QUEENSLAND COMPETITION AUTHORITY

Issues Paper

Review of Regulated Retail Electricity Tariffs and Prices

June 2011

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SUBMISSIONS

Public involvement is an important element of the decision-making processes of the Queensland Competition Authority (the Authority). The Authority is releasing this Issues Paper as a first step in its *Review of Regulated Retail Electricity Tariffs and Prices.* The Authority has identified a number of key issues that it will need to consider in accordance with the Direction for the review. The issues that have been identified are not exhaustive but are provided to assist stakeholders in preparing their submissions. 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 two printed copies are provided together with an electronic version on disk (Microsoft Word or Adobe PDF format) or by e-mail. Submissions, comments or inquiries regarding this Review should be directed to:

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The **closing date** for submissions is 5 August 2011.

For further enquiries contact Gary Henry on (07) 3222 0504.

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 a copy of each version of these submissions (i.e. the complete version and another excising confidential information) could be provided. 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 and 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.

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1. INTRODUCTION

On 11 May 2011, the Queensland Competition Authority received a Ministerial Direction (see **Appendix 1**) under section 10(e) of the *Queensland Competition Authority Act 1997* (the QCA Act) from the Minister for Finance and the Arts and Acting Treasurer and Minister for State Development and Trade (the Minister). The Direction Notice requires the Authority to investigate, and report on:

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

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

Where:

(a) the N component – network costs should be treated as a pass through to customers. The N cost component of each tariff should be equal to the approved Energex network price for the relevant tariff year; and

(b) the R component – the R cost component of each tariff should include appropriate allowances for energy and retail costs.

The Authority must provide a Draft Report in March 2012 and a Final Report by 31 May 2012.

1.1 Minister's Direction Notice

In addition to the above, the Authority is required to have regard to the following:

(a) all tariffs (excluding those specified below) are to be cost-reflective;

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

(c) an appropriate tariff for customers who are supplied under the Rural Subsidy Scheme or are located in a drought declared area should be considered;

(d) consideration should be given to a voluntary cost-reflective time-of-use tariff for domestic customers;

(e) consideration should be given to an appropriate tariff for electricity supplied to continuously operating traffic signals installed on a road; and

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

In reporting on a possible alternative schedule of retail electricity tariffs, the Authority is required to note the following:

(a) as at 1 July 2012, access to regulated tariffs will be removed for large non-residential customers in Energex's network area who consume over 100 megawatt hours per annum;

(b) as at 1 July 2012, all obsolete and declining block tariffs will be removed from the tariff schedule and any customers on these tariffs will be required to transition to an alternative tariff;

(c) in relation to a voluntary time-of-use tariff for domestic customers, any customer who chooses to transfer to this tariff, providing they have the appropriate metering, will be permitted to transfer back to the standard regulated tariff for domestic customers at any time if they choose to; and

(d) seasonal tariffs are not to be considered.

In addition, the covering letter from the Minister for Energy and Water Utilities noted that:

(a) all retail tariffs should be aligned with the relevant network tariff;

(b) the Government has endorsed and inclining block network tariff for domestic customers commencing 1 July 2012; and

(c) the regulated street lighting tariff will in future only apply in the Ergon Energy network area.

The Minister's covering letter and full Direction Notice are provided in **Appendix 1**.

1.2 Background to the Review

In June 2009, the Authority was directed by the Premier and the Treasurer to conduct a *Review of Electricity Pricing and Tariff Structures* (the 2009 review). The 2009 review required the Authority to:

(a) examine the current Benchmark Retail Cost Index (BRCI) methodology and alternative pricing-setting methodologies for reflecting the costs of supplying electricity including network costs and accounting for all State and Commonwealth Government environmental obligations; and

(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 provide an incentive for customers to use electricity more efficiently.

The Authority conducted the 2009 review in two stages. In its Final Report on Stage 1, the Authority concluded that:

(a) the current BRCI methodology had a number of flaws, including that it:

  (i) applied a single escalator to a variety of tariffs which have different cost structures;

  (ii) used a weighted average of long run marginal cost (LRMC) and energy purchase costs in calculating the wholesale cost of energy and was therefore not indicative of the actual costs incurred by retailers; and

  (iii) used the average increase in network costs for both Energex and Ergon Energy despite the fact that most, if not all, retail competition was occurring in Energex's distribution area;

(b) existing tariffs and prices were 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 costs of their electricity use. However, the scope for change was limited by existing metering equipment; and

(c) an alternative N+R pricing approach would offer significant improvements over the existing BRCI methodology.

The Authority recommended that the proposed N+R approach should be based on a three-year price path which would include:

(a) an annual review of wholesale energy purchase costs with a reset of the price path if the estimates moved outside a predetermined band;

(b) an automatic re-opening of the pricing decision on the introduction of new policy initiatives, such as a Carbon Pollution Reduction Scheme, with periodic reviews of wholesale energy purchase costs thereafter while the energy cost remained volatile;

(c) full pass through of network costs, but on the same bill with the Community Service Obligation (CSO) payments for regional Queensland customers to be maintained to achieve the Queensland Government's uniform tariff policy objective;

(d) a "bottom-up" review of tariffs with notified prices; and

(e) consideration of transitional measures once the extent of any likely price change became clearer.

In Stage 2 of the 2009 review, the Authority concluded that:

(a) retail tariffs should be made as cost reflective as possible;

(b) network and retail tariffs should be aligned; and

(c) a voluntary time-of-use tariff be introduced for those residential customers with interval meters.

The Authority also suggested that adding a seasonal component to some tariffs could be warranted.

While the Authority recommended that its preferred approach to achieving these objectives would be to develop a new set of cost reflective tariffs rather than to amend the existing tariff schedule, it also noted that, should the Government choose to retain the existing tariff schedule, some improvements could be achieved by consolidating a number of existing tariffs, removing obsolete tariffs and rebasing prices of the existing tariffs to reflect costs determined under the N+R approach.

The current Direction follows the Government's consideration of the Authority's findings and recommendations in its 2009 review.

1.3 The Queensland Regulated Retail Electricity Market

State of the Market

For some large electricity consumers, the option to choose their electricity retailer commenced in 1998. However, for the majority of consumers, including all residential consumers, 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 consumers, including those on notified prices. Consumers who take up such an offer transfer from the notified price to the market contract price they have agreed in the market contract with the retailer of their choice.

However, notified prices continue to remain an important feature of the Queensland retail electricity market. This is partly because competition in Queensland has not been uniform and, in much of the State, there is no alternative for consumers other than to access electricity supply at the notified price. As at the end of March 2011, approximately 59% of small customers (those consuming less than 100 MWh per year) and 54% of large customers in Queensland remain on notified prices.

Notified prices act as a safety net for those consumers who are not offered, or choose not to accept, a market contract from a retailer. Small consumers who accept a market contract may also revert to a non-market contract at the notified price in the future, subject to any contractual conditions that may apply to them under their market contract.

Existing Price Setting Arrangements

Since the commencement of FRC, notified prices have been adjusted annually in accordance with the Benchmark Retail Cost Index (BRCI) process prescribed in the *Electricity Act 1994* (the Electricity Act) and the *Electricity Regulation 2006* (the Electricity Regulation).

There are currently 20 regulated retail tariffs for which notified prices are set using the BRCI methodology. While some of the current tariffs were introduced more recently, most were introduced over 20 years ago. The current range of tariffs available to consumers consists of residential, business and agricultural/farming tariffs. However, in some circumstances, the type of tariff available to individual consumers depends on the location of their premises and whether appropriate metering is in place to record the required consumption pattern.

The annual calculation of the BRCI by the Authority does not involve an assessment of the efficient cost of supplying electricity. Rather, the legislation requires the Authority to estimate the annual percentage change in the cost of supplying electricity to Queensland consumers and to use this percentage change as an escalation factor to increase (or decrease) the existing notified prices. The last BRCI escalation to be applied to notified prices was for the 2011-12 tariff year.

Policy Considerations

Uniform Tariff Policy

A feature of the Queensland retail electricity market is the application of the Uniform Tariff Policy (UTP). In order to ensure uniformly priced electricity to all customers throughout the State, the Queensland Government currently ensures pricing parity between rural and regional customers and those in South East Queensland through a regional subsidy.

The UTP allows customers of the same class to access uniform retail tariffs and pay the same notified price for their electricity supply, regardless of their geographical location. The UTP works by subsidising customers in Ergon Energy’s distribution area where notified prices are considerably lower than the actual costs of supplying electricity. The actual costs of supply are high because electricity must be transported over long distances and there are fewer people to share these costs.

In order to support its UTP, the Queensland Government currently provides a regional subsidy by way of a CSO payment to fund the difference between the actual costs charged by the distributor and the amount that is recovered by Ergon Energy Queensland from notified prices.

1.4 Process for this Review

The Direction requires the Authority to report on two components, a 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.

There are thus two key issues to be considered in this review:

(a) the cost components required under the N+R approach. These costs will be recouped by retailers through retail electricity tariffs; and

(b) the structure of the retail electricity tariffs under the N+R approach. To accommodate the N+R approach, these tariffs must be based on Energex's approved network tariffs.

This Issues Paper addresses both parts of the review. In doing so, it builds on the Authority's findings and recommendations of the 2009 Review (where relevant and consistent with the Direction) and identifies the key issues on which the Authority particularly seeks stakeholder comment at this time.

In conducting this review, the Authority will provide as much public consultation with stakeholders as is possible given the reporting time constraints specified in the Direction. Submissions are invited in response to this Issues Paper and should be received by the Authority no later than 5 August 2011.

An initial timetable for the review is set out below. This timetable may have to be varied as the review progresses.

Table 1.1: Initial Timetable for the Review

Task	***Indicative dates***
Release of Authority's Issues Paper	27 June 2011
Submissions on Issues Paper due	**5 August 2011**
Release of Authority's Draft Report and consultants' reports	March 2012
Submissions on Draft Report due	**Early April 2012**
Release of Authority's Final Report, consultants' final reports	**31 May 2012**

2. TREATMENT OF NETWORK COSTS

2.1 Introduction

Network costs include the costs associated with the use of transmission and distribution networks and typically account for around 50% of the total cost of providing electricity to households.

The Direction requires the Authority to adopt a cost-reflective N+R pricing model under which the network costs (N) are to be treated as a straight pass through to customers. Further, the Direction specifies that the N component of each tariff should be equal to the approved Energex network price, regardless of which network customers are actually connected to. This requires that, in the Ergon Energy distribution area, regulated retail prices will reflect the Energex tariff structure and costs of supply in South East Queensland, while Ergon Energy (distribution) will continue to charge retailers its cost reflective network charges.

2.2 Network tariffs

Under the network pass-through approach to setting regulated retail tariffs specified in the Direction, network costs would be represented as a separate price component of the total bill and would be adjusted each year to reflect changes in the Australian Energy Regulator (AER) approved Energex network tariffs and prices.

2.3 Energex's network tariffs

Energex has AER approved network prices for distribution and transmission services, though it would be the combined network use of system charge that is passed through to customers.

Energex's transmission network prices allow it to recover transmission network costs that it has paid (predominantly) to Powerlink (Queensland's transmission entity) for the use of the transmission network. Powerlink's charges are the largest component of transmission costs and are set by the AER. There are also a number of other transmission-related costs incurred by Energex, including avoided transmission use of system (TUOS) payments made to embedded generators and payments to other distribution network operators for transmission-like network services. Each year, the AER approves Energex's transmission network prices at the same time that it approves Energex's distribution network prices.

Energex's distribution network prices are designed to recover the costs Energex incurs in providing distribution network services to customers. The AER regulates the amount of revenue that Energex is allowed to recover through distribution network charges annually and approves network prices designed to raise the required amount of revenue.

Under the N+R approach required by the Direction, retail tariffs are to be aligned with Energex's network tariffs. As a result, the number and structure of regulated retail tariffs must reflect Energex's network tariffs.

Energex's approved network tariffs and prices for 2011-12 are provided at **Appendix 2**. The Authority has asked Energex to provide its proposed tariff structure for 2012-13 and it will be these network tariffs that will set the basis for constructing a complementary set of retail tariffs during this review. Energex's proposed 2012-13 tariff will be released as soon as it is made available.

Appendix 3 provides the current regulated retail tariffs as published by the Authority in the Government Gazette on 31 May 2011. As can be seen by comparing this with the Energex network tariffs in Appendix 2, there is very little correlation currently between the network and retail tariff structure. In its 2009 Review, the Authority made recommendations for simplifying the retail tariff structure by removing obsolete tariffs and consolidating a number of other tariffs. However, the issue of aligning the network and retail tariffs under the N+R approach goes beyond this simplification process.

