Queensland Competition Authority

Final Determination

Regulated Retail Electricity Prices 2013-14

May 2013

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GLOSSARY

2012-13 Determination	The Authority's determination of regulated retail electricity prices (notified prices) which applies from 1 July 2012 to 30 June 2013
2013-14 Determination	The Authority's determination of regulated retail electricity prices (notified prices) which applies from 1 July 2013 to 30 June 2014
ACIL	ACIL Tasman
ACIL Preliminary Draft Report	ACIL Tasman, *Estimated Energy Costs for Use in 2013-14 electricity retail tariffs – preliminary draft report*, December 2012 – can be accessed at www.qca.org.au
ACIL Draft Report	ACIL Tasman, *Estimated Wholesale Energy Costs for 2013-14 retail tariffs - draft report*, February 2013 – can be accessed at www.qca.org.au
ACT	Australian Capital Territory
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AFMA	Australian Financial Markets Association
AIR	Association of Independent Retirees
ASMC	Australian Sugar Milling Council
ATO	Australian Tax Office
Authority	Queensland Competition Authority
BRCI	Benchmark Retail Cost Index
BRIG	Bundaberg Regional Irrigators Group
BWEL	Bundaberg Walkers Engineering Limited
CAC	Connection Asset Customer
CARC	Customer Acquisition and Retention Costs
CCIQ	Chamber of Commerce and Industry Queensland
CEC	Clean Energy Council
CER	Clean Energy Regulator (formerly the Office of the Renewable Energy Regulator (ORER))
COAG	Council of Australian Governments

CPI	Consumer Price Index
CSO	Community Service Obligation
CQMS Razer	Central Queensland Mining Supplies Razer
Delegation	The Delegation from the Minister for Energy and Water Utilities, pursuant to section 90AA(1) of the *Electricity Act 1994*, directing the Authority to determine regulated retail electricity tariffs (notified prices) to apply from 1 July 2013 to 30 June 2016
DEWS	Department of Energy and Water Supply
EBITDA	Earnings before interest, tax, depreciation and amortisation
EECL	Ergon Energy Corporation Limited
EEQ	Ergon Energy Queensland
Electricity Act	*Electricity Act 1994*
Electricity Regulation	*Electricity Regulation 2006*
ERA	Economic Regulation Authority in Western Australia
ERAA	Energy Retailers Association of Australia
ERET	Enhanced Renewable Energy Target Scheme
ESAA	Energy Supply Association of Australia
ESCOSA	Essential Services Commission of South Australia
FRC	Full Retail Competition
GEC	Gas Electricity Certificate
GST	Goods and services tax
GWh	Gigawatt hours
HV	High voltage
ICC	Individually Calculated Customer
ICRC	Independent Competition and Regulatory Commission
Interim Consultation Paper	First consultation paper released, asking for views relevant to the Authority's task of determining regulated retail electricity prices (notified prices) to apply from 1 July 2013 to 30 June 2014
IPART	Independent Pricing and Regulatory Tribunal
kW	Kilowatt

kWh	Kilowatt hour
Large customer	A customer that consumes more than 100 MWh of electricity per year
LGC	Large-scale Generation Certificate
LRET	Large-scale Renewable Energy Target
LRMC	Long Run Marginal Cost
MDIA Council	Mareeba-Dimbulah Irrigation Area Council
Minister	Minister for Energy and Water Supply
MW	Megawatt
MWh	Megawatt hour
NECF	National Energy Customer Framework
NEM	National Electricity Market
NER	National Electricity Rules
Notified/regulated retail prices	The electricity prices that a retailer may charge its non-market customers, as defined under section 90 of the *Electricity Act 1994*
NSA	National Seniors Australia
NSLP	Net System Load Profile
OTTER	Office of the Tasmanian Economic Regulator
PCO	Pioneer Canegrowers Organisation
PPA	Power Purchase Agreement
Price Distribution Approach	A statistical model that estimates the price a retailer might be willing to pay to enter hedging contracts
PV	Photovoltaic
PVW	Pioneer Valley Water
QCOSS	Queensland Council of Social Service
QFF	Queensland Farmers' Federation
RBA	Reserve Bank of Australia
REC	Renewable Energy Certificate
RET	Renewable Energy Target

ROC	Retail operating costs
RPP	Renewable Power Percentage
SAC	Standard Asset Customer
Second consultation paper	Consultation paper seeking views on transitional issues relevant to the review of regulated retail electricity prices (notified prices) to apply from 1 July 2013 to 30 June 2014
SEQ	South East Queensland
Small customer	A customer that consumes 100 MWh of electricity per year or less
SRES	Small-scale Renewable Energy Scheme
STC	Small-scale Technology Certificate
STP	Small-scale Technology Percentage
Third consultation paper	Consultation paper seeking views on cost components and other issues relevant to the review of regulated retail electricity prices (notified prices) to apply from 1 July 2013 to 30 June 2014
TOU	Time-of-use
TUOS	Transmission Use of System
UTP	The Queensland Government’s Uniform Tariff Policy
Very large customer	A customer that consumes over 4 GWh per year

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EXECUTIVE SUMMARY

Since the introduction of full retail competition (FRC) on 1 July 2007, electricity consumers in Queensland have been able to enter into a market contract with the retailer of their choice. However, a significant proportion (particularly in the Ergon Energy distribution area) remain on non-market contracts paying regulated retail electricity prices, known as notified prices, which are determined by the Queensland Competition Authority (the Authority).

Most residential and small non-residential[1] electricity consumers in Queensland can choose to be supplied by their retailer at the notified price. Large non-residential customers in the Ergon Energy distribution area can only access notified prices if they have not previously entered into a market contract[2], while large non-residential customers in the Energex distribution area no longer have access to notified prices.

The Authority has been delegated the task of determining notified prices for all regulated retail electricity tariffs from 1 July 2013 to 30 June 2016. However, during that period, the Authority must set the notified prices on an annual basis, with the first pricing determination to apply from 1 July 2013 to 30 June 2014 (the 2013-14 Determination).

In making this 2013-14 Determination, the Authority has adopted an N+R cost build-up approach where the N (network cost) component is treated as a pass through and the R (energy and retail cost) component is determined by the Authority. An additional ‘headroom’ allowance has also been included to support competition in the retail market.

This is a continuation of the approach developed in setting notified prices for 2012-13, when a new set of cost-reflective retail tariffs was established. However, due to transitional arrangements introduced in 2012-13, many customers continue to access notified prices which are not cost-reflective. These arrangements were introduced to reduce the potentially significant price increases for some customers and in recognition of some physical constraints on customers changing tariffs related to metering and systems changes. The Authority has established further transitional measures for 2013-14 and beyond for certain customers.

Underlying Cost Drivers

Cost-reflective notified prices will increase in 2013-14 due to increases in the underlying costs of supply, which are predominately driven by increases in network charges. On average, network charges will increase by around 19% for Energex and 17% for Ergon Energy. These increases reflect:

(a) Large increases in the distributors’ revenue allowed by the Australian Energy Regulator (AER);

(b) The significant costs that the distributors have incurred in complying with the Queensland Government’s Solar Bonus Scheme. For example, Energex estimates that 9.2% of its 2013-14 network tariffs relate to the costs of complying with the Solar Bonus Scheme. These costs are expected to increase significantly in future years and their impact on network tariffs will peak in 2015-16, at which time approximately 29.5% of Energex’s network tariffs will be due to Solar Bonus Scheme costs;

(c) The catch-up from the Queensland Government’s Tariff 11 freeze in 2012-13, which was partly funded by a $40 million subsidy to Energex;

(d) Additional revenue to make up for under-recovered revenue in earlier years due to lower than forecast consumption; and

[1] Small customers are those consuming up to 100 MWh per annum.
[2] This restriction also applies to any future occupants of that premises (for example, if the premises is sold or occupied by a new tenant).

(e) The impact of declining consumption (some part of which is included in the Solar Bonus Scheme costs above) which means that network charges must increase to recover the allowed revenue.

Energy costs are the next biggest cost driver and are estimated to increase by around 9%. This increase is due to uncertainty in the wholesale energy market, which has increased the risks faced by retailers in purchasing energy, and a tightening of supply in the wholesale energy market.

Retail operating costs have also increased (by 24%) for small customers. This significant change comes as a result of the benchmarking approach being updated to take account of the most recent interstate estimate of retail operating costs by the Independent Pricing and Regulatory Tribunal (IPART). While the percentage increase is significant, retail cost is the smallest price component and the impact on costs is less than for networks or energy costs.

In addition to these cost increases, the retail margin, which is determined as a percentage of total costs, has increased from 5.4% to 5.7%, reflecting an updated assessment of the return that retailers should receive for committing capital to their businesses and for accepting risks associated with providing retail electricity services.

The impact of cost increases on individual customers will vary depending on the retail tariff(s) they are supplied under and their consumption characteristics.

While retail tariffs and prices have been determined on the basis of the network and retail costs expected to be incurred by retailers, the Authority is concerned that these do not necessarily provide an accurate signal to customers about the true underlying costs of their electricity consumption. While Energex and Ergon Energy have often cited peak demand as a key driver of their costs, many stakeholders have rightly questioned why both distributors provide such weak incentives to customers to shift their consumption to off-peak periods. For example, Ergon Energy does not have any time-of-use tariffs.

Similarly, differences in generation costs across the day are not passed through to customers as a result of the way in which retailers are billed for electricity they purchase from the National Electricity Market (NEM). Amending these arrangements (which are embodied in the Australian Energy Market Operator’s (AEMO’s) Metrology Procedures) could allow customers who already have electronic meters (not accumulation meters) to be settled against their individual consumption and priced according to their time-of-use.

Impacts on Residential Customers

The main retail tariff for residential customers is Tariff 11. A voluntary time-of-use tariff (Tariff 12) was introduced on 1 July 2012, which customers may access instead of Tariff 11 (if they have the appropriate metering installed), although very few customers have done so to date. In addition, a new time-of-use “peak smart” retail tariff (Tariff 13) will be introduced in 2013-14 which has been designed for customers with “Demand Response Ready” appliances.

