in the billing cycle to calculate average daily consumption (kWh/day).

Step 2 – Determine the proportion of average daily consumption (kWh/day) to be charged in each tariff block.

Where average daily consumption is less than or equal to **13.69 kWh/day**:

- Block 1: Multiply average daily consumption (kWh/day) by the number of days in the billing cycle (days) that the premises is connected and by the tariff rate for Block 1 (**17.456 c/kWh**).

Where average daily consumption is greater than **13.69 kWh/day** but less than or equal to **27.38 kWh/day**, sum the individual block calculations as shown below:

- Block 1: Multiply **13.69 kWh/day** by the number of days in the billing cycle (days) that the premises is connected and by the tariff rate for Block 1 (**17.456 c/kWh**);
- Block 2: Multiply (total average daily consumption (kWh/day) minus **13.69 kWh/day**) by the number of days in the billing cycle (days) that the premises is connected and by the tariff rate for Block 2 (**25.352 c/kWh**).

Where average daily consumption is greater than **27.38 kWh/day**, sum the individual block calculations as shown below:

- Block 1: Multiply **13.69 kWh/day** by the number of days in the billing cycle (days) that the premises is connected and by the tariff rate for Block 1 (**17.456 c/kWh**);
- Block 2: Multiply **13.69 kWh/day** by the number of days in the billing cycle (days) that the premises is connected and by the tariff rate for Block 2 (**25.352 c/kWh**);
- Block 3: Multiply (total average daily consumption (kWh/day) minus **27.38 kWh/day**) by the number of days in the billing cycle (days) that the premises is connected and by the tariff rate for Block 3 (**29.740 c/kWh**).

For example, for a customer with consumption of 2,730 kWh in a 91 day billing cycle, the average daily consumption is 30 kWh/day. For this billing cycle, (13.69 kWh/day multiplied by 91 days) would be charged at the Block 1 tariff rate, (13.69 kWh/day multiplied by 91 days) would be charged at the Block 2 tariff rate, and (2.62 kWh/day multiplied by 91 days) would be charged at the Block 3 tariff rate.

Supply Voltage

(a) Low Voltage

Except where otherwise stated, the tariffs in Part 1 will apply to supply taken at low voltage (480/240 volts or 415/240 volts, 50 Hertz A.C., as required by the distribution entity).

(b) High Voltage

(i) Customer plant requirements.

By agreement between the customer and the distribution entity, supply may be given and metered at a standard high voltage, the level of which shall be prescribed by the distribution entity.

Where high voltage supply is given, a customer shall supply and maintain all equipment including transformers and high voltage automatic circuit breakers but excepting meters and control apparatus beyond the customer's terminals.

(ii) Credits where L.V. tariff is metered at H.V.

Where supply is given in accordance with (i) above and metered at high voltage then, except in cases where high voltage tariffs are determined or provided by agreement to meet special circumstances, the tariffs applied will be those pertaining to supply at low voltage ("the relevant tariff"), EXCEPT THAT, after billing the energy and demand components of the tariff, a credit will be allowed of –

- 5 percent of the calculated tariff charge where supply is given at voltages of 11kV to 33 kV; and
- 8 percent of the calculated tariff charge where supply is given at voltages of 66 kV and above,

(provided that the calculated tariff charge after application of the credit must not be less than the Minimum Payment or other minimum charge calculated by applying the provisions of the relevant tariff.)

Card-operated Meters in Remote Communities

If a customer is a small excluded customer for a premises (as defined in section 23 of the Electricity Act), the distribution entity may at its absolute discretion agree with:

(a) the relevant local government authority on behalf of the customer; and
(b) the customer's retail entity, that the electricity consumed by the customer is to be measured and charged by means of a card-operated meter.

If, immediately prior to 1 July 2007, electricity being consumed by a customer at a premises is being measured and charged by means of a card-operated meter, the electricity consumed at the premises may continue to be measured or charged by means of a card-operated meter.

The methodology for applying the appropriate tariffs to customers subject to card-operated meters is as follows:

(a) If electricity supplied to a residential customer is measured and charged by means of a card-operated meter:
  (i) for Tariff 11 (Residential – Lighting, Power and Continuous Water Heating), all consumption shall be charged at the 'All Consumption' rate (**20.157 c/kWh**), plus a Service Fee of **550.718 c** per week shall apply;
  (ii) for Tariff 31 (Night Rate – Super Economy), all consumption shall be charged at the 'All Consumption' rate (**10.954 c/kWh**); and
  (iii) for Tariff 33 (Controlled Supply – Economy), all consumption shall be charged at the 'All Consumption' rate (**15.654 c/kWh**).
(b) If electricity supplied to a business customer is measured and charged by means of a card operated meter, all consumption shall be charged at the 'All Consumption' rate under Tariff 20 (General Supply) (**19.950 c/kWh**), plus a Service Fee of **776.020 c** per week shall apply.