Suitability of existing Energex network tariffs

From Appendix 2, it does not appear that Energex's 2011-12 tariffs would provide a suitable basis for some of the retail tariffs the Authority is required to consider. For example, Energex does not separately identify in its tariff structure an inclining block domestic tariff, a voluntary time-of-use tariff for domestic customers, tariffs designed specifically for farmers and irrigators, or tariffs for customers supplied under the Rural Subsidy Scheme or in drought declared areas.

The starting point for this review, given the N+R approach, must be a set of network tariffs which identify appropriate groups of customers who have broadly similar load profiles and usage requirements.

While Energex may utilise elements of its existing tariff structure to determine network prices for some of these uses or groups of customers, it is not immediately obvious how this might be done. For the purpose of constructing new tariffs and charges, it is essential that the network tariffs provide a clear and easily understood basis for dividing customers into reasonably homogenous groups to whom the associated network costs, and subsequently energy and retail costs, can be sensibly allocated.

This raises a number of issues that need to be considered, including:

(a) The tariff structure at the network level must include all the tariff types that one wishes to see reflected at the retail level. If there is no network tariff for a particular class or category of customer/consumption, there can be no retail tariff for that group of customers.

For example, if there is to be an inclining block retail tariff available for domestic customers, there must be an inclining block network tariff for these customers. If there is to be a retail time of use irrigation tariff, there must be a corresponding time-of-use network tariff.

(b) If some customers are to be supplied at subsidised rates in certain situations, for example, under the Rural Subsidy Scheme, the extent of the subsidy has to be determined and enshrined at the network level.

Decisions regarding the Rural Subsidy Scheme and drought relief, or other public policy issues, are matters for governments to decide, not private sector electricity retailers. In Queensland, the simplest way for the Government to implement its decisions regarding the subsidised cost of electricity for consumers in difficult situations would be to provide its subsidy at the network level because the distributors are wholly owned by the Government. Subsidies could not be applied earlier in the supply chain as the nature of the consumers is not known prior to the distribution level. While payments could be made later in the supply chain, it would be administratively more complex. Nevertheless, this is the way in which some forms of price subsidy are currently provided to customers such as pensioners and other individuals in need.

(c) If the Energex tariffs are to be the basis for charging across the State, the Energex tariff structure will have to also adequately cater for any particular circumstances in the Ergon Energy distribution area that are not encountered by Energex.

For example, 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.

Similarly, the Direction makes clear that, from 1 July 2012, large customers (those consuming over 100MWh per year) in Energex's network area will no longer have access to a regulated retail tariff. Yet large customers in Ergon Energy's distribution area will continue to have access to a regulated retail tariff.

More generally, large customers usually have network prices which are individually tailored to a greater or lesser extent depending on the characteristics of their consumption. However, these charges are paid by the retailers and the notified retail price charged to customers is not based on these network tariffs. This raises questions as to how a generic N component is to be determined for these customers and how this might be treated in a public tariff and pricing schedule. Very large customers generally have a unique network price which reflects their own use of network assets. This is usually commercially sensitive information and therefore treated as confidential.

(d) One of the benefits of adopting an N+R pricing model is that it allows distributors (or at least Energex) to pursue their own demand management objectives.

For example, the interests of retailers and distributors will not always align when it comes to influencing the level of consumption. In general, retailers will prefer to sell more electricity in order to enhance their profitability. While retailers are exposed to spot market prices in the electricity market, they have options available to limit the level of their financial risk. Distributors on the other hand have to be able to meet the peak demand requirement placed on their networks by investing in increased capacity. It is not an option for the distributor to lay off some of this exposure to other parties.

Separating the N and R components allows the distributor to send price signals directly to retail customers about the cost of their network usage. Previously, this has been a difficult, if not impossible, task for Energex and Ergon Energy. This raises issues such as whether Energex's demand management strategies will translate directly to the Ergon Energy network or, more fundamentally, does the Energex network tariff structure provide appropriate scope for managing network demand.

While these issues are central to the Authority's review, it does not have any capacity to influence or determine the Energex tariff structure. Ultimately, the network tariff structure and the associated prices will have to be approved by the AER. If issues are identified with the Energex tariff structure that requires change, the Authority will have to rely on the Government, as owner of the distribution businesses, to facilitate those changes.

The Authority seeks stakeholders' views on the issues raised above, in particular the suitability of the Energex tariff structure as a basis for meeting retail pricing objectives. The Authority is also interested in any other matters concerning the setting of network tariffs which stakeholders consider important to be considered in this review.

2.4 Process for passing through network costs

The Direction requires that Energex's network costs be treated as a pass through to customers. Accordingly, when billing customers, retailers operating in both the Energex and Ergon Energy distribution areas will include an N cost component equal to the approved Energex network charge. However, in Ergon Energy's distribution area retailers will be charged the (generally higher) cost reflective Ergon Energy distribution price. Where Ergon Energy Queensland is the retailer, it will be able to take advantage of the Queensland Government's CSO contribution in the usual way to meet any shortfall between this charge and its actual costs so that non-market customers across the State are able to access electricity supply at a price consistent with the Government's uniform tariff policy. However, other retailers with non-market customers (or competing for market customers) would have to absorb this shortfall.

An alternative approach might be to apply the Government's CSO at the distribution level and allow all retailers to compete for customers in the Ergon Energy distribution area based on the competitiveness of their retail charges.

In Stage 1 of the 2009 Review, there was significant opposition from retailers to the suggestion that the network cost component of a customer's total bill should be separately identified. Retailers generally claimed that, to provide this additional piece of information to customers, would require substantial and costly billing system changes. The retailers therefore proposed that only a single bundled price be shown on customer bills.

While not disputing these claims, the Authority noted that customers could be informed to some extent of the cost of the network component of their bill through the publication of the separate N and R components in the tariff schedule.

Nevertheless, it remains an open question whether and how customers should be informed of the contribution of both network and retail components to their total bill.

The Authority seeks stakeholders' views on any issues that should be considered in relation to the pass through of network costs, in particular, should network and retail costs be separately identified on a customer's bill?

2.5 Maintaining alignment of retail and network tariffs

Adopting an N+R approach to setting regulated retail tariffs requires a formal process to ensure the ongoing alignment of network and retail tariffs.

Aligning the network and retail tariffs ensures the appropriate allocation of costs to (and recovery of costs from) groups of consumers covered by each tariff class. It also ensures that distributors are able to effectively engage in demand management initiatives that rely on price signals being passed through to customers.

As Energex's network prices are routinely approved by the AER just prior to the start of each financial year, any change in the network tariffs proposed by Energex and subsequently approved by the AER will potentially result in a misalignment with retail tariffs which have generally been set at least one month before they are due to come into effect.

One option would be for the Authority to adjust retail tariffs once the AER has approved Energex's network tariffs. However, this would generally leave insufficient time for the Authority to amend the retail tariff structure and determine appropriate price changes or for retailers to incorporate the new retail tariffs into their billing systems in time for the start of the new financial year.

An alternative might be for the Authority to make any required adjustments as promptly as it can once any changes in the tariff structure have been approved by the AER, recognising that this is unlikely to be done prior to the start of the financial year.

The Authority seeks stakeholders' views on how this issue might be best addressed.

3. ENERGY COST COMPONENT OF RETAIL TARIFFS

3.1 Introduction

Under the Direction, the R component of each retail tariff is to include appropriate allowances for energy and retail costs. In the 2009 Review, the Authority identified the following items for possible inclusion in the energy cost component:

(a) the cost of purchasing wholesale energy from the National Electricity Market (NEM);

(b) renewable energy costs incurred by retailers in meeting their obligations under State and Commonwealth Government greenhouse schemes; and

(c) NEM participation fees and charges imposed by the Australian Energy Market Operator (AEMO), as well as the costs associated with network energy losses.

3.2 Estimating Energy Costs

In the 2009 Review, the Authority considered two broad approaches to estimating wholesale energy costs:

(a) a cost-based approach such as the LRMC; and

(b) a market-based approach which estimates the wholesale energy costs involved in supplying electricity at prevailing market prices over a given period.

Having considered the merits of the two approaches in its 2009 Review, the Authority concluded that a market-based approach offered the best method for assessing the wholesale energy costs likely to be faced by retailers. The Authority was of the view that the desire for a competitive electricity market and the need to reflect retailers' actual cost of supplying electricity provided sufficient reasons to move away from the cost-based LRMC, which had been included in the BRCI price setting approach, to a completely market-based energy purchase cost approach. Stakeholder submissions at that time strongly supported moving away from the BRCI approach to estimating energy costs and provided general support for the alternative of using a market-based approach to determine wholesale energy costs.

The Authority was not convinced about the inclusion of an LRMC "floor" for wholesale energy prices, on the basis that there appeared 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 without the need for the additional security of an LRMC "floor" in notified prices in Queensland. The Authority also questioned why this security would be needed with regulated prices but not if the market was entirely deregulated, in which case only market costs would be available.

Developing a Market-based Methodology

A market-based methodology involves establishing the level of energy purchase costs that a representative retailer would incur in supplying the regulated customer load. As the network component (N) of regulated retail tariffs in the N+R approach is to be based on Energex's network tariffs, for consistency, the retail component (R) should also be based on the costs of supply in Energex's network area.

Establishing the energy purchase costs to meet the customer load in Energex's network area will involve:

(a) consideration of the various financial products and hedging strategies that a representative retailer would use to mitigate its potential exposure to high NEM spot market prices; and

(b) decisions about a number of modelling parameters in estimating the market-based energy purchase costs, including:

   (i) forecasting future wholesale spot market prices;

   (ii) data sources for forward contract market prices;

   (iii) the timing and volume of hedging contracts that are likely to be purchased by a representative retailer; and

   (iv) the relevant customer load that a representative retailer would face and how it should be forecast.

Determining a Suitable Hedging Strategy

To determine an appropriate method for estimating the energy purchase costs that a representative retailer would incur in meeting customer load requires assumptions about the hedging strategy a representative retailer would use to manage its exposure to wholesale market volatility, which in turn requires consideration of the level of risk that the retailer would be willing to accept.

Another consideration is the availability and quality of data to determine a reasonable hedging strategy. A significant proportion of the hedging undertaken by retailers is in the form of bilateral agreements with generators for which there is no publically available data. While publicly available data for swap and cap contracts is generally accepted as being reliable, information that is available for less common contracts may be less reliable.

In estimating the purchase costs of energy, regulators have typically determined an optimal portfolio of contracts for hedging a given load and then estimated the cost of holding those contracts. However, they have differed on what might constitute an optimal portfolio of hedging contracts.

In calculating the energy purchase cost component of the BRCI, the Authority used a relatively simplistic hedging approach that assumed that a retailer would attempt to over-hedge its load in order to minimise its exposure to periods of high energy prices. The Authority assumed that, for each quarter, a retailer would purchase:

(a) flat swap contracts up to the 85th percentile of its off-peak load

(b) peak swap contracts up to the 90th percentile of its peak load; and

(c) peak cap contracts up to 105% of its peak load.

While this hedging strategy led to a considerable over-purchase of energy, it significantly reduced the risk of exposure to high-price periods in the spot market.

In New South Wales, the Independent Pricing and Regulatory Tribunal (IPART) used an approach that relied on constructing an "efficient frontier" of hedging strategies[1]. The frontier represented hedging strategies expressed as a mix of electricity purchasing instruments (that is, NEM spot market purchases and hedging contracts of various kinds) for a range of risks that minimise the variability in a retailer's purchase cost for a given customer load. This approach

[1] IPART, *Review of regulated retail tariffs and charges for electricity 2010-2013*, Final Report, March 2010

assumes that there are many strategies that are deemed to be efficient, each representing a different level of risk and return. IPART adopted a conservative hedging strategy in which the retailer is assumed to be willing to take on risk up to the point where the change in the expected costs of purchasing energy are lowest for a given increase in risk.

The Independent Competition and Regulatory Commission (ICRC) adopted a different approach to estimating energy purchase cost in its Final Decision on retail prices in the ACT for 2010-2012[2]. The ICRC was concerned that the nature of the electricity market, characterised by a commodity that cannot be stored and a particularly volatile spot price, made it impossible to perfectly hedge. As a result, it developed a model for estimating energy costs that was broadly based on corporate finance concepts. The approach relies heavily on the most recent estimate for electricity costs over a period (the forward price of swap contracts) and adjusts this to account for the observed volatility of the spot price and the hedging costs likely to be incurred by a retailer in covering its load.

In the 2009 Review, the Authority proposed to investigate potential options for adopting a simpler modelling approach that can be undertaken using as much publicly available data as possible. However, some stakeholders were concerned with the Authority's proposal because they considered that the real costs and risks to a retailer may not be adequately captured by a simpler modelling approach.