In addition to accessing Tariff 11, Tariff 12 or Tariff 13, residential customers may also access the ‘off-peak’ or ‘controlled load’ tariffs (Tariffs 31 and 33).

Tariff 11

For 2012-13, the Government froze the Tariff 11 notified prices at their 2011-12 levels (with an addition to the variable charge to account for the impact of the carbon tax). This led to the fixed charge being lower, and the variable charge being higher, than the cost-reflective levels that would otherwise have prevailed. To support this decision, the Government provided a subsidy to Energex which ensured that retailers would not be penalised. The freeze was only for the one year (2012-13).

For 2013-14, the Authority has established a three-year transitional path to rebalance the fixed and variable components of Tariff 11 so that each component is cost-reflective by 1 July 2015.

As set out in Table 1 below, the transitional charges for 2013-14 are significantly higher than the frozen charges for 2012-13 and will increase a typical customer's annual bill from $1,184 to $1,451. This increase is made up of $73 to peg back the effects of the 2012-13 freeze of Tariff 11, a further $212 which reflects the increase in underlying costs between 2012-13 and 2013-14, and a $17 offset due to the effect of the three-year transition to cost-reflective charges for Tariff 11.

These customer bill impacts are larger than those projected in the Draft Determination as the underlying energy purchase costs and retail costs have proven to be marginally higher than anticipated at that time. In addition, following the Draft Determination, Energex revised downwards its forecast of average consumption by residential customers. As a result of these factors, both the fixed and variable components of Tariff 11 are marginally higher than envisaged at the time of the Draft Determination, which translates into higher expected customer bill impacts.

The impact on individual customers will vary depending on their consumption level. Smaller customers will face a larger percentage increase than larger customers. However, larger customers will face larger dollar increases and will continue to pay more than their actual costs of supply in order to subsidise smaller customers. This cross-subsidy will continue until the fixed and variable charges are fully rebalanced to cost-reflective levels.

Table 1: Tariff 11 – Bill Impacts for the Typical (Median) Customer

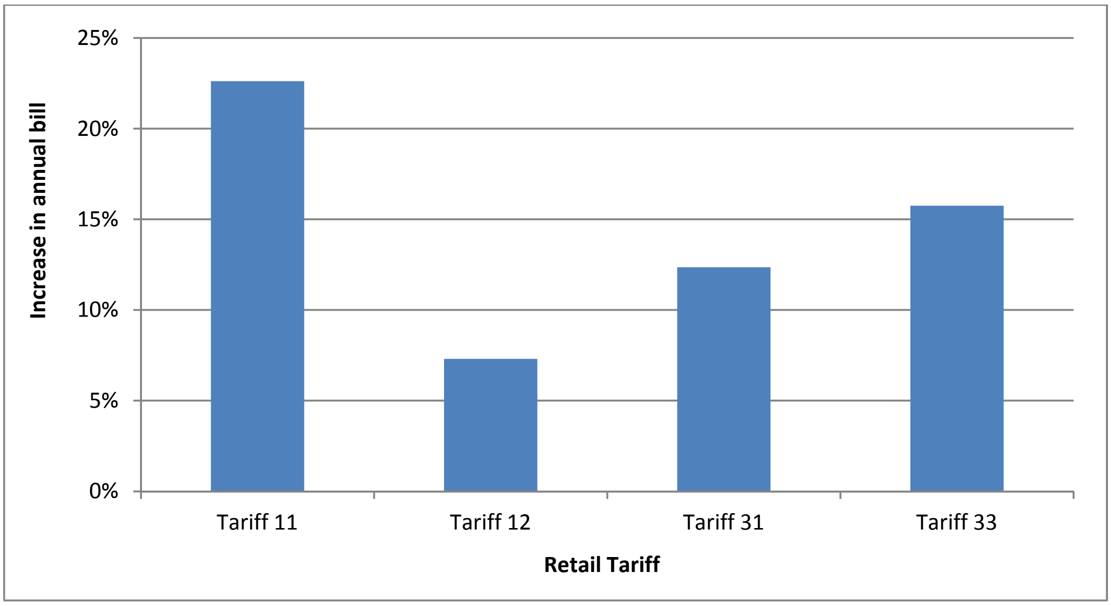
Tariff Component	*Frozen 2012-13*	*Transitional 2013-14*	*Increase*
Fixed charge (cents/day)[1]	26.170	50.219	*91.9%*
Variable charge (cents/kWh)[1]	23.071	26.730	*15.9%*
Annual Bill[2] ($, GST inclusive)	***1,184***	***1,451***	***22.6%***

1. GST exclusive.
2. Based on a typical (median) customer on Tariff 11 consuming 4,250kWh per annum.

Summary of Impacts on Residential Customers

Figure 1 shows the percentage changes that typical residential customers can expect in their annual electricity bills from 2012-13 to 2013-14 for each of the residential tariffs (except Tariff 13 which will be a new tariff in 2013-14). For Tariff 11, bill impacts will vary depending on each individual customer's level of consumption. For Tariff 12, bill impacts will vary depending on both the level of each individual customer's consumption and the time of day they consume. The bill impacts for Tariff 12 are lower than for other tariffs mainly because the underlying network charge for peak consumption under Tariff 12 has decreased relative to 2012-13.

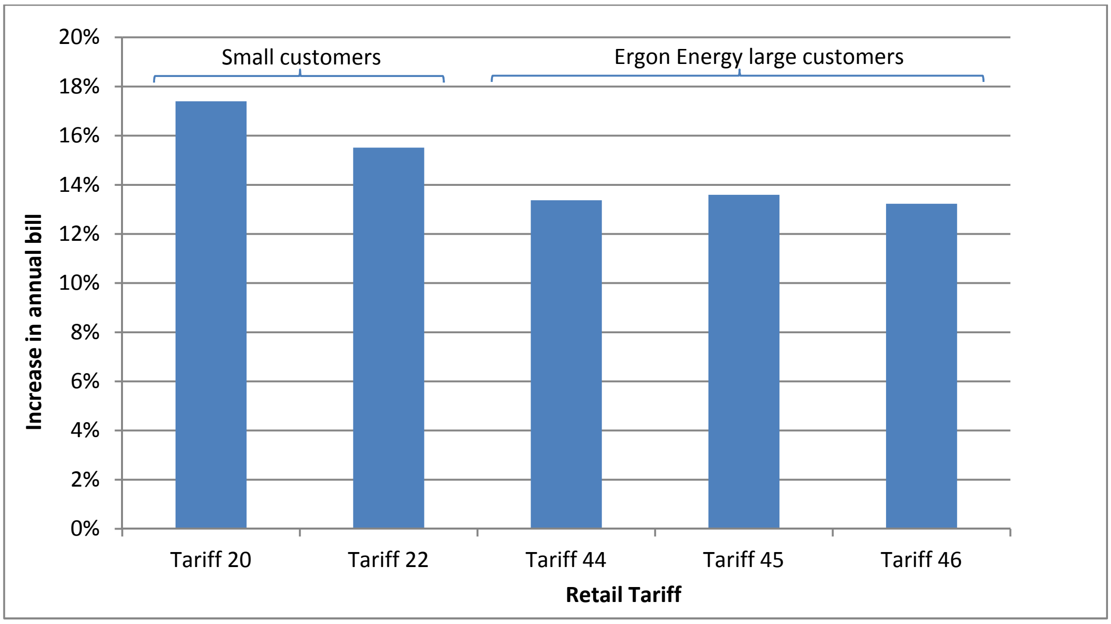
Figure 1: Change in Electricity Bills in 2013-14 for Typical (Median) Residential Customers



Impacts on Non-Residential Customers

Figure 2 presents the increases in annual bills for typical business customers on the cost-reflective tariffs. Bill impacts will vary depending on each individual customer's level and pattern of consumption.

Figure 2: Change in Electricity Bills in 2013-14 for Typical Business Customers



Note: Tariffs 41, 47 and 48 are not included due to a lack of useable data at this time.

Transitional Arrangements for Customers on Obsolete Tariffs

The Authority has established further transitional arrangements for customers on most of the existing obsolete tariffs as many customers would still face significant price impacts if they were immediately moved to a cost-reflective tariff.

All existing obsolete tariffs have been retained (with the exception of Tariffs 53 (large), 63 and 64 which will be removed). The prices associated with the retained tariffs will be increased by between 14.3% and 24% (depending on the tariff). These increases are based on the increase in the underlying cost of the cost-reflective tariff customers will eventually move to, plus a further increase to ensure the gap between the obsolete and cost-reflective tariff does not continue to grow. As a result of updated network and retail costs, the required escalation of most obsolete tariffs for 2013-14 has increased since the Draft Determination. However, the escalation of Tariff37 is lower because the majority of customers on this tariff are not as far from their cost-reflective tariff as previously estimated.

The Authority has set transitional periods of seven years for Tariffs 21, 37, 62, 65, 66, 20 (large) and 22 (small and large) and two years for Tariffs 41 (large) and 43 (large). The seven-year transitional period for most obsolete tariffs was chosen to allow customers on those tariffs time to achieve some return on investments made in equipment installed to optimise use of the obsolete tariffs and for them to adjust their consumption to better suit the new cost-reflective tariffs. The length of the transitional period will be reviewed next year to ensure the arrangements are still appropriate. The two-year period for Tariffs 41 (large) and 43 (large) recognises that most of these customers would already be better off on a cost-reflective tariff and provides sufficient time for those facing negative impacts to adjust. This is one year longer than proposed in the Draft Determination to align with the implementation of Ergon Energy's new network tariff strategy and to avoid the disruption to customers of having to move to an interim retail tariff.

New customers will be allowed to access the retained obsolete tariffs (to be referred to as transitional tariffs from 1 July 2013), except for Tariff 37, which has been obsolete for a number of years, and Tariffs 41 (large) and 43 (large), which will be removed at the end of 2014-15. New customers accessing the retained transitional tariffs will be subject to the same transitional period as existing customers. This will ensure that new and existing non-residential customers are treated equitably in the transition to cost-reflectivity.

Table 2 summarises the Authority's Final Determination on transitional arrangements for obsolete tariffs.