Other Retail Fees and Charges

A retail entity may charge its customers on a Standard Retail Contract the following:

(a) if, at a customer's request, the retail entity provides historical billing data which is more than two years old – a maximum of **$30**;
(b) retail entity's administration fee for a dishonoured payment – a maximum of **$10**; and
(c) financial institution fee for a dishonoured payment – no more than the **fee incurred** by the retail entity.

Part 4

CONCESSIONAL APPLICATIONS OF TARIFFS 11 and 12 (RESIDENTIAL)

***Tariff 11* – Residential (Lighting, Power and Continuous Water Heating) (Inclining Block) and *Tariff 12* – Residential (Lighting, Power and Continuous Water Heating) (Time-of-Use) are available to customers satisfying the criteria set out in any one of A, B or C, as follows:**

A. Those separately metered installations where all electricity consumed is used in connection with the provision of a Meals on Wheels service or for the preparation and serving of meals to the needy and for no other purpose.

B. Charitable residential institutions which comply with all the following requirements—

(a) Domestic Residential in Nature The total installation, or that part supplied and separately metered, must be domestic residential (i.e. it must include the electricity usage of the cooking, eating, sleeping and bathing areas which are associated with the residential usage). Medical facilities, e.g. an infirmary, which are part of the complex may be included as part of the total installation; and
(b) Charitable and Non-Profit The organisation must be:
  (i) a deductible gift recipient under section 30-227(2) of the *Income Tax Assessment Act 1997* to which donations of $2.00 and upwards are tax deductible; and
  (ii) a non-profit organisation that:
    A. imposes no scheduled charge on the residents for the services or

accommodation that is provided (i.e. organisations that provide emergency accommodation facilities for the needy); or

B. if scheduled charges are made for the services or accommodation provided, then all residents must be pensioners or, if not pensioners, persons eligible for subsidised care under the *Aged or Disabled Persons Care Act 1954*, the *National Health Act 1953* or the *Nursing Homes Assistance Act 1974*.

C. Organisations providing support and crisis accommodation which comply with the following requirements—

The organisation must:

(a) meet the eligibility criteria of the Supported Accommodation Assistance Program (SAAP) administered by the State Department of Communities and is therefore eligible to be considered for funding under this program. (Funding provided to organisations under SAAP is subject to Part 3, Sections 10 to 13 inclusive, of the *Family Services Act 1987*); and

(b) be a deductible gift recipient under section 30-227(2) of the *Income Tax Assessment Act 1997* to which donations of $2.00 and upwards are tax deductible.

Part 5

RELIEF FROM ELECTRICITY CHARGES WHERE DROUGHT DECLARATION IN FORCE

Customers of Ergon Energy Queensland Pty Ltd

A customer of Ergon Energy Queensland Pty Ltd who is a farmer in a drought declared area or whose property is individually drought declared under Queensland Government administrative processes is eligible for one or more of the following forms of relief from electricity charges:

(B) Waiving of Fixed Charge Components of Electricity Charges

If a customer of Ergon Energy Queensland Pty Ltd who is a farmer in a drought declared area or whose property is individually drought declared has no water to pump, the fixed components of the customer's electricity charges shall be waived. These fixed charge components include minimum payments, service fees, annual fixed charges under Tariff 66 and guarantee agreement shortfall charges.

Provided the drought declaration remains operative, the waiver applies to all fixed charges applicable to any account covering the period in which pumping ceased and to any subsequent account until the customer once again has water to pump. If the operative drought declaration is revoked before the customer once again has water to pump, the waiver shall continue to apply until water is available or until 12 months after the revocation of the drought declaration, whichever is the earlier.

(C) Deferral of Payment

If a customer of Ergon Energy Queensland Pty Ltd who is a farmer in a drought declared area or whose property is individually drought declared cites financial difficulties as a result of the drought, the customer is entitled to defer payment of the customer's electricity accounts relating to farm consumption.

Ergon Energy Queensland Pty Ltd may charge interest on deferred accounts. However, the rate of any interest charged must not be more than the Bank Bill reference rate for 90 days, as published on the first business day of each quarter.

Subject to the maximum rate of interest that may be charged, the terms of the deferred payment and the repayment of deferred amounts following revocation of the drought declaration will be as agreed between Ergon Energy Queensland Pty Ltd and the customer concerned.