The Authority seeks stakeholders' views on the following:

- **Is a hedging-based model the most appropriate way to estimate energy costs given complexities and risks involved in the Queensland electricity market?**
- **What mix of hedging contracts would be appropriate to include in the hedging strategy?**
- **How (if at all) should the Authority take account of bi-lateral hedging contracts between generators and retailers?**
- **Are there any other factors the Authority should consider in relation to this issue?**

Wholesale Spot Price Forecasts

Estimating market-based energy purchase costs will involve making assumptions about future wholesale spot market prices against which forward contracting volumes and prices would need to be settled to work out efficient energy purchase costs.

The Authority considers that forecasting wholesale spot market prices with any degree of accuracy and credibility will invariably require the use of proprietary electricity market simulation models that are capable of simulating spot prices that would occur in the NEM.

Previously, the Authority (in its BRCI decisions), IPART and the Essential Services Commission of South Australia (ESCOSA)[3] have relied on expert consultants' proprietary electricity market simulation models to generate future sport prices. In its 2010-12 decision, the

[2] ICRC, *Final Decision: Retail prices for non-contestable electricity customers 2010-2012*, Report 7 of 2010, June 2010.
[3] ESCOSA, *2010 Review of Retail Electricity Standing Contract Price Path: Final Inquiry Report and Final Price Determination*, December 2010.

ICRC adopted a simpler modelling approach, relying on historical spot price outcomes against which it modelled forward contract prices[4].

The Authority seeks stakeholders' views on the following:

- **What are the likely advantages and disadvantages of using proprietary electricity market simulation models that are capable of simulating spot prices for every half hour trading interval as would occur in the NEM?**
- **Are there any simpler modelling alternatives, such as the historical spot price approach adopted by the ICRC, that the Authority could rely on to forecast future wholesale spot prices in the NEM?**
- **Are there any other factors the Authority should consider in relation to this issue?**

Source of Forward Contract Prices

Once an appropriate hedging strategy is determined, the Authority will have to estimate the cost to a retailer of purchasing those forward contracts.

One source of forward contract price data commonly used by regulators is NEM contract price settlement data from the Sydney Futures Exchange (SFE) that is prepared by d-cypha Trade. Under the BRCI process, the Authority used d-cypha Trade data. The ICRC and ESCOSA have also used d cypha Trade data to determine retail prices. The ICRC noted that there was strong stakeholder support for use of publicly available data to estimate energy purchase costs[5] and that transaction volumes represented by d cypha Trade had increased in recent years.

The use of publicly available market data has advantages, particularly in terms of transparency. Observed market prices reflect the expectations of a wide range of market participants, each taking into account the information available to them. However, publicly available data may not be suitable in situations where the markets they reflect lack liquidity, or where there are high levels of uncertainty affecting energy markets. As noted by IPART, market prices will increase to reflect uncertainty and it may not be appropriate to set the energy purchase cost (and therefore regulated retail prices) on this basis.

An alternate source of data on forward contact prices is available from the Australian Financial Markets Association (AFMA). AFMA bases its dataset on a survey in which industry participants are asked at what prices they would be prepared to buy and sell particular products. As a result, AFMA data does not represent actual traded prices, but rather, is an industry survey based on what some of the participants are prepared to trade at. In its 2010-13 retail pricing review, IPART rejected the use of AFMA data on the grounds that, since it was an industry price survey, it was potentially open to manipulation.

An alternative method to using publicly available sources of data is to engage a specialist consulting firm to forecast forward contract prices. In its 2010-2013 retail pricing review, IPART relied on modelled forward contract prices prepared by Frontier Economics. IPART decided to use simulated market data because there was insufficient liquidity in the forward contracts market in the latter years (2012-13) of the determination period and because it was not clear to what extent the forward prices in the latter years had been affected by the (then) Carbon Pollution Reduction Scheme (CPRS).

[4] ICRC, *Final Decision: Retail prices for non-contestable electricity customers 2010-2012,* Report 7 of 2010, June 2010.

[5] ICRC, *Final Technical Paper: Model for determining the energy purchase cost of the transitional franchise tariffs,* Report 3 of 2010, March 2010.

IPART's concerns regarding forward data over a three-year price setting period are not particularly relevant to the Authority in this instance because the Authority is required to determine retail prices for only a single year.

The Authority seeks stakeholders' views on the following:

- **What source(s) of data should the Authority use to estimate the cost of forward contract prices?**
- **Are there any other factors the Authority should consider in relation to this issue?**

Timing and Treatment of Forward Contract Purchasing

Estimating the cost of the forward contract purchasing strategy requires a decision about the timing of contract purchases. Forward contracts can be prices based on a point in time estimate or a rolling average of contract prices over a period of time. Observable market data on forward contract prices is typically volatile, so the decision on the time at which contract prices are assessed can potentially have a significant impact on the level of final regulated retail tariffs.

It is generally accepted that a prudent retailer purchases its forward contracts over time, building up its portfolio slowly rather than attempting to purchase all its required forward contracts in one block immediately prior to the contract period. However, in reality, the timing of contract purchases is strongly influenced by the degree of certainty regarding the volume and shape of the retail load. For the load of customers that have accepted a fixed term market contract with a retailer, the retailer will generally purchase forward contract cover for the length of the retail contract and prior to the commencement of the retail contract.

However, the forecast load of customers on regulated retail tariffs or market contracts that are not of fixed length is more uncertain since these customers can accept an offer with a competing retailer at any time.

In its BRCI decisions, the Authority made the assumption that a prudent and efficient retailer was likely to purchase forward contracts to meet its customers' loads over a rolling 24-month period in advance of the tariff year for which the energy was being hedged.

Similarly, the ICRC in its Final Decision on retail pricing for 2010 2012 calculated the forward contract prices as the average of the 2012 financial year settlement price over the period 1 July 2009 through 31 May 2011, implying a 23-month averaging period.

Another option for calculating contract prices would be to use a volume-weighted average of contract sales as this may provide a better proxy for the costs actually being faced by retailers in Queensland.

An alternative option, which IPART used in its 2010-13 determination, is a 'point in time' estimate, rather than an average of contract prices over a period. IPART's decision to use the point in time estimate reflected its decision to use its consultant's simulated forward contract prices, rather than publicly available data on settled forward contract prices.

A key advantage of using a rolling average approach to forward contract prices is that it will tend to smooth volatility in contract prices over time. While a rolling average approach may be practical when the market based energy purchase cost is based on publicly-available contract prices, it may be less practical if estimating the energy purchase cost based on simulated forward contract prices (as IPART noted).

The Authority seeks stakeholders' views on the following:

- **What assumptions should be made about the timing of contract purchasing for a representative retailer?**

- **Should the Authority consider using a volume-weighted average in determining contract prices for its market-based energy purchase cost allowance?**

- **Are there any other factors the Authority should consider in relation to this issue?**

Customer Load Forecasts

In order to calculate a market-based estimate of energy purchase costs, it will be necessary to estimate the load of customers on retail tariffs in Energex's network area. The level and shape of this load will be a key determinant of the efficient mix of hedging contracts used by the representative retailer to meet the regulated tariff load.

In the 2009 Review, a number of stakeholders suggested that, in order to determine cost reflective energy purchase costs of customers in Energex's distribution area, the best source of customer load would be Energex's Net System Load Profile (NSLP).

The NSLPs are publicly available data used to settle the wholesale energy consumption for all customers with accumulation meters, whether they are on a market contract or regulated retail tariff. Other regulators have also used, or at least considered, the NSLPs as a proxy for regulated customer loads in estimating energy purchase costs in their jurisdictions[6][7].

It may be appropriate to adjust the most recent NSLP data to reflect up-to-date forecasts of customer load for the forthcoming tariff year. In the BRCI process, the Authority utilised AEMO's annual Electricity Statement of Opportunities (ESOO) and Powerlink's Annual Planning Report (APR) to adjust historical load data. However, as the ESOO and APR forecasts are related to Queensland-wide load, they may need to be adjusted in order to reflect the likely changes in the NSLP for Energex's load only.

The Authority seeks stakeholder views on the following:

- **Would Energex's NSLP data be suitable for estimating the consumption profile of customers on retail tariffs in Queensland?**

- **Are there any other sources of load demand forecasts, other than AEMO's annual ESOO publication forecasts, that the Authority should consider in forecasting the customer load?**

- **Are there any other factors the Authority should consider in relation to this issue?**

3.3 Use of LRMC as a Price Floor

In the 2009 Review, the Authority considered the use of the LRMC of generation as a floor price for energy purchase costs. Retailers argued for this approach to provide them with the ability to underwrite future investment in generation capacity by providing pricing certainty to the generation sector.

The Authority was not persuaded by these arguments at that time.

[6] ICRC, *Final Decision: Retail prices for non-contestable electricity customers 2010-2012,* Report 7 of 2010, June 2010

[7] IPART. *Review of regulated retail tariffs and charges for electricity 2010-2013*, Final Report, March 2010.

While other regulators have either used or considered using LRMC as a floor price for the energy purchase cost allowance in their recent retail pricing decisions, their views on the appropriateness of the LRMC floor have differed significantly.

IPART was required by its terms of reference to use a LRMC floor price in determining the energy cost allowance for its 2010 2013 pricing decision without being asked to determine whether the use of a LRMC floor was in the long-term interest of customers or whether it facilitated a stable or efficient electricity market[8].

As a transitionary step to removing price regulation in South Australia, ESCOSA modified its approach to determining regulated retail prices in its 2011-2014 determination[9] to include low and high limits on regulated retail prices that reflected low and high cost estimates of LRMC.

The ICRC, in its recent Final Decision on retail prices for 2010-2012[10], noted that there were a number of reasons why the LRMC should not be adopted as a floor to its calculations. Amongst other things, the ICRC noted that the benefit to generators of having a higher energy cost allowance in regulated retail tariffs is unproven and that higher energy cost allowances do not flow upstream to generators unless the retailer is 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[11].

Under the BRCI, the Authority was required to estimate the LRMC of energy but this was then combined with its estimate of market-based energy purchase costs to arrive at an average energy cost. The LRMC was not used as a floor for retail prices.

The Authority invites stakeholders' comments on the following:

- **Should energy costs include an LRMC floor price?**
- **If so, how would retailers and customers share the risks as well as benefits from any short-term price fluctuations in wholesale energy costs?**
- **Are there any other factors the Authority should consider in relation to this issue?**

3.4 Accounting for Energy Losses

Energy losses refer to the energy that is lost due to electrical resistance as energy flows through the transmission and distribution networks. As retailers record energy consumption at the customer's meter but are billed for the energy sent out from the generator, energy losses vary for each retailer and are calculated by combining transmission and distribution losses. The energy cost used in setting retail prices needs to account for these losses (the difference between total energy purchases and total sales).

AEMO calculates system loss factors for each NEM region and these are publicly available on its website. Distribution losses are approved and published by the AER.

In calculating energy costs for the BRCI, the Authority accounted for transmission losses, but not distribution losses, on the basis that its energy cost estimate was based on the NEM load

[8] IPART, *Final Report: Review of regulated retail tariffs and charges for electricity 2010-2013*, March 2010.
[9] ESCOSA, *2010 Review of Retail Electricity Standing Contract Price Path: Final Inquiry Report and Final Price Determination*, December 2010.
[10] ICRC, Final Decision: Retail Prices for Non-contestable Electricity Customers 2010-12, Report 7 of 2010, June 2010.
[11] ICRC, *Final Technical Paper: Model for determining the energy purchase cost of the transitional franchise tariffs,* Report 3 of 2010, March 2010.

which included distribution losses but excluded transmission losses. To account for transmission losses, the Authority increased energy cost estimates by the average loss factor published by Powerlink each year in its Annual Planning Report.

The Authority seeks stakeholder's views on any issues associated with the incorporation of energy losses in its energy cost estimate.

3.5 Cost of Meeting Obligations under Environmental Schemes

In establishing total energy costs for regulated retail tariffs, the costs incurred by retailers in meeting their obligations under State and Commonwealth Government greenhouse gas reduction schemes need to be accounted for. Currently, such schemes currently include the State Government's Queensland Gas Scheme and the Commonwealth Government's Enhanced Renewable Energy Target scheme.

Queensland Gas Scheme

The Queensland Gas Scheme was established to encourage the development of the State's gas industry and to reduce greenhouse gas emissions associated with the production of electricity in Queensland. The scheme commenced on 1 January 2005 and is legislated to expire on 31 December 2019.

Under the scheme, retailers are required to obtain and surrender sufficient Gas Electricity Certificates (GECs) to cover a proportion of their annual customer load. The proportion of annual customer load that GECs are required for is prescribed by the Queensland Government under the *Electricity Act 1994*. Retailers that fail to meet their annual GEC obligation 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.