Table 2: Transitional Arrangements for Obsolete Tariffs 2013-14

Obsolete/Transitional Tariff	*Retain or Remove in 2013-14*	*Period to be Retained*	*2013-14 Increase*
Tariff 21 – transitional	Retain	7 years	24.0%
Tariff 37 – obsolete	Retain	7 years	20.0.%
Tariff 62 – transitional	Retain	7 years	20.0%
Tariff 63	Remove	N/A	N/A
Tariff 64	Remove	N/A	N/A
Tariff 65 – transitional	Retain	7 years	20.0%
Tariff 66 – transitional	Retain	7 years	20.0%
Tariff 20 (large) – transitional	Retain	7 years	14.3%
Tariff 22 (small and large) – transitional	Retain	7 years	16.3%
Tariff 41 (large) – obsolete	Retain	2 years	14.3%
Tariff 43 (large) – obsolete	Retain	2 years	14.3%
Tariff 53 (large)	Remove	N/A	N/A

1. INTRODUCTION

Since the introduction of full retail competition (FRC) on 1 July 2007, electricity consumers in Queensland have been able to choose their electricity retailer. However, most consumers are still able to choose to be supplied by their retailer at the regulated or notified price[3] determined by the Authority.

To date, the Authority has determined notified prices under delegation from the relevant Minister (the Minister for Energy and Water Supply). While the Authority has been delegated this function since the start of FRC, amendments to the *Electricity Act 1994* (Electricity Act) and *Electricity Regulation 2006* (Electricity Regulation) in late 2011 changed the method the Authority is required to follow in determining notified prices.

Previously, the Authority was required to adjust the existing notified prices annually according to its calculation of the change in the Benchmark Retail Cost Index (BRCI). Following the legislative changes mentioned above, commencing with the 2012-13 Determination, the Authority was required to set notified prices based on a new N+R cost build-up approach where the N (network cost) component was treated as a pass-through and the R (energy and retail cost) component was determined by the Authority.

This was a very different task to that undertaken previously and resulted in the introduction of a new set of retail tariffs aligned with the prevailing network tariff structure and retail prices which better reflected the cost of each customer's consumption. Given the significant change in methodology and some practical constraints on moving some customers immediately to new tariffs, the Authority implemented a number of transitional measures for certain customer groups for 2012-13. As a result, some customers continue to access tariffs that are below cost-reflective levels.

In addition, following the change of Government in the first half of 2012, the new Government decided to freeze (at the 2011-12 level) notified prices for the standard residential tariff (Tariff 11) for the following year, subject to the inclusion of costs associated with the introduction of the carbon tax. To implement this decision, 2012-13 notified prices for Tariff 11 were determined by the Minister, rather than the Authority.

On 5 September 2012, the Minister provided the Authority with a retail electricity pricing Delegation, requiring it to determine notified prices (including for Tariff 11) for a three-year period from 1 July 2013 to 30 June 2016. While the Delegation is for a three-year period, the Authority is still required to set notified prices on an annual basis, with the first pricing determination to apply from 1 July 2013 to 30 June 2014.

On 12 February 2013, the Authority received a revised Delegation which changed the release date of its Draft Determination from 15 February 2013 to 22 February 2013. All other content remained the same as for the 5 September 2012 Delegation.

1.1 Matters to Consider

In accordance with section 90(5)(a) of the Electricity Act, the Delegation requires that the Authority have regard to the following matters in making its price determination:

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

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

[3] Large non-residential customers in Energex's distribution area no longer have access to notified prices.

(c) the matters set out in the Terms of Reference.

In accordance with section 90(5)(b) of the Electricity Act, the Authority may also have regard to any other matter it considers relevant.

The Delegation includes a Terms of Reference which requires that the Authority consider a number of specific matters, including:

(a) basing each annual price determination on an N+R cost build-up approach;

(b) the Queensland Government's Uniform Tariff Policy (UTP);

(c) basing the network cost component for:

 (i) small customers on the network charges to be levied by Energex; and

 (ii) large customers on the network charges to be levied by Ergon Energy.

(d) transitional arrangements for the standard residential tariff (Tariff 11), the existing obsolete tariffs and customers on the large customer business tariffs introduced in 2012-13.

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

1.2 Approach to this Review

The two key factors the Authority is required to consider when making its price determination are cost-reflectivity and the impact on competition. The Authority must also consider whether and how to implement a transitional path to cost-reflective notified prices for certain customer groups (as noted above).

Unlike in some sectors (for example, electricity distribution and transmission) where barriers to entry such as high fixed costs and significant economies of scale tend to preclude the development of competition, there are no significant barriers to the development of competition in the retail electricity sector. Competition has developed considerably in the Queensland retail electricity market since it was introduced more than five years ago, although it is largely limited to South East Queensland (SEQ) as a result of the UTP. Around 70% of customers in SEQ are supplied under market contracts.

In light of these factors, the Authority considers that part of its role in setting notified prices is to provide a transition to effective competition and eventual price deregulation, particularly in SEQ. While the Government has stated that it is not convinced that small customers are adequately protected from the effects of moving to a fully deregulated market at this time, under the Australian Energy Market Agreement it has agreed to phase out retail price regulation if effective competition can be demonstrated[4].

[4] So far, Victoria and South Australia are the only states that have deregulated retail electricity prices.

As a result, notified prices will continue to provide a level of protection for customers against the exercise of any excessive market power, until the Government is satisfied that competition provides a sufficient constraint on prices such that price regulation is no longer required[5].

At the same time, the Authority considers that notified prices should not act as a constraint on the development of effective competition. This is consistent with the Authority's decision to include an explicit allowance for headroom in this Determination and the 2012-13 Determination. Including headroom is also consistent with the Government's policy objective that consumers, wherever possible, should have the opportunity to benefit from competition and efficiency in the marketplace.

What About Customers Outside SEQ?

In accordance with the Government's UTP, the Authority must ensure that, wherever possible, non-market customers of the same class have access to uniform retail tariffs and pay the same notified price for their electricity supply, regardless of their geographic location.

The UTP works by subsidising customers in Ergon Energy's distribution area where network costs are considerably higher than in the more densely populated SEQ. Under the UTP, the Government subsidises the notified prices payable by regional customers supplied by Ergon Energy Queensland (EEQ) via a Community Service Obligation (CSO) payment.

While the UTP means that customers will have access to the same notified prices wherever they live, most customers in Ergon Energy's network area outside of SEQ, particularly small customers, do not have access to lower-priced competitive market offers because other retailers do not have access to the CSO subsidy. As a result, only around 1% of customers outside SEQ are supplied under a market contract. There was widespread support from retailers and consumers for providing the CSO to the distribution entity – Ergon Energy Corporation Limited (EECL) – in order to promote competition. While this would promote competition, it is a matter for the Government to consider, not the Authority.

The UTP does create some difficulty when determining notified prices depending on how literally it is to be interpreted. If the Authority determines notified prices in order to encourage competition in SEQ and more and more SEQ customers take up lower-priced market offers available to them, there will be fewer and fewer SEQ customers actually paying notified prices for their electricity.

This creates a disparity between the lower market prices paid by the majority of customers in SEQ and the higher notified prices customers elsewhere must pay, which may be inconsistent with the intent of the UTP. The application of the UTP may need to be reviewed as progress is made towards deregulation in SEQ. In effect, this issue has already been addressed for large customers because, since 1 July 2012, large non-residential customers in Energex's area no longer have access to notified prices and the Authority has set notified prices for large customers based on Ergon Energy's network charges.

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[5] The Australian Energy Market Commission (AEMC) is required to assess the competitiveness of electricity markets in each jurisdiction for the purposes of recommending whether price regulation should be phased out and is undertaking a review of the NSW market. A review of the Queensland market is scheduled to follow, although it is unclear whether it will proceed given that the Standing Council on Energy and Resources (SCER) is developing a new review approach (expected to be in place by the end of 2013) which will provide a more market-wide and ongoing review of the state of competition. See AEMC, *Issues Paper - Review of Competition in the Retail Electricity and Natural Gas Markets in New South Wales*, 13 December 2012, p 5; and Standing Council on Energy and Resources (SCER), *Meeting Communique*, 14 December 2012, pp 1-2.

1.3 The Review Process

On 21 September 2012, the Authority released an Interim Consultation Paper advising interested parties of the commencement of the review. The Authority received 23 submissions in response to the Interim Consultation Paper.

On 2 November 2012, the Authority released a second consultation paper which discussed the transitional issues the Authority is required to consider as part of this review. To allow for more open discussion of the issues raised in that paper, the Authority also held eight workshops in regional centres between 19 November and 29 November. These workshops were held in Gatton, Emerald, Bundaberg, Cairns, Mareeba, Townsville, Ayr and Mackay. The Authority received 28 submissions in response to this consultation paper.

On 12 December 2012, the Authority released a third consultation paper which discussed issues relating to the three cost components (network, energy and retail), competition, headroom and other matters. This was followed by a workshop held in Brisbane on 19 December 2012 to discuss both the transitional issues and cost components consultation papers. The Authority received 24 submissions in response to the cost components consultation paper.

The Authority engaged ACIL Tasman (ACIL) to provide expert advice on estimating energy costs and released a preliminary report prepared by ACIL on its proposed approach (ACIL preliminary draft report) to coincide with the release of the third consultation paper.

On 22 February 2013, the Authority released its Draft Determination and ACIL's draft report on energy costs (ACIL draft report). This was followed by a further series of workshops in Cairns, Mareeba, Townsville, Ayr, Mackay, Gatton, Emerald, Brisbane and Bundaberg in late February and early March. The Authority received 49 submissions in response to the Draft Determination.

All papers released by the Authority, and non-confidential submissions received in response, are available from the Authority's website (www.qca.org.au). A list of all submissions received during the price review process is provided in **Appendix B**.

The Authority is now releasing this Final Determination, which includes regulated retail tariffs and prices for 2013-14 and explains how these were determined. In making its Final Determination, the Authority has taken into account the requirements of the Electricity Act and the Delegation, matters raised in submissions, ACIL's final report on the cost of energy (ACIL final report) and its own investigations.