Eligibility for Relief

A customer of Ergon Energy Queensland Pty Ltd seeking relief from electricity charges on the basis that the customer is a farmer who is in a drought declared area or whose property is individually drought declared, must apply in writing to Ergon Energy Queensland Pty Ltd.

If required by Ergon Energy Queensland Pty Ltd, the customer must provide:

(a) evidence that the customer's property is in a drought declared area or is individually drought declared, including the effective date of such drought declaration;

(b) evidence of the water pumping restrictions applicable to the customer's property; and

(c) evidence that the customer is experiencing financial difficulties as a result of the drought.

Standard Retail Contract customers of other retail entities

Standard Retail Contract customers of retail entities other than Ergon Energy Queensland Pty Ltd who are farmers in drought declared areas or who have a property which is individually drought declared under Queensland Government administrative processes can apply directly to the Department of Employment, Economic Department and Innovation for relief from electricity charges as outlined in (B) above.

Standard Retail Contract customers of other retail entities taking supply under Tariff 68 at 30 June 2007 will be supplied under other tariffs appropriate to their installations.

APPENDIX E: ALTERNATIVE NETWORK TARIFFS FOR LARGE CUSTOMERS BASED ON ENERGEX NETWORK TARIFFS

Retail tariff	*Energex network tariff*	*Fixed charge*	*Demand charge*	*Capacity charge*	*Variable rate (flat)*
		c/cust/day	*$/kW/month*	*$/kW/month*	*c/kWh*
Tariff 42 - Over 100 MWh small (Demand)	8300	1501.000	17.753	0.000	1.017
Tariff 43 - Over 100 MWh large (Demand)	8100	2894.000	15.988	0.000	1.017
Tariff 53 - High voltage (demand)	8000	4946.000	12.174	0.000	1.017
Tariff 54 - Connection Asset Customers	8000	4946.000	12.174	0.000	1.017
Tariff 55 - Individually Calculated Customers	8000	4946.000	12.174	0.000	1.017

APPENDIX F: ACIL PRICE DISTRIBUTION APPROACH

At the time the Authority released its Draft Methodology Report, it proposed to use a new approach to estimating energy costs involving consideration of price distributions rather than the hedging-based approach it had used previously. This was a response to an apparent lack of contract trading data due to uncertainty surrounding the introduction of a carbon tax on 1 July 2012. As it turns out, there now appears to be adequate data to continue with the hedging-based approach to estimating energy costs. However, as ACIL had undertaken parallel work using its suggested price distribution approach, the Authority has included some of the results from that work here for the interest of stakeholders.

In general terms (the detail can be found in ACIL's Draft Report to the Authority), ACIL's price distribution approach involves estimating the price that a retailer would be willing to pay in purchasing energy to meet the load of customers while mitigating a range of risks, principally those flowing from the impacts on the spot price of weather and plant outages.

To implement this approach, ACIL first constructs weather and outage-based load data for 2012-13 for each NEM region and settlement class. As noted in Chapter 3, this differs slightly from the Draft Methodology Paper, in which the Authority proposed to estimate energy costs for each tariff individually. These settlement classes include each distributor's NSLP, the two Energex controlled load profiles and Energex's unmetered load profile. For consideration, ACIL also developed energy cost estimates based on average customer profiles for large customers in Energex's area.

As for the hedging strategy approach discussed in Chapter 3, ACIL then uses its Powermark proprietary model to develop NEM spot price forecasts for 2012-13 which it then combines with the forecast load profiles for 2012-13 to establish a distribution of 410 load-weighted annual prices for each regulated retail tariff. In ACIL's view, the mean of these price distributions represents the price that a retailer would be willing to pay for energy, over time, to cover the load of each settlement class.

ACIL then escalates the mean of the distribution of each settlement class to account for energy losses and the time value of money associated with forward purchasing hedging contracts.

ACIL suggests that its price distribution approach recognises that a prudent retailer would hedge risks through energy purchase contracts and that this would incur extra costs, or a premium, over the expected spot market price and that an efficient retailer would contract to a level where the exposure to high spot prices was kept to a level acceptable to the retailer, based on its appetite for risk and financial capability to ride out periods of high spot prices.

However, ACIL was not able to estimate with any accuracy the extent to which the difference in risk aversion between retailers would affect the premium over the spot price that retailers would be willing to incur in purchasing forward energy contracts.

Nevertheless, Table F.1 shows ACIL's wholesale energy cost estimates (inclusive of carbon and energy losses) for each settlement class in 2012-13 based on the price distribution approach. These estimates can be compared to those in Table 3.4.