GECs are created by accredited gas generators for each MWh of gas-fired electricity generated. The cost of GECs is effectively capped at the level of the shortfall penalty charge. However, the market prices of GECs are dependent on the interaction of the supply of, and demand for, GECs in the market. At present, direct market information on GEC prices is not publicly available.

To effectively estimate the future cost of compliance with the Queensland Gas Scheme, information is required for at least two variables:

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

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

The annual mandatory targets are prescribed under the *Electricity Act 1994*. In 2011, a retailer is required to obtain GECs for 15% of its annual electricity load. The Queensland Government has stated the mandatory target is set to increase to 18% by 2020.

In the absence of information from retailers about their actual GEC costs, the Authority has used different approaches to estimate costs. In BRCI decisions prior to 2011-12, the Authority estimated the cost of GECs based on the penalty price that retailers were likely to incur for not surrendering the required number of GECs in any one year.

In its most recent BRCI decision, the Authority used a market data based approach, based on AFMA market data. The Authority was of the view that this would provide a more accurate estimate of changes in a retailer's cost of acquiring GECs, as GECs have generally traded well below the penalty price and reliable market data was now available from AFMA.

An alternate approach would be to estimate GEC costs based on the LRMC of a gas-fired generation plant mix needed to meet retailers' demand for GECs over the determination period. A similar approach was adopted by IPART in its recent pricing determination to calculate the costs of the New South Wales Greenhouse Gas Abatement Certificates under its Greenhouse Gas Abatement Scheme (GGAS)[12].

In general, the Authority prefers using market data in estimating costs, as opposed to the use of proxies such as LRMC. An LRMC approach would be less transparent and potentially more complicated than a market-data based approach.

The Authority seeks stakeholders' views on the following:

- **How should a retailer's cost of complying with the Queensland Gas Scheme best be estimated?**
- **What data source(s) should the Authority use in modelling the Queensland Gas Scheme?**
- **Are there are any other issues that should be considered in estimating this cost component?**

Renewable Energy Target Scheme

In August 2009, the Federal Government expanded its Renewable Energy Target (RET) scheme by increasing the annual target of electricity to come from renewable sources from 2% (or 9,500 GWh) for each year from 2010 to 20% (or 45,000 GWh) by 2020[13]. The expanded scheme (ERET) affected retailers' wholesale energy purchase costs as it placed a greater obligation on them to create or purchase an increasing number of Renewable Energy Certificates (RECs). The ERET scheme commenced on 1 January 2011 and includes a Small-scale Renewable Energy Scheme (SRES) and a Large-scale Renewable Energy Target (LRET) scheme.

The SRES covers small-scale technologies such as solar panels and hot water installed by households and small businesses, and retailers have an obligation to purchase Small-scale Technology Certificates (STCs) based on expected rates of STC creation. The LRET sets annual targets for the amount of electricity that must be generated by large-scale renewable energy projects like wind farms. Retailers must purchase a set number of Large-scale Generation Certificates (LGCs) which is determined on the basis of achieving the annual target (currently 41,000 GWh by 2020)[14].

Retailers are required to surrender STCs and LGCs to fulfil their ERET obligations. As was the case with the previous RET scheme, if a retailer fails to meet its obligations, it will incur a penalty.

For the 2011-12 BRCI, the Authority based its estimate of 2011 LRET costs on weekly market prices for RECs, as published by AFMA, as well as the latest Renewable Power Percentage (RPP) and the latest annual LRET targets set by the Office of the Renewable Energy Regulator (ORER). In addition to this actual data, ACIL forecast its own estimate of total liable energy for 2012 and utilised the latest published LRET target to arrive at a forecast RPP.

[12] The Greenhouse Gas Abatement Scheme applies to New South Wales and operates in a similar manner to the Queensland Gas Scheme.
[13] See: http://orer.gov.au/legislation/reviews.html.
[14] Office of the Renewable Energy Regulator, *Increasing Australia's renewable energy generation: the Large-scale Renewable Energy Target (LRET) and the Small-scale Renewable Energy Scheme (SRES)*, April 2011.

To estimate SRES costs for the 2011-12 BRCI, the Authority relied on ORER's final Small-scale Technology Percentage (STP) published for 2011 and ACIL's STP estimate for 2012.

Some submissions received from retailers had suggested using the LRMC of renewable generation to estimate LRET costs. This approach would be somewhat similar to the approach used by IPART to estimate the costs of complying with the ERET scheme over its five-year determination period and the approach proposed by AGL SA in South Australia. However, the Authority rejected this suggestion as it preferred to utilise available market data rather than a proxy such as the LRMC.

The Authority seeks stakeholders' views on the following:

- **How should the Authority estimate retailers' costs of complying with the ERET scheme?**
- **What factors should be considered in forecasting the REC costs likely to be incurred by retailers in the SRES and LRET markets?**
- **Are there are any other issues that should be considered in estimating this cost component?**

Carbon Pricing

On 24 February 2011, the Commonwealth Government announced that an interim carbon price mechanism would apply as early as 1 July 2012. A carbon price is to be fixed at a pre-determined rate that increases each year for between three and five years, to be followed by the introduction of a carbon trading market.

If a carbon tax is implemented by the Commonwealth Government on 1 July 2012, the costs associated with this tax will be reflected in future contract prices and forecast spot prices and will therefore be accounted for in the energy purchase cost methodology outlined above. However, the Government has foreshadowed a range of compensation measures to accompany the introduction of a carbon tax, including assistance arrangements for households, communities and industry, and support for low emissions technology and innovation. Until the details of these measures are known, it is difficult to attempt to determine the most appropriate method for calculating carbon price compliance costs and any associated impacts on energy demand and supply. Nevertheless, to the extent that there is uncertainty around carbon/energy policy, this will have some impact on the current prices in the market and the cost of hedging.

The Authority seeks stakeholders' views on the following:

- **Is it reasonable to expect the market to effectively price in the carbon tax? If not, how should the Authority estimate retailers' costs of complying with a carbon price?**
- **What factors should be considered in forecasting future carbon price costs likely to be incurred by retailers?**
- **Any other issues?**

3.6 NEM participation fees and ancillary services charges

Retailers are required to pay NEM participation fees and ancillary services charges to AEMO. NEM participation fees include participant fees and FRC establishment and operation fees. These fees are levied by AEMO on participants in the NEM to cover the costs of operating the market. These fees are relatively stable as they are based on the operational expenditure of AEMO and are published on AEMO's website every financial year.

Ancillary services charges cover the costs of the services used by AEMO to manage power system safety, security and reliability. These fees are published by AEMO on its website on a weekly basis.

Given that changes in NEM participation fees and ancillary services charges are relatively stable from year to year, it seems reasonable to use historical data to forecast these costs.

In its BRCI decisions, the Authority forecast NEM fees based on trends in the fees since 2004-05 and forecast ancillary services costs based on the average of costs over the preceding year. IPART also forecast NEM costs and ancillary services costs based on historical trends in these costs, while the ICRC forecast NEM costs by adjusting costs in the previous year by CPI.

The Authority seeks stakeholders' views on the following:

- **How should the Authority estimate both the NEM participation fees and ancillary services charges incurred by retailers?**

- **Are there are any other issues that should be considered in estimating this cost component?**

4. RETAIL COSTS

4.1 Introduction

As indicated in Chapter 3, the Direction requires that the R component of each retail tariff should include appropriate allowances for energy and retail costs. This chapter discusses retail costs.

In the 2009 review, the Authority identified the following items for possible inclusion in the retail cost component: retail operating costs; customer acquisition and retention costs; and an allowance for retail margin. This chapter discusses the issues associated with each of these cost items, in particular:

(a) the characteristics of the retailer on which retail cost estimates are to be based and the market in which it operates;

(b) the costs to be included in the retail operating cost category and how these might be estimated;

(c) the role of customer acquisition and retention costs (CARC) and how these costs might be measured; and

(d) the role of retail margin and how an appropriate level of margin could be calculated.

4.2 Retailer Characteristics

Under the N+R approach, retail costs incorporate all the cost elements that would be incurred by an efficient retailer in supplying electricity to customers on each tariff.

The Authority considers that an efficient retailer is one that:

(a) minimises the costs of supplying electricity to customers;

(b) sets prices which are cost reflective; and

(c) earns a normal economic return that is expected to cover its cost of capital.

In determining the retailer costs to be included in the R component, a threshold question is whether the costs should be based on those incurred by an actual retailer or those likely to be incurred by a fictitious but representative retailer.

To date, under the BRCI approach to pricing, the Authority has been required to consider the retail costs for a representative retailer:

> ...based on an efficient entity carrying on an electricity retail business that meets all of the following criteria
>
> (a) it is carried on separately from any other business;
>
> (b) it has a significant market share of the State's electricity retail market;
>
> (c) it provides customer retail services to a cross-section of customers; and
>
> (d) it earns a reasonable retail margin.

Further, the representative retailer is assumed to have a proportion of customers within each tariff category that is substantially the same as the proportions for the whole Queensland customer base.

Regulators in other jurisdictions are required to set regulated prices for a single or small number of retailers and have tended to base their retail cost estimates on the costs of the actual retailer or retailers in question.

For example, in South Australia, ESCOSA determined the regulated prices to be charged by the incumbent retailer (AGL SA) based on AGL SA's actual retail costs[15]. In NSW, IPART determined the regulated prices to be charged by the three Standard Retailers (Country Energy, Integral Energy and EnergyAustralia) based on actual retail cost data provided by those retailers[16].

Unlike other jurisdictions, in Queensland, there is no Standard Retailer or retailer(s) from whom to readily source financial information upon which to base cost estimates. Therefore, determining costs on the basis of a representative retailer is likely to be more appropriate. An efficient, representative retailer may have a range of other characteristics which need to be considered, including:

(a) how well established the retailer is in the market (whether it is an incumbent or a new entrant);

(b) whether the retailer is a stand-alone business providing electricity retail services in Queensland or whether it is also involved in other activities or retails in other jurisdictions; and

(c) the size of the retailer's customer base.

Incumbent or New Entrant

The representative retailer's status as an incumbent or a new entrant will give rise to differing cost structures. For example, a new entrant retailer is likely to incur additional costs compared to an incumbent in marketing in order to acquire its customer base. An incumbent retailer will already have an established customer base which it will seek to maintain or enlarge.

A new entrant retailer is unlikely to have the same economies of scale as an incumbent retailer due to its smaller initial customer base over which to apportion fixed costs. As a result, retail costs incurred by a new entrant retailer are likely to exceed those of an incumbent retailer on a per customer basis.

In Queensland under the BRCI legislation, the representative retailer is defined as an incumbent retailer having a significant share of the Queensland electricity retail market.

In other jurisdictions, the choice of incumbent or new entrant has been determined either by the terms of reference for the pricing review or by the characteristics of the respective electricity markets.

For example, in setting regulated retail tariffs in New South Wales for 2007-10, IPART was required to consider the case of a "mass market new entrant" that was of sufficient size to

[15] ESCOSA, *2010 Review of Retail Electricity Standing Contract Price Path, Final Inquiry Report and Final Price Determination*, December 2010.
[16] IPART, *Review of regulated retail tariffs and charges for electricity 2010-2013, Final Report*, March 2010.

achieve economies of scale[17]. IPART considered that the representative retailer most likely to display these characteristics would be one that was an existing retail business with a large customer base outside NSW since this type of new entrant would be able to use its existing systems to enter the mass market in NSW. Conversely, in its 2010-13 Final Report, IPART interpreted the "standard retailer" within the terms of reference as being an incumbent retailer that had achieved economies of scale[18].

Stand-alone Retailer or Integrated Business

A further consideration is whether a representative retailer is a stand-alone retailer that only provides retail electricity services in Queensland or whether it also provides other services. For example, an integrated business may have energy retailing, distribution, generation, or dual fuel interests within Queensland or outside the state. An integrated business can spread some of its fixed and common retail operating costs (including overheads) over other business activities whereas a stand-alone business cannot. Therefore, an integrated business would generally have lower average costs than a stand-alone business as a result of greater economies of scale and/or scope.

To date, under the BRCI legislation, the Authority has been required to consider the costs of a stand-alone representative retailer based in Queensland.

In its 2010-13 Final Report, IPART interpreted the "standard retailer" referred to in its terms of reference for the review as a stand-alone retailer in New South Wales (NSW) that was not vertically integrated into electricity distribution in NSW but served retail customers, including small retail customers, in NSW and other jurisdictions across the NEM.

In South Australia and the ACT, tariffs are set for the single existing incumbent retailer (AGL SA in South Australia and ActewAGL in the ACT). These retailers are integrated businesses and hence are likely to have costs that reflect this.