2. NETWORK COSTS

Retail electricity prices comprise three main cost components. The first of these is the cost of transporting electricity from generators to consumers, which requires the use of both transmission and distribution networks. Transmission networks transport electricity at high voltages across the state (and interstate) while distribution networks distribute electricity at lower voltages from transmission connection points to households, small businesses and industrial users. Typically, network costs account for around 50% of the final cost of electricity for small customers.

The main transmission network service provider in Queensland is Powerlink. The two main distribution networks in Queensland are owned and operated by Energex and Ergon Energy. Energex's network services SEQ, while Ergon Energy's network extends across the remainder of the State. As regulated monopoly businesses, the revenues to be raised via charges by Powerlink, Energex and Ergon Energy are determined by the AER.

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

The Delegation 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. The Delegation also requires the Authority to consider basing notified prices for small customers (those consuming up to 100 MWh per year) on Energex network tariffs and notified prices for large customers (those consuming more than 100 MWh per year) on Ergon Energy network tariffs (as only large customers in the Ergon Energy distribution area are able to access notified prices).

2.1 Network Tariffs for Small Customers and Unmetered Supplies

2.1.1 Residential Tariffs

There was broad support in submissions for continuing to use Energex network tariffs as the basis for notified prices for residential customers. However, there was considerable discussion amongst stakeholders regarding the time-of-use aspects of Energex's residential network tariffs.

Some respondents, including Energex, EnergyAustralia, Queensland Government and the Queensland Council of Social Service (QCOSS) supported the inclusion of more time-of-use options in tariffs for residential customers to help manage peak demand. However, a common theme among stakeholders was that the time-of-use tariffs proposed by Energex offered insufficient incentives for customers to switch to a time-of-use tariff and change consumption patterns.

The network tariffs for residential customers that Energex has proposed for 2013-14, and the regulated retail tariffs they align to, are presented in Table 2.1.

Table 2.1 Network Tariffs for Residential Customers

Retail tariff	*Energex network tariff*
Tariff 11 - Residential[1]	8400
Tariff 12 - Residential (time-of-use)	8900
New - Tariff 13 – Residential (time-of-use PeakSmart)	***7600***
Tariff 31 - Night rate (super economy) [1]	9000
Tariff 33 - Controlled supply (economy) [1]	9100

[1] *These tariffs also apply to residential customers using card-operated meters.*

Residential Time-of Use Tariffs (Tariffs 12 and 13)

As the Authority noted in its consultation papers, only a very small number of customers have so far opted for supply under Tariff 12. The Authority suggested that it was difficult to say whether the apparent lack of interest in Tariff 12 relative to Tariff 11 was due to the Government's decision to freeze Tariff 11 or whether it was because the underlying network charges make Tariff 12 unattractive relative to Tariff 11 for all but a very small group of customers.

Energex and the Government suggested that the high fixed charge for Tariff 12 relative to that for (the frozen) Tariff 11 had diminished the appeal of Tariff 12. However, other respondents, including Origin Energy, EnergyAustralia and Mr Brimblecombe, suggested that the tariff freeze was only partly to blame and that the relativities between the underlying network charges (network tariff 8400 for Tariff 11 and network tariff 8900 for Tariff 12) were also part of the problem. For example, EnergyAustralia provided an analysis that showed that a customer consuming 6 MWh of electricity per year in a typical split across peak, shoulder and off-peak periods would pay significantly more on network tariff 8900 (Tariff 12) than on network tariff 8400 (Tariff 11). Based on its analysis, EnergyAustralia suggested that a customer would have to shift a significant proportion of their energy use to the off-peak period in order to incur lower network charges on Tariff 12 relative to Tariff 11.

EnergyAustralia encouraged the Authority, Energex and the AER to ensure that charges for network tariffs 8400 and 8900 were set such that Tariff 12 was a competitive alternative for Tariff 11. The Government encouraged the Authority to work with Energex so that the network tariff (8900) for Tariff 12 can be developed with the transition path for Tariff 11 in mind. Ergon Energy, Origin Energy, QCOSS and the Queensland Farmers' Federation (QFF) acknowledged that network pricing was a matter for Energex and the AER.

In response to the Draft Determination, Energex commissioned Ernst and Young to review its time-of-use pricing structure for network tariff 8900. The review compared Energex's 8900 tariff to other time-of-use network tariffs across Australia and concluded that, while there are differences across jurisdictions with respect to the length and time of peak, shoulder and off-peak periods, and the strength of the peak price signal, Energex's time-of-use tariff structure is not fundamentally different to that of other distributors. Ernst and Young also found that the ratio of Energex's peak to off-peak price is comparatively low, but is within the range applied by other distributors. Ernst and Young concluded that the price freeze applied to Tariff 11 was the main reason for the diminished attractiveness of Tariff 12 relative to Tariff 11 during 2012-13, in conjunction with the modest ratio of the peak to off-peak components of Tariff 12 during 2012-13.

Energex has also proposed to introduce a new time-of-use "PeakSmart" network tariff (7600) for residential customers, commencing in 2013-14. This tariff is designed for customers with “Demand Response Ready” appliances, which allow Energex to control these appliances for the purposes of managing peak network demand. In return, customers on this new tariff would receive an off-peak network charge that is 2.0 c/kWh lower than that for Tariff 12. The new tariff is otherwise similar to the time-of-use network tariff (8900) that is the basis for the existing residential time-of-use tariff, Tariff 12. For the purposes of the Draft Determination, the Authority designated the corresponding retail tariff as Tariff 13.

EnergyAustralia considered that it was unlikely Tariff 13 would prove popular with customers as it is only marginally more attractive than Tariff 12, which has not been adopted by many customers to date.

The Government acknowledged the issues potentially affecting customer uptake of Tariff 12, but supported the introduction of the new PeakSmart Tariff 13. The Government also indicated that it intends to monitor customer uptake of Tariff 13 during 2013-14 and consult with the distributors to assess whether it provides adequate incentives to customers.

EnergyAustralia expressed concern that retailers must implement a new retail tariff each time Energex creates a new network tariff and argued that this generates a significant amount of additional work and costs for retailers. EnergyAustralia questioned whether there is a need to create a new retail tariff for each network tariff, or if an existing tariff (in this case Tariff 12) could be used to achieve a similar outcome for customers with PeakSmart appliances. EnergyAustralia suggested that Energex should leave network tariff 7600 closed to customers during 2013-14 until it can be seen whether Tariff 12 will become more popular with customers.

Solar Bonus Scheme Customers

In its Final Report on 'Estimating a Fair and Reasonable Solar Feed-in Tariff for Queensland', the Authority considered options to reduce the significant burden being placed on non-Photovoltaic (non-PV) customers by the PV scheme. The Authority suggested that the total burden of the PV scheme could be partially reduced if PV customers were required to pay PV customer-specific network charges that reflect the true costs of their connection to the network. One stakeholder, Mr Atherton, agreed with the Authority’s suggestion, noting that people with solar panels do not contribute toward the capital costs of the network and suggested they be required to pay a substantial connection fee based on the capacity of their solar panels.

However, the Authority did note that network businesses are subject to clause 6.18.4(b)(4) of the National Electricity Rules (NER) which, in simple terms, requires that retail customers with micro-generation facilities should be treated no less favourably than retail customers without such facilities but with a similar load profile.

While this requirement may constrain the network businesses’ attempts to implement more efficient network access prices for PV customers, the Authority encouraged the distributors to seriously consider tariffs for PV customers in the context of broader network tariff reform programs, as Queensland moves to more cost-reflective retail pricing during the next three years.

While supporting cost-reflectivity in network tariffs, EnergyAustralia was not convinced that a new PV network tariff would necessarily be the best solution, even though it could theoretically reduce the existing cross-subsidisation of PV customers by non-PV customers. EnergyAustralia suggested that the extra costs imposed by PV customers compared to non-PV customers vary widely and could be difficult to predict and recover equitably. EnergyAustralia also suggested that applying such a tariff only to new PV customers would be unfair, would be costly for retailers and would likely create a significant customer backlash.

In response to the Draft Determination, Energex considered that clause 6.18.4(b)(4) of the NER would preclude it from creating a new network tariff specifically for PV customers and accordingly it has not done so in its proposed network tariffs for 2013-14.

In its submission, the Government acknowledged the significant impact of the Solar Bonus Scheme on network prices. It stated that managing this ongoing impact is a key priority for the Government and that it is considering what further changes could be made to the Solar Bonus Scheme to provide a more equitable solution for Queensland customers.

The charges Energex has proposed for each residential network tariff are provided in Table 2.2.

Table 2.2: Energex Network Charges for 2013-14 for Residential Regulated Retail Tariffs (GST Exclusive)

Retail tariff	*Energex network tariff*	*Fixed charge[a]*	*Variable rate (flat)*	*Variable rate 1 (off-peak)*	*Variable rate 2 (shoulder)*	*Variable rate 3 (peak)*
		c/day	*c/kWh*	*c/kWh*	*c/kWh*	*c/kWh*
Tariff 11 - Residential (flat rate)	8400	43.900	11.957			
Tariff 12 - Residential (time-of-use)	8900	57.900		8.779	11.457	19.141
Tariff 13 - Residential (PeakSmart)	7600	57.900		6.779	11.457	19.141
Tariff 31 - Night rate (super economy)	9000		4.838			
Tariff 33 - Controlled supply (economy)	9100		8.779			

a Charged per metering point.

Some stakeholders, including Mr McCarthy, Pioneer Valley Water (PVW), Canegrowers and the Association of Independent Retirees argued that Solar Bonus Scheme costs should not be funded through regulated network tariffs, with some respondents suggesting those costs be funded directly by the Government. This was one of a number of options recommended in the Authority's Final Report of March 2013, which are being considered by the Minister for Energy and Water Supply.

The Authority's Position

The Authority notes the concerns raised in submissions about the attractiveness of Energex's time-of-use residential network tariff relative to its flat residential network tariff. While this may be due partly to the Government's decision to freeze retail Tariff 11 (with compensation to retailers provided via a one-off reduction in the fixed component of the underlying network charge), the impact of that decision on network charges will cease at the end of this current pricing year. However, a true comparison of the relative attractiveness of Tariffs 11 and 12 will only be possible once the fixed and variable components of Tariff 11 are rebalanced to their cost-reflective levels, which will not be completed until 1 July 2015 (as discussed in Chapter 6). Once completed, this is likely to reveal the more fundamental problem, as referred to by EnergyAustralia, that the underlying network charges make Tariff 12 unattractive relative to Tariff 11 for most customers.