Table F.1 – Wholesale Energy Cost Allowances for 2012-13 Including Losses and Carbon Using Price Distribution Approach

Settlement class	*Retail Tariff*	*Allowance (carbon cost inclusive) ($/MWh)*
Energex NSLP	11, 12, 20, 22,41	$69.46
Energex Controlled Load 9000	31	$44.99
Energex Controlled Load 9100	33	$52.82
Ergon Energy NSLP	42, 43, 44,53, 54, 55	$63.55
Energex Unmetered Supply	71, 91	$45.76

Source: ACIL Tasman, Estimated Energy Purchase Costs for 2012-13 retail tariffs, March 2012.

APPENDIX G: ASSUMPTIONS USED TO DETERMINE CUSTOMER IMPACTS

Table G.1: Residential tariff assumptions

Retail tariff	**2011-12**	**2012-13**		
	Volume Flat	Volume Off Peak	Volume Shoulder	Volume Peak
	kWh per annum	*kWh per annum*	*kWh per annum*	*kWh per annum*
Tariff 11 - Residential (inclining block) low	3,000			
medium	5,370			
high	11,000			
Tariff 12 - Residential (time-of-use)	*100%*	*27%*	*50%*	*23%*
low	3,000	810	1,500	690
medium	5,370	1,450	2,685	1,235
high	11,000	2,970	5,500	2,530
Tariff 31 - Night rate (super economy)	2,066			
Tariff 33 - Controlled supply (economy)	1,965			

Table G.2: Small business tariff assumptions

Retail tariff	**2011-12**				**2012-13**			
	Demand	Volume Flat	Volume Off Peak	Volume Peak	Demand	Volume Flat	Volume Off Peak	Volume Peak
	kW per month	*kWh per annum*	*kWh per annum*	*kWh per annum*	*kW per month*	*kWh per annum*	*kWh per annum*	*kWh per annum*
Tariff 20 - Business (flat rate)		7,683				7,683		
Tariff 21 - General Supply (*declining block tariff*)		303				303		
Tariff 22 - Business (time-of-use)			*50%*	*50%*			*50%*	*50%*
			28,329	28,329			28,329	28,329
Tariff 37 - Non Domestic Heating (time of use - *Obsolete*)			*90%*	*10%*			*50%*	*50%*
			15,838	1,760			8,800	8,800
Tariff 41 - Low voltage (demand)	80	80,000			80	80,000		

Table G.3: Large business assumptions

Retail tariff	2011-12					2012-13		
	Capacity	Demand	Volume Flat	Volume Off Peak	Volume Peak	Capacity	Demand	Volume Flat
	kW per month	*kW per month*	*kWh per annum*	*kWh per annum*	*kWh per annum*	*kW per month*	*kW per month*	*kWh per annum*
Tariff 42 - Over 100 MWh small (Demand)		65	500,000				65	500,000
Tariff 43 - Over 100 MWh medium (Demand)		207	2,000,000				207	2,000,000
Tariff 44 - Over 100MWh large (demand)	700	458		*45%* 1,575,000	*55%* 1,925,000	700	458	3,500,000
Tariff 53 - High voltage (demand)	700	514		*40%* 800,000	*60%* 1,200,000	700	514	2,000,000
Tariff 54 - Connection Asset Customers	700	500		*30%* 3,000,000	*70%* 7,000,000	700	500	10,000,000
Tariff 55 - Individually Calculated Customers	700	500		*30%* 13,500,000	*70%* 31,500,000	700	500	45,000,000

Table G.4: Farming tariff assumptions

Retail tariff	2011-12				2012-13			
	Demand	Volume Flat	Volume Off Peak	Volume Peak	Demand	Volume Flat	Volume Off Peak	Volume Peak
	kW per month	*kWh per annum*	*kWh per annum*	*kWh per annum*	*kW per month*	*kWh per annum*	*kWh per annum*	*kWh per annum*
Tariff 62 - Farm (time of use)			*40%* 1,936	*60%* 2,905			*40%* 1,936	*60%* 2,905
Tariff 63 - Farm (time-of-use - *obsolescent*)			*98%* 1,196	*2%* 24			*98%* 1,196	*2%* 24
Tariff 64 - Irrigation (time-of- use *obsolescent*)			*45%* 265	*55%* 324			*37%* 218	*63%* 371
Tariff 65 - Irrigation (time-of- use)			*50%* 2,395	*50%* 2,395			*42%* 2,011	*58%* 2,778
Tariff 66 - Irrigation	21	9,911			21	9,911		
Tariff 67 - Farm - (Rural Subsidy Scheme)		8,800				8,800		
Tariff 68 - Irrigation (drought declared areas)		2,515				2,515		