Size of Retailer

If the representative retailer is deemed to be an incumbent retailer, it is also relevant to consider its scale of operations. In a competitive market environment, a retailer with a large number of customers can spread its fixed costs over a wider customer base than a smaller retailer, implying that average costs of a larger retailer would be lower than its competitors.

Under the BRCI legislation applying in Queensland to date, the Authority was required to consider the costs of a representative retailer that has a significant and representative share of the State's electricity retail market.

In a report to IPART for its 2007-10 retail tariff review, Frontier Economics found that standard electricity retailers in NSW, which ranged in size from around 700,000 to around 1.4 million customers, had similar costs per customer, suggesting that all businesses had captured any available economies of scale[19]. Frontier Economics also reported that smaller retailers such as Victoria Electricity, with around 100,000 customers, were successfully competing in the market, suggesting economies of scale were able to be achieved with relatively low customer numbers. However, this analysis did not take into account that Victoria Electricity (now operating as

[17] 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.
[18] IPART, *Review of regulated retail tariffs and charges for electricity 2010-2013, Final Report*, March 2010.
[19] Frontier Economics. *Mass Market New Entrant Retail Costs and Retail Margin, Prepared for the Independent Pricing and Regulatory Tribunal*, March 2007.

Lumo Energy) also had a significant customer base in other states and was thus able to take advantage of wider economies of scale.

In Queensland, a range of small and large retailers co-exist in the small customer market with customer numbers ranging from as low as 500 customers to well over 500,000.

The Authority seeks stakeholders' views on the following:

- **Should the build-up of retail costs be modelled on a representative retailer or an actual retailer in the Queensland market?**
- **Where a representative retailer is preferred:**
  - **Should it be a new entrant or incumbent in the market?**
  - **Should it be a stand-alone business providing only electricity retail services in Queensland or an integrated business involved in other activities including retailing in other jurisdictions?**
  - **How many customers should it be assumed to have?**
- **Where an actual retailer is preferred, which retailer(s) should be included?**

4.3 Retail Operating Costs

Retail operating costs relate to the costs of the services provided by an electricity retailer to its customers. In order to establish a retail operating cost allowance, the Authority needs to determine appropriate retail operating cost categories and an approach to estimating costs in each of those categories.

Retail Operating Cost Categories

The Authority noted in its 2009 review that retail operating costs typically include customer administration (including call centres), billing and revenue collection, IT systems, regulatory compliance, and possibly also those costs associated with metering and data services that are not already included in distribution charges.

While regulators in other jurisdictions have included similar retail operating costs, they differ on how costs are disaggregated or classified. For example, IPART, in its 2010-13 retail pricing determination, included six retail operating cost categories, namely[20]:

(a) call centre costs;

(b) customer information costs;

(c) corporate overhead costs;

(d) administrative costs associated with regulatory compliance;

(e) billing and revenue collection costs; and

(f) bad and doubtful debt.

[20] IPART, *Review of regulated retail tariffs and charges for electricity 201-2013, Final Report,* March 2010.

In Queensland under the BRCI, the Authority was required to consider the following cost categories:

(a) billing;

(b) customer call centres;

(c) credit management;

(d) energy trading activities;

(e) corporate overheads, including, for example, treasury functions, human relations and facilities management;

(f) information technology systems; and

(g) any other cost category the Authority considered reasonable.

Frontier Economics[21] and NERA Economic Consulting[22] have previously noted that some costs and risks could reasonably be included in either the allowance for retail costs or the allowance for retail margin. They argued that the choice should not materially affect the results of a price review, providing a consistent approach is adopted and no cost is omitted, or counted twice.

There are two main costs that have received different treatment across jurisdictions and over time. These are CARC (discussed below) and depreciation (discussed below in the context of the retail margin). In their most recent determinations, ESCOSA[23] and the Authority[24] incorporated CARC into the retail operating cost allowance, whereas IPART[25] and the Authority (prior to 2011-12) each considered CARC as a separate element of retail costs.

Currently, IPART[26], ICRC[27], ESCOSA[28] and the Authority under the BRCI, all include depreciation within their calculations of retail margin. IPART included depreciation in retail operating costs for its 2004-07 review.

The Authority seeks stakeholders' views on which costs should be included in the retail operating cost allowance and how they would best be categorised?

Calculating Retail Operating Costs

There are two generally accepted approaches to estimating retail operating costs. 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.

[21] Frontier Economics, *Electricity Retail Market Review – Electricity Tariffs, Draft Recommendations Prepared for the Western Australia Office of Energy*, April 2008.
[22] NERA Economic Consulting, *Approach to Estimating the Retail Margin and Retail Costs for a Mass Market New Entrant, Integral Energy – Final Report*, September 2006.
[23] ESCOSA, *2010 Review of Retail Electricity Standing Contract Price Path, Final Inquiry Report and Final Price Determination*, December 2010.
[24] QCA, *Final Decision, Benchmark Retail Cost Index for Electricity: 2011-12*, May 2011
[25] IPART, *Review of regulated retail tariffs and charges for electricity 201-2013, Final Report*, March 2010.
[26] IPART, *Review of regulated retail tariffs and charges for electricity 201-2013, Final Report*, March 2010.
[27] ICRC, *Final Decision, Retail Prices for Non-contestable Electricity Customers 2010–2012*, June 2010.
[28] ESCOSA, *2010 Review of Retail Electricity Standing Contract Price Path, Final Inquiry Report and Final Price Determination*, December 2010.

Under the BRCI methodology, the Authority estimated retail operating costs 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. For the 2011-12 BRCI, the Authority incorporated some additional costs into its retail operating cost estimate, including the additional costs associated with the Authority's regulatory fees and the customer acquisition costs, which had previously been calculated separately.

For its 2010-13 review, IPART adopted a bottom-up approach to estimating retail operating costs based on cost information provided by the NSW 'Standard Retailers'. It then benchmarked this estimate against its past determinations, regulatory decisions in other jurisdictions and cost information disclosed by publicly listed retailers.

ESCOSA adopted a similar approach for its 2011-14 review, which included an assessment of AGL SA's actual costs combined with benchmarking. ESCOSA then determined a cost-reflective price for the start of the price path, which would then be adjusted in subsequent years in line with movements in market contract prices (subject to prices sitting within a floor and ceiling).

While the Authority's benchmarking approach has been reasonably well accepted by stakeholders in the past, the Authority is open to considering alternative approaches. For instance, costs could be established through a bottom-up analysis of the retail operating cost components. However, as discussed earlier, given that there is no 'Standard Retailer' in Queensland from whom to source cost information upon which to base cost estimates, costs would need to be established for a representative retailer. One option would be to obtain (on a confidential basis) cost information from one or more retailers that best meet the representative retailer definition. Another approach would be to ask retailers to provide an estimate of the costs likely to be incurred by the representative retailer, rather than providing cost information relating to their own business. This cost structure could then be benchmarked against information from other jurisdictions. The Authority acknowledges that there may be some problems with benchmarking, such as the differing treatment of CARC and depreciation as mentioned above.

The Authority seeks stakeholders' views on the following:;

- **How should retail operating costs be calculated?**
- **What information should be obtained from retailers?**
- **What other sources of information would assist the Authority in its task?**

Customer Acquisition and Retention Costs

CARC are those costs incurred by retailers to acquire new customers and retain existing customers and generally include costs associated with marketing, advertising and sales overheads.

The size of the CARC allowance and how it is measured depend on the nature of the retailer and the market circumstances it faces. For example, if the representative retailer is defined as a new entrant to a newly contestable market the CARC allowance may need to recognise that the retailer will have to acquire customers and compete in the market.

Alternatively, if the representative retailer is defined as an incumbent retailer in a well established market, it would have an established brand and customer base to retain, which would require a lower CARC since the cost of retaining existing customers is likely to be significantly less than the cost of acquiring new customers[29].

There are a number of approaches that have been used by regulators to calculate CARC, including:

(a) the customer churn approach[30];

(b) the loss of scale approach[31]; and

(c) the expected customer 'life' approach[32].

CARC incurred by an incumbent retailer in a reasonably well developed market like South East Queensland is likely to a more stable outlay associated with the day-to-day marketing requirements of the business. In this situation, CARC is more likely to be treated as just another operating cost rather than calculated as a separate cost item. This approach has been used by ESCOSA[33] and the Authority[34].

The Authority seeks stakeholders' views on the following:

- **Should CARC be treated the same as other retail operating costs?**
- **If not, how should CARC be calculated?**
- **Are there any other issues related to CARC the Authority should consider?**

4.4 Retail Margin

The Direction requires the R component to include an allowance for retail costs that are reflective of the costs of supplying electricity to customers.

The retail margin represents a normal retail cost which reflects 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 investment and the risks they incur leads to under-investment by existing retailers, deters entry into the market by new retailers and stalls the development of efficient competition.

In the 2009 Review, the Authority proposed that the retail margin should be determined having regard to a number of factors, including a measurement of the risks faced by retailers and possibly benchmarking against the retail margins accepted in other jurisdictions.

[29] ESCOSA, *Competition in South Australia's Retail Energy Markets - Report on Interviews with Participants*, June 2010.
[30] IPART, *Review of regulated retail tariffs and charges for electricity 2010-2013, Final Report*, March 2010.
[31] ESCOSA, *Inquiry into Retail Electricity Price Path, Final Report*, March 2005.
[32] 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.
[33] ESCOSA, *2010 Review of Retail Electricity Standing Contract Price Path, Final Inquiry Report and Final Price Determination*, December 2010.
[34] QCA, *Final Decision, Benchmark Retail Cost Index for Electricity: 2011-12*, May 2011.

What Costs should be included in the Retail Margin?

To be cost reflective, the retail margin needs to be set so that it appropriately addresses the risks incurred by a retailer. The general classes of costs that could be covered by the retail margin include the following.

Return on Capital

Regulators typically make an allowance for the overall return on capital either explicitly in the retail margin (IPART 2010, ESCOSA 2007) or implicitly through benchmarking their retail margin to other jurisdictions which provide an allowance in their margin calculations. However, as noted by NERA in a report for Integral Energy, it is not always apparent what the overall return on capital comprises[35]. A return on capital may include a return on the retailer's physical assets, such as billing systems, and call centres. It can also include the return on working capital. This recognises the fact that electricity retailers generally recover their revenue in arrears whereas their costs are paid on much shorter terms.

Depreciation (Return of Capital)

Depreciation of the asset base has been accommodated by jurisdictions in two different ways. It has either been included as a line item in the retail operating cost allowance or, more recently, within the retail margin. For instance, IPART's 2004-07 Final Report included depreciation as a line item within retail operating costs rather than in the margin. However, in its 2007-10 and 2010-13 Final Reports, depreciation is included in the margin and excluded from retail operating costs. The implication, as noted by Frontier Economics, is that it makes benchmarking problematic if different jurisdictions are not including the same variables within their accepted retail margins[36].

Systematic Risks (Price and Volume)

Systematic risks are the result of exposure to overall economic or market conditions. Both price risk and volume risk have a systematic component. For instance, there is a relationship between customer usage and general economic conditions. Since the average price for energy is based on a historic load shape, a difference between historic and actual load could imply that the retailer faces the risk of a higher average purchase cost. This would be an example of volume risk.

Systematic price risk becomes a factor when there is volatility in wholesale spot and contract energy prices due to changes in economic conditions and demand. This may generate actual purchase costs which are different from those that were assumed when the regulated tariffs were set.

IPART's 2010-13 Final Report made an allowance for systematic risks in the retail margin. This was to compensate retailers for:

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

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

[35] NERA Economic Consulting, *Approach to Estimating the Retail Margin and Retail Costs for a Mass Market New Entrant, Integral Energy – Final Report*, 5 September 2006.
[36] Frontier Economics, *Mass Market New Entrant Retail Costs and Retail Margin*, Prepared for the Independent Pricing and Regulatory Tribunal, March 2007.

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

By contrast, ESCOSA’s 2007 Final Inquiry Report argued that energy trading risk was better addressed through its wholesale electricity cost (WEC) allowance rather than through the retail margin. Notably, its margin was expressed as a percentage of WEC + retail operating costs (ROC) so the decision to include a certain type of risk in one category rather than another does not impact on the overall size of the retail margin. ESCOSA found that a margin of 10% of WEC + ROC was approximately equal to the retail margins of 5% of sales revenue which were used elsewhere.

Under the BRCI pricing regime in Queensland, the Authority considered what retail margin would be sufficient to compensate retailers for their capital investments and exposure to systematic risks (price and volume risk). For the 2007-08 BRCI, the Authority concluded that a (gross) retail margin of 5% of total costs appeared appropriate by reference to retail margins accepted in other jurisdictions. The 5% margin was maintained for all subsequent BRCI decisions.