Energex's new PeakSmart network tariff will provide another time-of-use option for residential customers, although it remains to be seen whether the additional 2.0 c/kWh discount to the off-peak rate will be sufficient to encourage many customers to relinquish some control of certain appliances (typically air conditioners only) to Energex[6].

The Authority notes EnergyAustralia's concerns about the costs of implementing new retail tariffs. However it considers that, wherever possible, a notified retail tariff should be created to accompany every network tariff. This would avoid the situation where a non-market customer may be eligible for a new network tariff, but denied access if there is no corresponding notified retail price.

While the uptake of Tariff 12 has been limited to date, Energex's proposed 2013-14 tariff structures for network tariffs 8900 and 7600 (Tariffs 12 and 13) appear to represent a more attractive option than was the case during 2012-13. Energex considers there are a significant number of customers who would be better off on Tariff 12 during 2013-14 than was the case in 2012-13 and, given that Tariff 13 and Tariff 12 are so similar, this potential for greater customer benefits from Tariff 12 might also translate to uptake of Tariff 13 during 2013-14.

Regardless, it would be inappropriate for the Authority to not create an accompanying notified retail price for new network tariffs simply because the number of customers expected to opt-in to them might be low. This is an important consideration in relation to time-of-use tariffs in particular given that the Authority has no scope of its own to introduce time-of-use signals through the R component and must rely on price signals conveyed through network tariffs, as discussed in Chapter 3.

With regard to the strength of the incentives in existing time-of-use tariff structures generally, the Authority agrees with Energex that price signalling through the N component alone will not achieve the best outcomes for customers or networks. The existing obstacles to time-of-use price signalling through the wholesale energy component should be addressed, and the Authority encourages the Government to pursue required changes to metrology procedures to accommodate more cost-reflective time-of-use pricing of energy, in addition to the network components.

While, as noted above, Energex has not included a separate PV customer network tariff, a less contentious pricing option for PV customers might be to require them to shift to the time-of-use Tariff 12. As part of the upgrade required to connect these customers to the network, all PV customers would already have meters capable of use with Tariff 12. Under this approach, PV customers would still have an incentive to export, rather than consume, the PV power they produce but it would at least discourage PV customers from consuming electricity at peak times on activities they put off during the day in order to maximise their PV exports. This move would not result in PV customers paying the actual network costs they cause to be incurred but it would at least move them some small step in that direction. Given these customers are sufficiently aware of their electricity costs to invest in PV installations, they are likely to also be sufficiently motivated to consider the benefits of shifting their consumption (where possible) to off-peak periods under Tariff 12.

While the Authority has some concerns regarding Energex's approach to pricing, it nevertheless considers that Energex's network tariffs provide the best available basis for setting flat, time-of-use and controlled load regulated tariffs for residential customers. This view was broadly supported in submissions and is consistent with the requirement in the Delegation for the Authority to consider Energex's network tariffs and prices in setting

[6] In response to the Draft Determination, Energex pointed out that Tariff 13 will be an 'anytime' supply tariff similar to Tariff 11 or Tariff 12. While there will be a number of specific controllable appliances within the premises, electricity supply will be provided to the premises at all times. Energex advised that a large number of appliances, including televisions and computers, would not be affected.

notified prices for small customers. Any further refinement of, or addition to, these tariffs is a matter for Energex and the AER to determine within the requirements of the NER. As the Authority has no role in that process, it is unable to influence the setting of network tariffs or prices, as was suggested in some submissions.

2.2 Tariffs for Small Business and Unmetered Supplies

2.2.1 Small Business

In response to the Authority's Consultation Papers and Draft Determination, many submissions from small business customers raised concerns about having to move to a cost-reflective regulated retail tariff based on an Energex network tariff. For example, many individual farmers and farming groups, such as Canegrowers, Cotton Australia, PVW and the QFF, highlighted that farmers had made investment decisions based on the peak and off-peak rates in the retail tariff they had previously been on and that moving to a new retail tariff with a different structure could require considerable further capital investment to adapt business processes.

The key concern coming from these submissions, and evident at many of the workshops run by the Authority, was that the increase in the off-peak rate and the decrease in the peak rate under Tariff 22 (which is based on Energex network tariff 8800) in 2012-13 would significantly increase electricity costs for customers who had previously been relying on the lower off-peak rates available in Tariffs 22, 62, 63, 64 and 65. It was also noted that the reduction in the gap between peak and off-peak charges would reduce the incentive for customers to use off-peak electricity. While the Government noted that Energex had increased the difference between the peak and off-peak rates underlying Tariff 22 for 2013-14, it expressed concern that this was largely due to an increase to the peak rate.

As the Authority noted in its Final Determination for 2012-13, given that there is no time-of-use signalling in the R component of tariffs, the strength of signalling in Tariff 22 depends entirely upon that included in Energex's underlying network tariff. For this reason, while noting the requirement to treat network costs as a pass-through and that the structure of network charges is a matter for Energex and the AER, the Authority encouraged Energex to review its network tariffs to ensure they are sending appropriate pricing signals to customers regarding the differential network costs associated with their time-of-use and are providing appropriate demand management signals to customers.

Energex noted the significant stakeholder concern regarding the absence of strong time-of-use signals in Tariff 22 and the significant financial impact this would have on farmers and irrigators who have established their businesses based on time-of-use signals delivered through the now obsolete tariffs. In response to the Draft Determination, Energex further increased the difference between the peak and off-peak rates for network tariff 8800 by allocating more weight to the daily fixed component, increasing the peak consumption rate and slightly decreasing the off-peak rate. Energex's revised network tariff 8800 now features a 6.132 c/kWh difference between the peak and off-peak consumption rates compared to a 4.363 c/kWh difference proposed for the purposes of the Draft Determination. The off-peak consumption rate is now slightly lower than it was during 2012-13.

In addition, Energex's small customer demand network tariff (8300), which underpins retail Tariff 41, was significantly rebalanced since the Draft Determination. In its 2013-14 pricing proposal, Energex indicated that the preliminary tariff used for the purposes of the Draft Determination was similar to that applying during 2012-13, which was designed to preserve the price signals inherent in Powerlink's transmission charges. This resulted in a network tariff which was heavily weighted toward the fixed charge component, in a similar way to Energex's demand tariffs for large customers.

For 2013-14, Energex has rebalanced the components of network tariff 8300 in response to customer feedback regarding the 2012-13 tariff structure. The tariff is now more heavily weighted toward the variable consumption charge, rather than the daily fixed charge, as was the case during 2012-13. Energex indicated that this new structure will better accommodate the relative size differences between customers on demand tariffs, reducing the price impact for smaller customers and smoothing the step between non-demand and demand tariff classes[7].

The network tariffs Energex has proposed for small business customers and unmetered supplies for 2013-14, and the regulated retail tariffs they align to, are presented in Table 2.3.

In response to the concerns raised by stakeholders in relation to the diminished gap between peak and off-peak rates available under Tariff 22, Energex also suggested that its three part time-of-use network tariff (8900) for residential customers could form the basis of a new retail tariff for farming and irrigation customers which would provide an alternative to the two-part time-of-use Tariff 22.

2.2.2 Unmetered Supplies

No submissions raised any concerns in relation to the treatment of unmetered supplies. Ergon Energy supported continuing to use Energex's network tariff as the basis for notified prices for unmetered supplies.

Table 2.3: Network Tariffs for Small Business Customers and Unmetered Supplies

Retail tariff	*Energex network tariff*
Tariff 20 – Business (flat rate)	8500
Tariff 22 – Business (two part time-of-use)	8800
Tariff 41 – Low voltage (demand)	8300
Tariff 91 – Unmetered	9600

The charges Energex has proposed for each of these small customer network tariffs are provided in Table 2.4.

[7] For example, from network tariff 8500 or 8800, to network tariff 8300.

Table 2.4: Energex Network Charges for 2013-14 for Other Small Customer Regulated Retail Tariffs and Unmetered Supplies Other Than Street Lighting (GST Exclusive)

Retail tariff	*Energex network tariff*	*Fixed charge[a]*	*Demand charge*	*Variable rate (flat)[b]*	*Variable rate (off-peak)*	*Variable rate (peak)*
		c/day	*$/kW/month*	*c/kWh*	*c/kWh*	*c/kWh*
Tariff 12 - Residential (time-of-use)	8900	57.900		11.457	8.779	19.141
Tariff 20 - Business (flat rate)	8500	72.500		12.181		
Tariff 22 - Business (time-of-use)	8800	72.500			8.095	14.227
Tariff 41 - Low voltage (demand)	8300	677.200	20.887	1.439		
Tariff 91 - Unmetered	9600			9.448		

a Charged per metering point.
b Shoulder for Tariffs 12.

The Authority's Position

As noted above, there was a lot of negative comment expressed in submissions and workshops regarding the reduced incentive to consume off-peak as a result of moving to retail tariffs based on Energex's network tariffs. Energex has attempted to address some of these concerns by adjusting the peak/off-peak charges for network tariff 8800 (retail Tariff 22).

The difference between the peak and off-peak rates for the network tariff 8800 has increased, from 1.876 c/kWh in 2012-13 to 6.132 c/kWh in 2013-14, due to a significant increase in the peak rate, along with a modest reduction in the off-peak rate. As a result, customers concerned about the change in the structure of Tariff 22 in 2012-13 will have a stronger incentive to consume off-peak under these proposed network charges.

Energex had initially proposed to provide farmers and irrigators with access to its three-part time-of-use residential network tariff 8900. However, while the peak/off-peak differential in network tariff 8900 was greater than that for the two-part time-of-use network tariff 8800 underpinning Tariff 22(which would provide a stronger incentive for customers to consume off-peak) this was only because the peak rate in network tariff 8900 was significantly higher than that for network tariff 8800 as the off-peak rate for network tariff 8900 was also higher than that for network tariff 8800. In its Draft Determination the Authority questioned whether this would provide a real option for customers. In response to the Draft Determination, Canegrowers, PVW and Mareeba Dimbulah Area Council (MDIA Council) agreed that irrigators would not be better off on a retail tariff based on Energex's network tariff 8900.

Energex has not pursued this option following the comments in the Draft Determination and the lack of interest from potential customers. It also felt that the extended transitional arrangements proposed by the Authority provided a better alternative for customers.

Given the hurdles that need to be crossed in order to include some element of time-of-use signalling in the R component of tariffs, as discussed in Chapter 3, the strength of time-of-use signalling in notified retail prices for small customers will continue to depend entirely on that included in Energex's network tariffs. The Authority acknowledges that the changes proposed by Energex to its network prices for 2013-14 may not alleviate the concerns that many customers have about moving to cost-reflective notified prices based on Energex network tariffs. Whether further refinement of network tariffs is warranted, or possible, is up to Energex and the AER.

In the meantime, the requirements for notified prices to be cost-reflective and to be based on an N+R approach mean that the Authority must base notified prices on either Energex's or Ergon Energy's network tariffs. In setting prices for small customers, the Delegation suggests the Authority should consider Energex's network tariffs. While some customers may think Energex's network tariffs do not provide sufficient incentive to consume off-peak, the alternative network tariffs from Ergon Energy do not include any time-of-use elements. The concern raised by these customers is not due to the choice of Energex or Ergon Energy network tariffs as the base for establishing the retail tariffs, but rather the move from a very favourable but non cost-reflective retail tariff to a cost-reflective one.

Moreover, even if Ergon Energy were to introduce some time-of-use network tariffs in future, it is highly unlikely that the charges for those tariffs (based on Ergon Energy's costs) could be lower than for similar Energex tariffs, due to the higher costs of distributing electricity in regional Queensland compared to SEQ.

The Authority therefore considers that it should continue to use the Energex network tariffs as the basis for flat, time-of-use and demand-based regulated retail tariffs for small business customers and for unmetered supplies but understands that some customers will be adversely affected by the move to cost-reflective notified prices. The Authority has given this issue further consideration in developing transitional arrangements, as discussed in Chapter 6.

2.3 Network Tariffs for Large Customers and Street Lighting

2.3.1 Large Customers

There was mixed support in submissions for using Ergon Energy's network charges as the basis for notified prices for large customers.

For example, EnergyAustralia, the Queensland Government and Ergon Energy supported this approach on the basis that it (somewhat) improved the cost-reflectivity of notified prices for large customers. EnergyAustralia considered this was a positive step that might encourage other (non-EEQ) retailers to enter the market and begin making competitive offers to some large customers. This view was supported by AGL, which indicated that it had been active in providing competitive market offers to large customers in Ergon Energy's network area since the creation of cost-reflective tariffs for these customers. The Government also suggested that the approach was appropriate given that, from 1 July 2012, large business customers in Energex's network area no longer had access to notified prices.

In contrast, some stakeholders did not support this approach. For example, while acknowledging that basing notified prices for large customers on Ergon Energy's network tariffs would make notified prices more cost-reflective and that large customers in SEQ no longer have access to notified prices, the Chamber of Commerce and Industry Queensland (CCIQ) suggested that this approach would not achieve equity between businesses in regional areas and those in SEQ and suggested that this was inconsistent with the Government's UTP. MSF Sugar and Sucrogen supported this view.

CCIQ also noted that small businesses in Ergon Energy's network area would not pay cost-reflective prices while their large competitors will, which would result in cross-subsidisation between these groups. CCIQ therefore suggested that a better approach would be to base notified prices for large customers on Energex's network tariffs, or that there may be merit in using an average of the Energex and Ergon Energy network costs for each tariff based on the total number of users in each tariff category.

One stakeholder, Mr Brimblecombe, questioned how notified prices for customers consuming just below and above the (100 MWh/year) threshold between small and large customers could be so different and yet be cost-reflective.

Submissions from a number of large customers, including Australian Sugar Milling Council (ASMC), Bundaberg Walkers Engineering Limited (BWEL), Toowoomba Regional Council, SunWater and Sucrogen, raised similar concerns to those raised by small customers noted above, about having to move to regulated retail tariffs that provide less incentive to consume electricity during off-peak periods. In addition, some large customers on obsolete tariffs that do not include any demand or capacity charges suggested that moving to retail tariffs that have demand and capacity charges would result in much higher electricity costs for their businesses.

Many of these stakeholders suggested that Ergon Energy's network tariffs needed to be altered to better suit the needs of customers, for example, by providing incentives for off-peak consumption. Similarly, the ASMC suggested that Ergon Energy should make available an 'auxiliary load tariff' for use during periods when sugar mills are exporting electricity to the network so that high fixed charges could be avoided during these periods. While the Authority does not support this view – since fixed charges are meant to recover the cost of assets in place whether they are used or not – the issue is one for Ergon Energy and not something that the Authority can implement.

Some stakeholders, mainly farmers and irrigators or their representatives, suggested notified prices based on Ergon Energy's network tariffs were so high it would be more economic for them to disconnect from the network and meet their energy needs some other way, for example, by using diesel generators or solar PV installations.

The network tariffs Ergon Energy has proposed for large customers and street lighting for 2013-14, and the regulated retail tariffs they align to, are presented in Table 2.5. These network tariffs remain unchanged from 2012-13. Ergon Energy indicated that it is reviewing its network pricing, due to anticipated reductions in future network investment and revenue requirements. Ergon Energy recognised the role of time-of-use signals in managing peak demand and was examining possible time-of-use energy and demand charges as part of its review. However, while Ergon Energy suggested that its review will affect the structure of network tariffs and the level of charges, these changes would not begin to be implemented until 2014-15.

Ergon Energy highlighted a number of factors contributing to the uncertainty over future network pricing, including the new distribution determinations by the AER, which will apply from 2015-16, as well as reviews being undertaken by the Queensland Government's Inter-Departmental Committee and Independent Review Panel.

Table 2.5: Network Tariffs for Large Customers and Street Lighting in the Ergon Energy Distribution Area

Retail tariff	*Ergon Energy network tariff*
Tariff 44 - Over 100 MWh small (demand)	EDST1
Tariff 45 - Over 100 MWh medium (demand)	EDMT1
Tariff 46 - Over 100 MWh large (demand)	EDLT1
Tariff 47 - High voltage (demand)	EDHT1
Tariff 48 - Over 4 GWh High voltage (demand)	EDHT1
Tariff 71 - Street Lighting	EVUT1

The charges Ergon Energy has proposed for each of these large customer network tariffs are provided in Table 2.6.

Table 2.6: Ergon Energy Network Charges for 2013-14 Large Customer Regulated Retail Tariffs and Street Lighting (GST Exclusive)

Retail tariff	*Ergon Energy network tariff*	*Fixed charge[a]*	*Demand charge*	*Variable rate (flat)*
		c/day	*$/kW/month*	*c/kWh*
Tariff 44 - Over 100 MWh small (demand)	EDST1	582.600	31.682	1.913
Tariff 45 - Over 100 MWh medium (demand)	EDMT1	2,235.400	27.486	1.913
Tariff 46 - Over 100 MWh large (demand)	EDLT1	3,642.700	26.416	1.913
Tariff 47 - High voltage (demand)	EDHT1	2,306.200	21.109	1.853
Tariff 48 - Over 4 GWh High voltage (demand)	EDHT1	2,306.200	21.109	1.853
Tariff 71 - Street lighting[b]	EVUT1	0.600	-	23.435

a Charged per metering point.
b The fixed charge for street lighting applies to each lamp.

The Authority's Position

The Authority disagrees with the suggestion by CCIQ and others that basing notified prices for large customers on Ergon Energy's network tariffs, rather than Energex's, is inconsistent with the Government's UTP. The UTP requires that non-market customers of the same class should have access to the same notified prices, regardless of their geographic location. Following the Government's decision to remove access to notified prices for large customers in Energex's network area from 1 July 2012, the only large non-market customers in Queensland are in Ergon Energy's network area. As the Authority is required to calculate cost-reflective notified prices based on an N+R approach, it has no option other than to use Ergon Energy's network charges for setting notified prices for large customers. This also rules out using an average of Energex and Ergon Energy network prices, as suggested by CCIQ.

The same reasoning applies for street lighting because de-regulation of that market in SEQ means that the only non-market street lighting customers are in Ergon Energy's network area.

For these reasons, the Authority considers that it should continue to use Ergon Energy's network tariffs as the basis for regulated tariffs for large customers and street lighting.

The Authority's approach is consistent with the requirement in the Delegation to consider using Ergon Energy's network tariffs when setting notified prices for large customers, and the Government's submission supporting this approach suggests the Authority has correctly interpreted the intent of the Delegation and the UTP.

The Authority agrees with CCIQ that small customers in Ergon Energy's network area will not pay fully cost-reflective prices (because these will be based on Energex network tariffs) while large customers' charges will be broadly cost-reflective (being based on Ergon Energy network tariffs). However, this does not mean that large customers are cross-subsidising small customers. As large customers are not being charged more than their actual costs, they are not subsidising any other user. Rather, taxpayers generally are subsidising small customers via the Government's CSO payment to EEQ and, to a lesser extent, they continue to subsidise the electricity costs of many large customers in Ergon Energy's network area as well.

While most large customers in Ergon Energy's network area will pay (roughly) their full costs of supply, this is not the case for all large customers. Ergon Energy has a set of network tariffs for each of its three pricing zones to reflect the differing distribution costs of supply in each zone (East, West and Mt Isa). Within each pricing zone, there are more regions identified across which TUOS charges differ.