The Authority seeks stakeholders’ views on:

- **What factors should be considered when calculating an adequate retail margin?**

- **What level should the retail margin be set at?**

5. SETTING THE R COMPONENT OF RETAIL TARIFFS

5.1 Introduction

The Direction requires the Authority to investigate and report on an alternative set of retail electricity tariffs, based on an N+R approach, which could be applied for the period 1 July 2012 to 30 June 2013. As discussed in chapter 2, under the N+R approach, retail tariffs need to be aligned with distribution network tariffs. As a result, the number and structure of regulated retail tariffs will mirror Energex's network tariffs (the N component of retail tariffs). This chapter discusses the setting of an appropriate retail or R cost component of retail tariffs (comprising energy and retailer costs) which will apply to each network tariff.

Retail or R costs typically comprise around 50% of the total cost of providing electricity to households, with energy costs comprising around 40% and retailer costs around 10%. In determining an appropriate R component for each retail tariff, the Authority must determine how total energy and retailer costs (as discussed in chapters 3 and 4) are to be recovered from the customer groups to which the approved network tariffs apply.

The key to setting efficient tariffs is ensuring that they reflect the costs of supplying each customer group. These costs will vary depending on customers' consumption pattern (the level and timing of their consumption) and their geographical location, although differences in costs due to geographical location tend to be more relevant when considering the N cost component than in the case of the R cost component.

While the Direction acknowledges that retail tariffs must reflect the costs of supply for the retail electricity market and directs the Authority to consider setting tariffs on a cost-reflective basis, it also directs the Authority to consider a number of issues which could result in some tariffs not reflecting the cost of supply. However, as discussed in section 2, if some customers are to be supplied at subsidised rates (for example, under the Rural Subsidy Scheme) the extent of the subsidy would be best determined and enshrined at the network level. To the extent possible, the Authority's considers that the R component of tariffs should be set on a fully cost-reflective basis.

In order to ensure that retailers recover their efficient costs of providing retail electricity services, the R component of retail tariffs must be set cover the overall R costs. However, in order to encourage the efficient use of electricity, individual retail tariffs must also be cost reflective. This involves two key steps:

(a) allocating R costs (in aggregate) to each customer group based on the driver of those costs; and

(b) recovering those allocated R costs through retail tariffs that reflect the manner in which they are incurred by retailers.

5.2 Allocating R costs to customer groups

A necessary condition for cost-reflective pricing is that costs are recovered from each customer group on the basis of the driver or cause of the cost. In order to ensure alignment with network tariffs, R costs will need to be allocated to each customer group to which the approved network tariffs apply.

The cost of supplying energy to a particular group of customers will depend on the load profile of that customer group. For example, the costs to retailers of supplying customers with a peakier load profile will be different from the costs of supplying customers who have a flatter load profile. In order to allocate energy costs to reflect these cost drivers, the Authority will have to rely on Energex data on the load profiles for its various tariff groups. However, there may also be arguments for pursuing a simpler cost allocation approach.

Some costs are not directly attributable to the provision of services to any one particular customer group but are incurred to provide services to several customer groups together. These are known as common or shared costs and they must be allocated across tariff classes in some manner. There are a number of possible options for this purpose, including allocating costs to each customer group on the basis of the number of customers or on the aggregate level of consumption by that customer group.

The Authority seeks stakeholders' views on the following:

- **How should the Authority allocate R costs to each customer group?**
- **What information will the Authority require?**
- **What other issues should the Authority be aware of?**

5.3 Recovering R Costs through Individual Retail Tariffs

Aligning the tariff structure with the underlying cost structure should lead to more efficient use of electricity because customers will pay for the costs they cause an efficient retailer to incur. This approach also has the benefit of reducing retailers' risk, since a change in consumption will be offset by a change in costs. Nevertheless, given that electricity is an essential service, demand for electricity tends to be relatively inelastic (consumption does not change very much when price changes). Therefore, efficiency improvements from improving cost reflectivity in tariffs may be relatively low.

Determining the Fixed and Variable R Components

Energy Costs

Retailers purchase their electricity from the spot market and pay the spot market price (on a dollars per MWh basis) to AEMO. The spot price varies on a half hourly basis depending on supply and demand conditions and transmission constraints that exist at the time. This can lead to price volatility, including very high prices during periods of high demand (such as very hot days). This also suggests that retail tariffs should be higher at peak times and lower at off-peak times.

However, as discussed in chapter 3, retailers are generally able to manage the risk of price variability and very high spot prices by locking in a fixed price for a defined period (for example, three months or one year), quantity of electricity and load profile (for example, flat or peak), through the purchase of risk management or hedging contracts. The most regularly traded products are 'swaps', 'futures' and 'caps'. Given that the amount of exposure a retailer has to spot market prices depends on its hedging strategy, the manner in which a retailer incurs its costs may not (or need not) necessarily reflect movements in spot prices.

This leads to the question of whether energy costs are in fact fixed or variable and hence how they should be reflected in the fixed and variable components of retail tariffs. In its review of retail electricity tariffs for 2010-13, IPART considered energy costs to be 100% variable.

While energy costs may be largely variable if a retailer purchases electricity through the spot market, they may be largely fixed (for a period of time at least) if hedging contracts are used extensively. This is because a price is locked in for a certain quantity of electricity for a specified period of time. One option then would be to reflect energy costs in the variable component because it signals to consumers the cost of their consumption. An alternative would be to reflect energy costs in the fixed component of tariffs, to reflect the way the costs are largely incurred by retailers.

Retailer Costs (Retail Operating Costs Plus Retail Margin)

Determining the appropriate split between fixed and variable costs for retailers requires separate consideration of each individual retail operating cost. This approach may prove difficult to implement given the level of detail and information required.

An alternative approach would be to assume that retail operating costs have an overall fixed and variable split, as IPART did in its 2010-13 review. IPART set retail operating costs (excluding CARC) as 75% fixed and 25% variable and it considered CARC to be a fully fixed cost.

The determination of the appropriate split in Queensland is not necessarily straightforward. While IPART based its decision on actual reported data from Standard Retailers, the use of actual data may be more problematic in Queensland given that there is no Standard Retailer. While the Authority might be able to collect this data from retailers, it would still have to determine how this actual data translates into the cost split of a representative retailer, since the actual outcome is likely to be different for each retailer.

Alternatively, evidence from other jurisdictions could be used to arrive at a benchmark fixed/variable cost split. However, this too has its problems as benchmarking does not take account of differences in the operating environments of the retailers in the various jurisdictions. Therefore, a benchmarked fixed and variable cost split may not reflect the cost split of a representative Queensland retailer.

Finally, the retail margin is not a cost that is ‘incurred’ as such, but rather is intended to compensate retailers for the risk of retailing electricity in Queensland. In its 2010-13 review, IPART considered that the retail margin was a fully variable cost.

Time-of-Use Tariffs

For those network tariffs that include a time-of-use component, a time-of-use R component will have to be determined based on the load profiles of customers during the relevant periods of the day. For those network tariffs that do not include a time-of-use component, it will not be possible to reflect any costs incurred on a time-of-use basis, even if retailers incur their costs in this manner.

The Direction requires that the Authority consider the establishment of a voluntary time-of-use tariff for domestic customers (something the Authority recommended in its 2009 Review). However, as there is currently no data upon which to determine the likely uptake of such a tariff or the likely load profiles of customers exercising such an option, it raises the question as to how best to determine what the regulated time-of-use tariff should look like (how many time periods during a day) or the associated costs to allocate. One option would be for the regulated time-of-use tariff to be fairly broad, based around broad bands of time and clearly identified peak periods. Retailers may then be prepared to offer more adventurous market contracts for time-of-use with greater price variability.

The Authority seeks stakeholders’ views on the following:

- **How should the proportions of fixed and variable energy costs be determined?**
- **How should the proportions of fixed and variable retail costs (operating costs and margin) be determined?**

- **How should the Authority establish a time-of-use R component for residential customers with appropriate metering?**
- **How should the Authority set the R component for customers with accumulation meters?**
- **What information will the Authority require to set the R component of each tariff?**
- **What other issues should the Authority be aware of?**

5.4 Transitional issues

The Direction requires the Authority to consider transitional arrangements for customers on obsolete and declining block tariffs (since they will be removed from 1 July 2012) and customers on farming and irrigation tariffs who may be required to move from one tariff to another. Considering transitional arrangements for customers more generally may also be important, particularly where customers are likely to be significantly impacted by moving to new retail tariffs.

The Authority considers that an important aspect of introducing new tariffs is ensuring that customers are provided with sufficient information and time to make informed decisions about the impact of their electricity usage on their bills. Unfortunately, the reporting requirements established in the Direction will limit the available time for customers to digest the implications of tariff changes.

Depending on the extent of change, it may be appropriate to provide additional time for those customers who are required to change tariffs to make their decisions while ensuring that no new customers have access to old tariffs which are being replaced.

Customers that are currently supplied under tariffs that are not cost-reflective could also face significant price increases if they are immediately moved to a cost-reflective tariff. This requires a balance to be struck between the efficiency benefits of achieving cost reflective tariffs and the need to protect customers from price shocks. An option might be to transition to non-cost reflective prices. While this would assist those whose prices might otherwise have increased further, it could also deny benefits to those whose prices should have decreased more rapidly.

The Authority seeks stakeholders' views on the following:

- **Given that prices will only be determined for one year at a time, how could the Authority mitigate the impact on customers of moving to new tariffs?**
- **Is there any justification for determining prices for any customers on a less than cost-reflective basis in the first year?**

6. DEALING WITH UNCERTAINTY

In the 2009 Review, the Authority considered a number of other issues that would need to be addressed in the context of the then proposed multi-year pricing regime. It was recognised that the regulatory pricing framework would need to be sufficiently flexible to address the risk of under- or over-estimating costs (particularly energy costs) and to manage major changes which might arise during the pricing period.

The Direction that the Authority received does not include a multi-year pricing approach and, therefore, many of the issues discussed in the 2009 Review do not arise.

However, there remains the possibility that, even in a single-year pricing period, there may be major changes which may need to be accommodated by amending retail prices. For example, on 1 January 2010, substantial changes were made by the Commonwealth Government to its RET scheme. As a consequence of those changes, retailers incurred higher energy costs from 1 January 2010. However, in Queensland under the BRCI legislation, regulated prices were not able to be amended during the 2010-11 pricing period to reflect this increased cost, nor were the higher costs incurred in the last six months of 2010-11 able to be recognised in setting 2011-12 regulated prices.

Retailers supplying non-market customers simply had to absorb these higher costs for those customers for the six months in question.

While not a common occurrence by any means, it would be appropriate to consider whether and how such events should be able to be accommodated with the regulated price setting process.

6.1 Accounting for unforeseen events

Regulators setting multi-year price paths often include cost pass-through mechanisms to account for the impact of certain clearly defined events that lead to a material and unforeseen change in retailers' costs. Given the difficulty of assessing the probability of such events occurring and/or their impact on costs, and the fact that such events are generally beyond a retailers' control but may impose material costs or benefits on them, regulators have preferred for retailers to share some of the risk of these events occurring with customers rather than including a risk allowance in the retail margin.

Cost pass-through mechanisms tend to be included where a price path is longer than one year as forecasting becomes more difficult the longer the price path. Adjusting prices too frequently may result in excessive administration costs, increase price uncertainty for consumers and prevent retailers from managing risk.

An alternative approach would be to adjust tariffs in the forthcoming year to account for cost impacts from the previous year.

Under any proposal, it would only be necessary for the Authority to account for impacts on the R component of tariffs as cost pass-through arrangements administered by the AER are already in place for the network operators.

As noted above, in setting prices under the BRCI, the Authority was required to determine the total costs for the forthcoming tariff year by estimating the costs of supplying customers during that year. The legislative framework did not allow for the Authority to account for the impact of unforeseen events on costs.

In its 2010-2013 determination[37], IPART included a cost pass-through mechanism which allowed retailers to pass through to customers the incremental, efficient costs associated with defined regulatory or taxation change events that met a materiality threshold. However, the mechanism is symmetrical, meaning that IPART may also adjust tariffs downwards to reflect cost decreases. Examples of the types of events covered under these arrangements are changed obligations in relation to green energy schemes, unforeseen AEMO changes (such as a reserve trader or direction event) and retailer of last resort (ROLR) events.

Other regulators, including ESCOSA in South Australia[38] and the ICRC in the ACT[39] also include cost pass-through mechanisms in their regulated retail price determinations.

The Authority seeks stakeholders' views on the following:

- **Is a mechanism required to account for the impact of unforeseen events on the R component of retail tariffs?**
- **If so, should the mechanism apply to both the retail operating cost and energy cost components or just the more volatile energy cost component?**
- **What specific events should be included or excluded?**
- **Should a materiality threshold apply? If so, how should it be determined?**
- **What other issues should the Authority be aware of?**

[37] IPART, *Review of regulated retail tariffs and charges for electricity 2010-2013, Final Report*, March 2010.
[38] ESCOSA, *2010 Review of Retail Electricity Standing Contract Price Path, Final Inquiry Report and Final Price Determination*, December 2010.
[39] ICRC, *Final Decision, Retail Prices for Non-contestable Electricity Customers 2010-2012*, June 2010.

APPENDIX 1 – DIRECTION AND COVERING LETTER

Hon Stephen Robertson MP
Member for Stretton

Queensland Government

Minister for Energy and Water Utilities

MBN4614
11 MAY 2011

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

Dear Mr Parmenter

I refer to the Queensland Competition Authority's (the QCA) findings of its *2009 Review of Electricity Pricing and Tariff Structures*. In particular, I refer to the QCA's recommendation that an alternative price-setting methodology be implemented based on a Network (N) + Retail (R) (N+R) cost build-up (building block) approach to setting notified prices, and that the regulated retail tariffs be structured to reflect the major causes or drivers of the costs of supplying electricity to customers.

The Government has considered the QCA's recommendations and has decided to implement a new electricity pricing methodology based on a cost-reflective N+R approach and establish a new set of regulated retail tariffs that are aligned with the network tariffs.

Attached is a Direction under section 10(e) of the *Queensland Competition Authority Act 1997* requiring the QCA 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.

In undertaking this Direction, the QCA should note the following:

- All retail tariffs should be aligned with the relevant network tariff;
- To ease the pressure on low consumption customers, the Government has endorsed the establishment of an inclining block network tariff for domestic customers to apply from 1 July 2012;
- It is the Government's intention that any obsolete and declining block tariffs be removed from the tariff schedule from 1 July 2012;
- Before making any changes to farming and irrigation tariffs, the QCA is required to undertake consultation with relevant stakeholders and industry groups and consider the impacts;

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- It is the Government's intention that from 1 July 2012, all large 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 move to a market contract; and
- As the retail electricity market for street lighting in south east Queensland has already been deregulated, the regulated tariff for electricity supplied to street lights will apply to customers in Ergon's network area only. Following the Australian Energy Regulator's reclassification of street lighting services for the 2010-2015 distribution regulatory period, the Government will consider whether any further changes to this tariff may be appropriate.

Consistent with the Direction, the QCA is required to undertake an open consultation process with all relevant parties and consider all submissions received.

The QCA must provide a Draft Report to Government in March 2012, with a Final Report required by 31 May 2012.

Amendments to the *Electricity Act 1994* (the Act) and the *Electricity Regulation 2006* will be required to ensure the process and intent reflected in the Direction will be deemed sufficient for the purposes of the tariff setting process prescribed under the Act. It is the Government's intention to progress the necessary legislative amendments at the earliest possible opportunity.

The Queensland Government is concerned about the pressure that rising electricity costs are placing on household budgets. In this context, government would like to ensure the QCA is aware of this issue for Queensland consumers.

If you have any questions about my advice to you, Ms Kathie Standen, A/General Manager, Energy Industry Policy of the Department of Employment, Economic Development and Innovation will be pleased to assist you and can be contacted on telephone 322 58256.

Yours sincerely

[redacted]

STEPHEN ROBERTSON MP

Att

QUEENSLAND COMPETITION AUTHORITY ACT 1997
Section 10 (e)

MINISTERS' DIRECTION NOTICE

In my capacity as both 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*, I hereby direct the Queensland Competition Authority (the QCA) 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, in accordance with this Direction Notice.

1. Matters to be considered

Queensland electricity consumers should, wherever possible, have the opportunity to benefit from competition and efficiency in the market place. In order to meet Queensland's responsibilities under the National Competition Policy reforms, the Queensland Government introduced full retail competition on 1 July 2007. For the retail electricity market to be successful, electricity prices must reflect the costs of supply.

In 2009, the Queensland Government directed the QCA to review the Benchmark Retail Cost Index (BRCI) methodology as set out in the *Electricity Act 1994*, and existing retail tariff structures, and consider whether adjustments may be necessary to ensure regulated retail electricity (notified) prices reflect the costs of supplying electricity to customers in Queensland.

The QCA recommended implementing a Network (N) + Retail (R) cost build-up approach to setting notified prices for each retail tariff, where the retail cost component (R) is regulated and the network cost component (N) is passed through to customers.

Consistent with this recommendation, the QCA is directed to investigate and 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.

In investigating and reporting on an alternative pricing methodology, the QCA should have regard to the following:

1.1 The N component

Network costs should be treated as a pass through to customers. The N cost component of each tariff should be equal to the approved ENERGEX network price for the relevant tariff year.

1.2 The R component

The R cost component of each tariff should include appropriate allowances for energy and retail costs.

In investigating and reporting on a possible alternative retail electricity pricing methodology and schedule of retail electricity tariffs, the QCA should have regard to the following:

- all tariffs (excluding those specified below) are to be cost-reflective;
- for farming and irrigation tariffs, targeted consultation should be undertaken with relevant stakeholders and industry groups and consideration given as to whether any transitional arrangements may be required for customers moving from one tariff to another;
- an appropriate tariff for customers who are supplied under the Rural Subsidy Scheme or are located in a drought declared area should be considered;
- consideration should be given to a voluntary cost-reflective time-of-use tariff for domestic customers;
- consideration should be given to an appropriate tariff for electricity supplied to continuously operating traffic signals installed on a road; and
- consideration should be given to transitional arrangements for customers who are on obsolete and declining block tariffs.

In reporting on a possible alternative schedule of retail electricity tariffs, the QCA should note the following:

- as at 1 July 2012, access to regulated tariffs will be removed for large non-residential customers in ENERGEX's network area who consume over 100 megawatt hours per annum;
- as at 1 July 2012, all obsolete and declining block tariffs will be removed from the tariff schedule and any customers on these tariffs will be required to transition to an alternative tariff;
- in relation to a voluntary time-of-use tariff for domestic customers, any customer who chooses to transfer to this tariff, providing they have the appropriate metering, will be permitted to transfer back to the standard regulated tariff for domestic customers at any time if they choose to; and
- seasonal tariffs are not to be considered.

2. Consultation

The QCA should undertake an open consultation process with all relevant parties and consider any submissions received.

3. Reporting

The QCA must provide:

a) a draft Report in March 2012; and

b) a final Report by 31 May 2012.

The QCA should publish issues papers, reports and submissions as it considers appropriate, including on its website.

4. Other matters

In investigating and reporting on a possible alternative retail electricity pricing methodology and schedule of tariffs, the QCA should not be constrained by the requirements of Division 3 of the *Electricity Act 1994*.

The QCA may exercise all the powers under Part 6 of the *Queensland Competition Authority Act 1997*.

[redacted]

RACHEL NOLAN

27 APR 2011

The Hon. Rachel Nolan MP, Minister for Finance and The Arts and
Acting Treasurer and Minister for State Development and Trade

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APPENDIX 2 – ENERGEX'S CURRENT (2011-12) NETWORK TARIFFS

Table 6.4 Proposed tariffs for DUOS and DPPC (TUOS) – standard control services

Tariff Class	Tariff Description	Network Tariff Code	DUOS Charges						DPPC (TUOS) Charges					
			Fixed ($/day)	Capacity ($/kW/ month)	Demand ($/kW/ month)	Volume (Energy (c/kWh)	Volume Peak (c/kWh)	Volume Off-Peak (c/kWh)	Fixed ($/day)	Capacity ($/kW/ month)	Demand ($/kW/ month)	Volume (Energy) (c/kWh)	Volume Peak (c/kWh)	Volume Off-Peak (c/kWh)
ICC	ICC	1000	Tariffs for ICC customers are confidential and are provided in Appendix 1.1.											
CAC – 33kV Line/Bus	CAC – 33kV Line/Bus	3500	Site specific (see Appendix 1.2)	0.941	2.254		0.139	0.014	Site specific (see Appendix 1.2)	0.000	1.047		0.126	0.126
CAC – 11kV Bus	CAC – 11kV Bus	4000		1.738	3.767		0.141	0.014		0.000	1.047		0.126	0.126
CAC – 11kV Line	CAC – 11kV Line	4500		2.463	4.969		0.169	0.017		0.000	1.047		0.126	0.126
EG	EG – 110kV	2000	Site specific (see Appendix 1.2)	0.039	0.109		0.325	0.032	Site specific (see Appendix 1.2)	0.000	1.047		0.126	0.126
	EG – 33kV	2500		0.941	2.254		0.139	0.014		0.000	1.047		0.126	0.126
	EG – 11kV	3000		2.463	4.969		0.169	0.017		0.000	1.047		0.126	0.126
SAC Demand	HV Demand	8000	37.12		7.436	0.175			9.40		1.493	1.187		
	Large Demand	8100	32.35		9.449	0.188			9.40		1.493	1.187		
	Medium Demand	8200	13.12		10.865	0.305			9.40		1.493	1.187		
	Small Demand	8300	1.32		12.155	0.854			1.63		1.493	1.187		
SAC Non-demand	Medium	8600	0.63			7.130			0.75			1.257		
	Medium TOU	8800	0.63				7.163	5.970	0.75				1.257	1.257
	Small	8500	0.27			7.353			0.06			1.471		
	Small TOU	8700	0.27				7.430	6.192	0.06				1.471	1.471
	Solar PV	9900	Government mandated tariff paid by ENERGEX to the customer											
	Domestic	8400	0.27			7.353			0.06			1.471		
	Controlled Load 1	9000	0.10			0.541			0.002			0.218		
	Controlled Load 2	9100	0.10			1.681			0.002			0.218		
	Street Lighting	9400				4.652						1.820		
	Watchman Lights	9500				4.652						1.820		
	Unmetered	9600				4.652						1.820		

Note: All tariffs are GST exclusive

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APPENDIX 3 – GAZETTE NOTICE 2011-12 RETAIL TARIFF SCHEDULE

TARIFF SCHEDULE

Note 1: For the purposes of ss. 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 non-market customers;
Part 5 applies to eligible non-market customers of Ergon Energy Queensland Pty Ltd. Eligible non-market customers 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.

Part 1

TARIFFS FOR DOMESTIC, COMMERCIAL AND RURAL APPLICATIONS

***Tariff 11* – Domestic (Lighting, Power and Continuous Water Heating) –**

This tariff is applicable to electricity supplied to domestic premises primarily for the personal use of the resident/s of those premises. Where premises are primarily operated as a business, including the provision of short stay accommodation of a holiday nature, Tariff 11 is not applicable.

This tariff is also applicable to electricity used in separately metered common sections of domestic premises consisting of more than one flat or home unit.

All Consumption	**20.69 c/kWh**
plus a Service Fee per metering point per month of	**$7.96**

Further applications of this tariff are described in Part 4 (Concessional Applications of Tariff 11).

***Tariff 20* – General Supply –**

This tariff shall not apply in conjunction with Tariff 21, 22, 62 or 63 at the same installation.

All Consumption	**23.19 c/kWh**
plus a Service Fee per metering point per month of	**$14.43**

***Tariff 21* – General Supply –**

This tariff shall not apply in conjunction with Tariff 20, 22, 62 or 63 at the same installation.

First 100 kilowatt hours per month	**28.80 c/kWh**
Next 9,900 kilowatt hours per month	**27.06 c/kWh**
Remaining kilowatt hours	**20.60 c/kWh**
Minimum Payment per month	**$12.90**

***Tariff 22* – General Supply – Time-of-Use –**

This tariff shall not apply in conjunction with Tariff 20, 21, 62 or 63 at the same installation.

For electricity consumed between the hours of 7.00 am and 9.00 pm, Monday to Friday inclusive -

All Consumption	**28.17 c/kWh**

For electricity consumed at other times -

All Consumption	**9.92 c/kWh**
plus a Service Fee per metering point per month of	**$31.79**

***Tariff 31* – Night Rate (Super Economy) –**

Applicable when electricity supply is permanently connected to apparatus or 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 switch-off. 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.

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.
The distribution entity will supply and maintain load control equipment at its cost.

All Consumption	**8.44 c/kWh**
Minimum Payment per month	**$5.54**

***Tariff 33* – Controlled Supply (Economy) –**

Applicable when electricity supply is:

(a) connected by means of a socket-outlet solely for the purposes of pool filtration and associated sanitation systems in domestic installations in a manner 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 -
      A. to arc or resistance welding plant and boosted heatbanks;

B. where the apparatus (except for refrigeration and non-boosted heatbanks) is duplicated in order that supply may be obtained on a different tariff for the same purpose in the periods during which supply is not available under this tariff.