The UTP requires the Authority to choose one set of network charges. As it did for 2012-13, the Authority has based notified prices for large customers on the network charges for Ergon Energy's East pricing zone, on the basis that it includes almost 90% of Ergon Energy's large customers, and Transmission Region one, on the basis that these transmission charges are similar to the average TUOS charges in the East zone. As network charges in Ergon Energy's East pricing zone are generally lower than elsewhere in its network area, an implication of this approach is that large customers on notified prices outside the East pricing zone (and Transmission Region one) will still be paying less than their actual cost-reflective network charges. While this could cause an alternate retailer to incur losses supplying large Ergon Energy customers outside the East pricing zone at notified prices, in practice, this is likely to be an issue only for EEQ, which recoups such losses via the CSO payment from the Government. The Authority notes that no retailers objected to this approach.

An unavoidable outcome of basing notified prices for small customers on network costs in the Energex area and for large customers on network costs in the Ergon Energy area is the potential for significant differences in bills for customers either side of the 100 MWh threshold, as noted by Mr Brimblecombe. However, this simply demonstrates the extent to which the current policy framework for notified pricing favours small customers in regional Queensland.

Nevertheless, the Authority acknowledges that basing notified prices for large customers on Ergon Energy's network tariffs may result in significant price impacts for some customers and this issue is considered further in determining transitional arrangements in Chapter 6. However, the reality is that, for most large customers, these price impacts arise mainly because of the favourable prices customers have been able to access on (what are now) obsolete tariffs that do not reflect the actual costs of supply, either in terms of the structure of the underlying network costs or the overall level of the charges.

It was made clear at the Authority's regional workshops that a key issue of concern for large customers was the absence of off-peak pricing in any of Ergon Energy's network tariffs. It is disappointing that this is the case and that Ergon Energy has no plans to implement revised network tariffs (should it decide changes are required) until 2014-15. While network pricing is a matter for Ergon Energy and the AER, the Authority considers that some steps in this direction could have been implemented ahead of Ergon Energy's current review of network pricing by incorporating some time-of-use signalling in both energy and demand charges for 2013-14. The Authority would also encourage Ergon Energy to explore more innovative network pricing that is aimed at more than simply recovering costs, for example, by recognising assets at risk of being stranded if customers decide to pursue non-network energy supply arrangements.

2.3.2 Very Large Customers

As the Authority has noted previously, a key difficulty in setting notified prices for very large customers (those consuming more than 4 Gigawatt hours (GWh) per year) is that Ergon Energy has confidential, individually tailored network charges that reflect the unique circumstances of each customer in this diverse group. In setting 2012-13 notified prices, the Authority considered that it was not feasible to base notified prices on the approved (individual) network charges for these customers at that time. Instead, the Authority based the regulated retail tariff (Tariff 48) for very large Ergon Energy customers on the same network tariff (for high voltage demand customers) that Tariff 47 is based on. Ergon Energy supported a continuation of this approach for 2013-14.

Some stakeholders, including Sucrogen, Toowoomba Regional Council, Queensland Cotton and Cotton Australia, expressed concern about the potential impact of moving to notified prices based on individually calculated network prices. Sucrogen suggested that such an approach would be inconsistent with the Government's UTP. Queensland Cotton and Cotton Australia suggested that site-specific network charges would have a significant impact on many large regional businesses that must be located where they are in order to service particular industries.

Ergon Energy supported the continuation of a transitional regulated retail tariff for very large customers in light of the significant cost impacts from paying retail electricity prices based on their site-specific network charges. Ergon Energy agreed with the continued use of the SAC high voltage demand network tariff (EDHT1) as the basis for setting the regulated retail tariff for Ergon Energy's very large customers (Tariff 48).

On 4 September 2012, the Minister issued a Direction to the Authority under section 253AA of the Electricity Act requiring it to provide advice on the impact on very large customers of paying retail electricity prices based on their site-specific network charges and whether these site-specific network charges should be passed through to very large customers and how. The advice, which the Authority provided to the Minister on 30 November 2012, is available on the Authority's website. In summary, the Authority found that:

(a) a majority of very large customers would experience significant increases in their annual bills if they were to move to retail prices based on their site-specific network charges, although some would be better off;

(b) passing through site-specific network charges to very large customers would enhance the cost-reflectivity of retail tariffs which would promote competition and encourage more efficient use of electricity;

(c) while it would be possible to determine notified prices based on site-specific network charges, it is unclear whether this would be consistent with the Government's UTP; and

(d) cost-reflectivity may be better achieved if access to notified prices was removed and very large customers were required to move to a market contract (as has already occurred in the Energex area), with any transitioning issues addressed by, for example, direct Government subsidy on an individual customer need basis.

The Minister responded to the Authority's advice on 22 January 2013 and advised that the Interdepartmental Committee (IDC) for Electricity Sector Reform would consider the Authority's advice before providing recommendations to the Government in early 2013. Given this, the Authority has decided to continue with the approach it used to set notified prices for very large customers in 2012-13. While this creates an added degree of uncertainty in relation to pricing for very large customers, the Authority notes that the transitional arrangements proposed in Chapter 6 provide customers with some degree of pricing certainty in the short term while the longer-term approach for very large customer pricing is developed.

2.4 The Authority's Final Determination

The Authority's Final Determination is to base regulated retail tariffs for 2013-14 on:

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

(b) Energex network tariffs and charges for all other customers, including other unmetered loads.

The resulting network charges to be used as the basis for regulated retail tariffs for 2013-14 are as shown in Tables 2.2 – residential customers, Table 2.4 – other small customers and unmetered supplies (other than street lighting), and Table 2.6 – Ergon Energy's large customers consuming more than 100 MWh per year and street lighting.

2.5 Alignment of Retail and Network Tariffs

Using an N+R approach to setting notified prices requires a formal process to ensure the ongoing alignment of network and retail tariffs to ensure the appropriate allocation of costs to (and recovery of costs from) groups of customers covered by each tariff class. Maintaining this alignment would also ensure that distributors are able to engage in effective demand management initiatives that rely on correct price signals being passed through to customers.

Under the NER, the distributors are normally required to submit proposed network prices by the end of April each year. However, the Authority was required to publish its 2013-14 Draft Determination by 22 February 2013. As a result, the distributors provided preliminary network prices to the Authority.

For subsequent years, the Authority must publish its Draft Determination by 15 December. Energex noted that key input data, such as forecasts of demand and customer numbers, transmission prices and under/over recoveries of network revenue, would not be available in time to set draft network prices by 15 December, and that Energex would have to rely on preliminary estimates of these. As a result, it will be likely that draft network prices provided for the purpose of setting draft notified prices will change before being approved by the AER.

There is also no formal limit on the time the AER can take to approve the distributors' pricing proposals, though this usually occurs after 31 May which is the date by which the Authority must publish final notified prices. As a result, any change in the network tariffs proposed by the distributors and approved by the AER after the Authority has published final notified prices would potentially result in a misalignment of network and retail tariffs.

In its September 2012 proposal to the AEMC, IPART proposed changes to the NER which included a requirement that network prices be set earlier to allow greater consultation on retail price changes and for customers to receive earlier notification of the change to their prices. If this rule change was adopted, it would improve the certainty of price setting for the Authority. However, this is yet to be considered by the AEMC.

In the Draft Determination, the Authority considered that the best option for setting 2013-14 prices would be to proceed as for last year and request Energex and Ergon Energy to supply the Authority with proposed network tariffs and prices when they are submitted to the AER in April and use these as the basis for notified prices to apply from 1 July.

There was broad support for this approach amongst those stakeholders that commented, although retailers suggested different ways that any differences between draft and final network prices should be accommodated. AGL suggested that notified prices should be updated within the year in which they apply if final network prices change. In contrast, Ergon Energy suggested that there should be a catch-up mechanism, and that if there was not one, then an appropriate adjustment should be made to the margin. EnergyAustralia also suggested that, if the Authority could see no practical way around having to use draft network prices to set notified prices, then it would be appropriate to allow a higher retail margin to compensate retailers for the additional risk they face as a result.

Most of these concerns should be addressed by the Authority's decision to include a cost pass-through mechanism in notified prices, as discussed in Chapter 5.

As envisaged in the Draft Determination, the Authority has based its notified retail prices for 2013-14 on the distributors' network tariffs as submitted to the AER for approval in April 2013. In the event that the final network tariffs approved by the AER depart from those used here, the Authority will consider using the pass-through mechanism to adjust for any material difference when setting notified prices to apply during 2014-15.

3. ENERGY COSTS

Energy costs are those a retailer will incur, either directly or indirectly, in supplying energy to cover the load of its customers. In previous decisions, the Authority has included allowances for a range of energy costs, which can be broadly broken into three categories:

(a) wholesale energy costs;

(b) other energy costs, including green schemes and market fees; and

(c) energy losses.

The most significant and contentious cost component is the wholesale energy cost. In this Final Determination, the Authority has retained the market-based approach to estimating wholesale energy costs that it proposed in its Draft Determination.

The Authority has also retained its proposed approaches for estimating other energy costs and applying energy losses.

3.1 Requirements of the Electricity Act and Delegation

In determining the energy costs faced by retailers, section 90(5) of the Electricity Act requires the Authority to have regard to:

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

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

(c) any matter required under the Delegation; and

(d) any other matter the Authority considers relevant.

The Delegation requires the Authority to consider whether its approach can strengthen or enhance the time-of-use signals in the underlying network tariffs to encourage customers to switch to time-of-use tariffs and reduce their consumption in peak times.

3.2 ACIL Tasman's advice

The Authority engaged ACIL Tasman (ACIL) to provide advice on each energy cost component in accordance with the terms of reference for its engagement (available on the Authority's website). The Authority is of the view that retaining the same consultant for this review as it has retained in prior years will provide continuity and certainty to stakeholders. ACIL has now prepared four reports as part of this review:

(a) a preliminary draft report[8] outlining its proposed methodology for estimating energy costs, which was released along with the Authority's consultation papers;

(b) a draft report[9] outlining its consideration of issues relating to energy costs raised in stakeholder submissions to the consultation papers, discussion of its preferred

[8] ACIL Tasman, *Estimated Energy Costs for Use in 2013-14 electricity retail tariffs – preliminary draft report*, December 2012 – can be accessed at www.qca.org.au.
[9] ACIL Tasman, *Estimated Wholesale Energy Costs for 2013-14 retail tariffs - draft report*, February 2013 – can be accessed at www.qca.org.au

approach to estimating energy cost allowances and draft estimates of the energy cost components for 2013-14;

(c) a response to Frontier Economics' commentary[10] on ACIL's approach[11] outlining why its market-based approach is the most appropriate methodology for estimating energy costs for retail tariffs; and

(d) a final report[12] outlining its consideration of issues raised in submissions to the Draft Determination, discussion of its approach to estimating energy cost allowances and final estimates of the energy cost components for 2013-14.