The distribution entity will supply and maintain load control equipment at its cost. 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 **12.43 c/kWh**

Minimum Payment per month **$5.54**

***Tariff 37* – Non-Domestic Heating – Time-of-Use (Obsolescent) –**

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 **30.84 c/kWh**

For electricity consumed between the hours of 10.30 pm and 4.30 pm **12.33 c/kWh**

Minimum Payment per month **$5.27**

***Tariff 41* – Low Voltage General Supply Demand –**

Demand Charge –

$34.15 per kilowatt of chargeable demand per month.

Energy Charge –

All Consumption **7.18 c/kWh**

plus a Service Fee per metering point per month of **$48.65**

The chargeable demand in any month shall be -

(a) the maximum demand recorded in that month; or

(b) 60 percent of the highest maximum demand recorded in any of the preceding eleven months; or

(c) 75 kilowatts,

whichever is the highest figure.

'Demand' shall mean the average demand in kilowatts over a period of 30 minutes, as measured on the distribution entity's meters.

Customers taking supply under this tariff will not be supplied under any other tariff at the same premises.

***Tariff 43* – General Supply Demand – Time-of-Use**

Demand Charge –

$14.79 per kilowatt of chargeable demand per month.

Energy Charge –

For electricity consumed between the hours of 7.00 am and 11.00 pm Monday to Friday inclusive - **14.61 c/kWh**

For electricity consumed at all other times **5.84 c/kWh**

plus a Service Fee per metering point per month of **$48.65**

The chargeable demand in any month shall be -

(a) the maximum demand recorded in that month; or

(b) 60 percent of the highest maximum demand recorded in any of the preceding eleven months; or

(c) 400 kilowatts, whichever is the highest figure.

'Demand' shall mean the average demand in kilowatts over a period of 30 minutes, as measured on the distribution entity's meters.

Customers taking supply under this tariff will not be supplied under any other tariff at the same premises.

***Tariff 53* – High Voltage General Supply Demand – Time-Dependent –**

Supply voltage	11kV to33kV	66kV and above
Demand charge (\$/kW/month)	**32.35**	**31.20**
Night excess* demand charge (\$/kW/month)	**9.16**	**8.89**
Energy charge (c/kWh)	**6.80**	**6.61**

plus a Service Fee per metering point per month of **$125.82**

***Night Excess** for a billing month is the number of kilowatts by which the demand recorded outside the interval 7.00 am to 9.00 pm Monday to Friday inclusive exceeds the demand recorded within this interval in the month.

The minimum total demand charge applicable in any month shall be equivalent to 300 kilowatts charged at **$32.35** per kilowatt for voltages up to 33kV and **$31.20** per kilowatt for voltages at 66kV and above, or 60 percent of the highest charge at the rates applicable in accordance with the requirements of this tariff to the metered monthly demands for any of the preceding eleven months, whichever is the higher.

'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 taking supply under this tariff will not be supplied under any other tariff at the same premises.

Tariff 62 **– Farm – Time-of-Use –**

This tariff shall not apply in conjunction with Tariff 20, 21, 22 or 63 at the same installation.

For electricity consumed between the hours of 7.00 am and 9.00 pm, Monday to Friday inclusive –

First 10,000 kilowatt hours per month	**29.61 c/kWh**
Remaining kilowatt hours	**25.04 c/kWh**

For electricity consumed at other times -

All Consumption	**10.47 c/kWh**

plus a Service Fee per metering point per month of	**$15.20**

Tariff 63 **– Farm – Time-of-Use (Obsolescent) –**

No new customers will be supplied under this tariff. It is available only to customers taking supply under Tariff 63 at 26 March 1995.

This tariff shall not apply in conjunction with Tariff 20, 21, 22 or 62 at the same installation.

For electricity consumed between the hours of 7.00 am and 9.00 pm, Monday to Friday inclusive –

First 100 kilowatt hours per month	**52.53 c/kWh**
Next 9,900 kilowatt hours per month	**32.15 c/kWh**
Remaining kilowatt hours	**25.18 c/kWh**

For electricity consumed at other times –

All Consumption	**11.08 c/kWh**

Under this tariff, the required minimum annual consumption at 'other times' shall be 3,000 kilowatt hours. If the annual consumption at 'other times' is less than 3,000 kilowatt hours, the shortfall will be charged at the rate applicable at 'other times' at the time that the charge for the shortfall is being calculated.

Tariff 64 **– Irrigation – Time-of-Use (Obsolescent) –**

No new customers will be supplied under this tariff. It is available only to customers taking supply under Tariff 64 at 26 March 1995.
For electricity consumed in a fixed 12 hour daily pricing period (as agreed between the retail entity and the customer from the range 7.00 am to 7.00 pm; 7.30 am to 7.30 pm; or 8.00 am to 8.00 pm) Monday to Sunday inclusive –

All Consumption	**25.66 c/kWh**

For electricity consumed at other times -

All Consumption	**14.09 c/kWh**
Minimum Payment per month	**$13.60**

No alteration to the selected daily pricing period shall be permitted until a period of twelve months has elapsed from the previous selection.

Tariff 65 **– Irrigation – Time-of-Use –**

For electricity consumed in a fixed 12 hour daily pricing period (as agreed between the retail entity and the customer from the range 7.00 am to 7.00 pm; 7.30 am to 7.30 pm; or 8.00 am to 8.00 pm) Monday to Sunday inclusive –

All Consumption	**23.62 c/kWh**

For electricity consumed at other times -

All Consumption	**13.01 c/kWh**
plus a Service Fee per metering point per month of	**$15.20**

No alteration to the selected daily pricing period shall be permitted until a period of twelve months has elapsed from the previous selection.

Tariff 66 **– Irrigation –**

Annual Fixed Charge (in respect of each point of supply) - per kilowatt of connected motor capacity used for irrigation pumping **–**

First 7.5 kilowatts	**$24.01** per kW
Remaining kilowatts	**$72.19** per kW

plus

Energy Charge –

All Consumption **12.38 c/kWh**

plus a Service Fee per metering point per month of **$33.50**

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.

***Tariff 67* – Farm – Applicable only to customers supplied under the Rural Subsidy Scheme introduced in 1973.**

Annual Payment – An Annual Payment calculated in accordance with the provisions of the 1973 Rural Subsidy Scheme and as set down in the Rural Subsidy Scheme Agreement between the customer and the retail entity;

Plus

Energy Charge –

All Consumption **25.56 c/kWh**

Minimum Payment per month **$13.60**

***Tariff 68* – Irrigation Pumping in Drought Declared Area (Obsolete except for eligible customers of Ergon Energy Queensland Pty Ltd) –**

From 1 July 2008, Tariff 68 is only available to eligible customers of Ergon Energy Queensland Pty Ltd. Non-market customers of other retail entities taking supply under Tariff 68 at 30 June 2007 will be supplied under other tariffs appropriate to their installations.

Refer to Part 5 (Relief from Electricity Charges where Drought Declaration in Force) for details about the conditions, price and eligibility for Tariff 68.

Part 2

TARIFFS FOR UNMETERED SUPPLY INCLUDING PUBLIC LAMPS, TRAFFIC SIGNALS, WATCHMAN LIGHTING AND TEMPORARY SERVICES

***Tariff 71* – Public Lamps –**

Notified prices for Tariff 71, published in accordance with section 90 of the *Electricity Act 1994*, 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 which apply only to non-market customers.

Charge per lamp per annum						
Lamp category	Rate 1		Rate 2		Rate 3	
	Fixed cost	Per watt*	Fixed cost	Per watt*	Fixed cost	Per watt*
Mercury vapour	119.09	0.775	71.50	0.675	15.83	0.675
Mercury halide	181.64	0.718	108.98	0.675	15.83	0.675
Sodium vapour low pressure	136.09	1.121	85.17	0.675	15.83	0.675
Sodium vapour high pressure	140.62	0.796	81.77	0.675	15.83	0.675
Incandescent	238.29	0.775	192.82	0.675	15.83	0.675
Fluorescent	123.73	1.112	79.59	0.675	15.83	0.675

*The 'Per Watt' charge shall apply to the nominal wattage rating of the public lamp.

Rate 1 - Applicable where the capital costs of the installation are borne by the distribution entity.

Rate 2 - Applicable where the capital costs of the installation are not borne by the distribution entity.

Rate 3 - Applicable to installations such as freeway lighting where the capital and maintenance costs of the installation are not borne by the distribution entity.

Charges for incandescent lamps shall apply only in the following areas:

- the Capricornia and South West Regions of Ergon Energy Corporation Limited's Distribution Area; and
- ENERGEX Limited's Distribution Area.

***Tariff 81* – Traffic Signals – Continuously Operating –**

For electricity supplied to continuously operating traffic signals installed on a road –

$1.4852 per 10 watts (or part thereof) per installation per month.

***Tariff 91* – Watchman Service Lighting –**

For electricity supplied to Watchman Service Lighting

$0.6669 per 10 watts (or part thereof) per lamp per month.

This charge shall apply to the nominal wattage rating of each lamp.

Charges for installation, maintenance and removal of Watchman Service Lighting apply in addition to the above charge for electricity supplied.

Other Unmetered Supply

Unmetered electricity supply is available to other small loads, as approved by the distribution entity.

In general, this situation applies where the distribution entity considers it impractical to read or maintain a meter or where metering equipment would be susceptible to damage and includes, for example, supply to telephone boxes, illuminated signs, public amenities lighting, and Department of Defence, Department of Health or similar mobile facilities temporarily connected to the network.

Such supply is to be charged at general supply rates under Tariff 20, 21 or 22, as agreed between the customer and the retail entity, based on consumption determined by the distribution entity using the wattage and hours of operation agreed between the customer and 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.

Part 3

APPLICATION OF TARIFFS FOR CUSTOMERS ON NOTIFIED PRICES – GENERAL

Non-market customers 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.

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 to a customer, the customer may request the retail entity to arrange for the required meter to be installed at the customer's cost.

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.

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.)

The Service Fee applicable to all high voltage supply given at Tariffs 20, 22, 41 and 43 shall be **$125.82** and shall be applied after the application of the High Voltage credit.

(iii) Discounts where customer meets certain system costs

Where high voltage customers with recorded maximum demands in excess of 1,000 kilowatts meet certain costs of providing supply from the Powerlink Queensland connection point nearest to their installations, a discount of up to 9 percent may be applicable to the energy and demand charges otherwise assessed at the tariffs herein.

Upon written application by the customer the retail entity will evaluate the level of discount appropriate to the installation in question and will negotiate an agreement with the customer which will take effect from the date of written application.

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 premise 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 domestic customer is measured and charged by means of a card-operated meter:
   - (i) for Tariff 11 (Domestic – Lighting, Power and Continuous Water Heating), all consumption shall be charged at the 'All Consumption' rate (**20.69 cents/kWh**), plus a Service Fee of **$1.82** per week shall apply;
   - (ii) for Tariff 31 (Night Rate – Super Economy), all consumption shall be charged at the 'All Consumption' rate (**8.44 cents/kWh**), with no Minimum Payment; and
   - (iii) for Tariff 33 (Controlled Supply – Economy), all consumption shall be charged at the 'All Consumption' rate (**12.44 cents/kWh**), with no Minimum Payment.

(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) (**23.19 cents/kWh**), plus a Service Fee of **$3.30** per week shall apply.

Other Retail Fees and Charges

A retail entity may charge its non-market customers 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 TARIFF 11 (DOMESTIC)

***Tariff 11* – Domestic (Lighting, Power and Continuous Water Heating) is 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:

(A) Tariff 68 – Irrigation Pumping in Drought Declared Area

A customer of Ergon Energy Queensland Pty Ltd who is a farmer in a drought declared area or whose property is individually drought declared may transfer individually metered irrigation pumping loads to this tariff until the drought declaration is revoked: Provided that, if water pumping time restrictions continue to apply after the drought declaration is revoked, the customer may remain on this tariff until the water pumping time restrictions are lifted or until 12 months after the revocation of the drought declaration, whichever is the earlier.

All consumption	**19.00 c/kWh**

The conditions set out in Part 3, applicable to customers changing from one tariff to another, do not apply in the case of a customer who transfers individually metered irrigation pumping loads to or from this Tariff 68.

(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, including a transfer of irrigation pumping loads to Tariff 68, 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.

Non-market customers of other retail entities

Non-market 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.

Non-market customers of other retail entities taking supply under Tariff 68 at 30 June 2007 will be supplied under other tariffs appropriate to their installations.

BRISBANE
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