3.3 Wholesale Energy Costs

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

For its 2012-13 Determination, the Authority considered three alternative approaches for determining wholesale energy costs, including a hedging-based model, long run marginal cost (LRMC) and a statistical model that estimated the price a retailer might be willing to pay to enter hedging contracts (the Price Distribution approach). The Authority also considered how it might take into account PPAs held by retailers. While each approach had its merits and drawbacks, the Authority decided that the hedging-based approach was the most appropriate on the basis that it was based on publicly available data, it was intuitive and it was known and (largely) accepted as a reasonable approach by stakeholders.

3.3.1 Judicial Review

Following release of the Authority's 2012-13 Final Pricing Determination, Origin Energy made an application for Judicial Review of aspects of the Authority's approach to estimating energy costs in that decision. On 19 December 2012, the Supreme Court dismissed Origin Energy's application.

In its submission to this current review, Origin Energy has suggested that the outcome of the Judicial Review does not lock the Authority into using the hedging approach in subsequent years.

As in the past, the Authority has considered all arguments presented in submissions before deciding on the most appropriate method to use for the coming year.

3.3.2 Potential Approaches for 2013-14 to 2015-16

In its consultation papers and Draft Determination, the Authority identified three potential approaches to estimating wholesale energy costs, including an LRMC approach that would estimate the cost of generation, a market-based approach that would estimate the cost a retailer would face in hedging energy purchases from the NEM, and a statistical approach

[10] Frontier Economics, *Commentary on ACIL Tasman's approach for measuring energy costs*, March 2013 - can be accessed at www.qca.org.au
[11] ACIL Tasman, *ACIL Tasman's methodology for estimating energy costs – Response to commentary by Frontier Economics*, April 2013 – can be accessed at www.qca.org.au
[12] ACIL Tasman, *Estimated wholesale energy costs for 2013-14 retail tariffs – final report*, May 2013 – can be accessed at www.qca.org.au

that would estimate the price a retailer might be willing to pay to enter hedging contracts (the Price Distribution approach).

While the Authority acknowledged some of the concerns raised by retailers, who generally preferred an LRMC approach, it made clear its preference for using a market-based approach for estimating wholesale energy costs for the 2013-14 to 2015-16 Determinations.

Approaches in Other Jurisdictions

For its 2010-11 to 2012-13 retail electricity pricing decision for New South Wales[13], IPART used a hedging-based approach to estimate energy purchase costs and was required by its terms of reference to include an LRMC floor price. For 2013-14 to 2015-16[14], the terms of reference provided to IPART has reduced the influence that LRMC will have on regulated retail prices by requiring the energy cost floor price to be a weighted average of market-based costs (25%) and LRMC (75%). Even with the lower weight placed on LRMC, IPART estimated in its draft determination for 2013 to 2016 that its wholesale energy costs are between $9 to $14/MWh higher than they would be if it based them solely on efficient market-based costs.

In its decision on retail electricity prices in the Australian Capital Territory (ACT) for 2010-2012[15], the Independent Competition and Regulatory Commission (ICRC) developed a model for estimating energy costs based on corporate finance concepts rather than a hedging strategy. This reflected the ICRC's concerns about the nature of the NEM, which made it impossible to perfectly hedge.

In deciding on this approach for 2010-12, the ICRC noted that there were a number of reasons why the LRMC should not be used to estimate energy purchase costs. Amongst other things, the ICRC noted that the suggestion that generators would benefit from higher energy cost allowances in regulated retail tariffs, as a result of including LRMC in the calculation, was unproven and that higher energy cost allowances would not flow upstream to generators unless the retailer was altruistically supporting its suppliers. Furthermore, the ICRC considered that regulated retail prices should not be used to attempt to correct concerns about the long-term investment in electricity generation.

In its June 2012 final report, the ICRC confirmed that it would continue to use this approach for its 2012-13 to 2013-14 Determination[16].

Due to insufficient liquidity in the contract market at the time, the Essential Services Commission of South Australia (ESCOSA) used a hybrid cost-based and market-based approach to estimate energy costs in its price determination for 2011-12 to 2013-14[17]. Specifically, ESCOSA developed low and high estimates of LRMC to provide a price floor and price ceiling for its market-based energy cost estimate, which was based on a weighted average of market contract prices.

Given uncertainty over carbon pricing had dissipated and trading in hedging contracts had increased significantly, ESCOSA initiated a review of its wholesale energy cost estimates in July 2012. In October 2012, it published a Draft Determination outlining a proposal to recalculate wholesale energy costs using a market-based approach. However, this review

[13] IPART, *Review of Regulated Retail Tariffs and Charges for Electricity 2010-2013, Final Report*, March 2010.
[14] IPART, *Review of regulated retail prices for electricity, 2013 to 2016, Draft Report*, April 2013.
[15] ICRC, *Final Decision, Retail Prices for Non-contestable Electricity Customers 2010-2012*, June 2010.
[16] ICRC, *Retail Prices for Franchise Electricity Customers 2012-14, Final Report*, June 2012.
[17] ESCOSA, *2011-2014 Electricity Standing Contract Price Determination – Wholesale Electricity Cost Investigation, Determination of Special Circumstances Statement of Reasons and Draft Standing Contract (Further Variation) Price Determination*, October 2012.

was suspended subsequent to the South Australian Government announcing its plans to deregulate the retail electricity market from February 2013.

In estimating energy costs for Western Australia for 2012-13 to 2015-16[18], the Economic Regulation Authority (ERA) considered both the LRMC of generation and the costs that the incumbent retailer, Synergy, was likely to incur over the determination period based on the PPAs that it had entered into. ERA determined that wholesale energy costs should be based on the lower of the LRMC of new generation and the price at which existing generators are selling electricity. On this basis, ERA decided to use the LRMC of generation for its wholesale energy cost estimates for 2012-13 to 2015-16.

Submissions

Submissions responding to the Authority's consultation papers and Draft Determination were split on the most appropriate method for estimating wholesale energy costs.

Consumers, consumer groups and Stanwell supported the continuation of the Authority's proposed market-based approach on the basis that it was transparent, based on publicly available information and reflective of retailers' costs.

A number of retailers, the Energy Supply Association of Australia (ESAA) and the Energy Retailers Association of Australia (ERAA) raised concerns with the market-based approach suggesting that:

(a) the actual costs incurred by retailers could not be estimated without consideration of the PPAs and/or generation assets that retailers have entered into and/or built;

(b) the lack of liquidity in the futures market might affect the reliability of ACIL's wholesale energy cost estimates. AGL and Origin Energy also suggested that, as the volume of 2013-14 futures traded to date was less than the retailers' total small customer load, futures prices would be considerably higher if retailers attempted to purchase all of this load through the futures market;

(c) the approach lacked transparency, particularly in regards to load and spot price forecasts; and

(d) the market-based approach would lead to volatility and potentially very high prices for consumers if or when demand outstrips supply in the generation market. Origin Energy suggested that price volatility creates hardship for customers and leaves retailers open to the risk that the Authority or Government could switch away from the market-based approach when the generation market tightens.

To address these concerns, retailers generally suggested that the Authority consider a mix of LRMC, PPA and market-based approaches, through an LRMC floor or a weighted average of short and long-term contracts.

While Simply Energy suggested that ACIL's market-based approach would provide efficient energy cost estimates, it argued that the Authority should not be using efficient costs for the purpose of setting retail tariffs. It was of the view that efficient costs were appropriate to use when regulating a monopoly but that, in a competitive market such as the retail electricity market, prices should be set as a 'safety net'. It was of the view that the Authority should adopt the higher of the LRMC and market-based approaches in order to ensure sufficient headroom for new entrant retailers to compete.

[18] ERA, Synergy's Costs and Electricity Tariffs, Final Report, July 2012.

Despite its earlier preference for an LRMC floor, AGL concentrated its efforts since the Draft Determination on improving the market-based approach and now suggests that the market-based approach would provide reasonable energy cost estimates if its remaining concerns relating to load and spot price forecasts could be addressed.

QEnergy and Origin Energy also provided the Authority with confidential information on their various hedging arrangements. These confidential submissions included largely the same information provided to, and considered by, the Authority during its 2012-13 pricing review. QEnergy noted that, under the Electricity Act, the Authority could request similar information from other retailers and Origin Energy suggested that the Authority could take account of related party transactions, including testing them for efficiency, by adopting the PPA valuation method AGL suggested in its supplementary submission to the 2012-13 Draft Determination.

Submissions also raised a number of technical concerns about aspects of ACIL's methodology. These matters are discussed below in Section 3.3.3 and in more detail in ACIL's final report.

The Authority's Position

The Authority has considered this issue in detail in numerous papers and forums and there is little new in the arguments made by retailers to include LRMC in the Authority's approach this year. In fact, a number of retailers appear to be acknowledging the potential for the market-based approach to provide reasonable energy cost estimates.

The Authority has previously stated its views in relation to many of the arguments raised by retailers to support the inclusion of at least some aspects of LRMC estimates in calculating energy purchase costs, including that:

(a) LRMC is an estimate of long-term generation costs rather than the cost to a retailer of purchasing wholesale electricity in the forthcoming year;

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

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

(d) adopting an estimate of LRMC as an energy cost "floor" suggests that notified prices should be set at a level which underwrites generation, which is not one of the requirements established by the Delegation; and

(e) including LRMC in retail tariffs effectively provides a regulated return to vertically integrated generators, which would provide them with an unfair advantage over stand alone generators, that are required to earn their returns through the competitive NEM.

As the Authority noted previously, while adopting an LRMC floor in notified prices might provide additional security for investment in generation, the Authority is of the view that this is unnecessary given current market conditions as there appears to be sufficient reliable information available in the market for a firm to make a timely and efficient decision about investing in generation in the NEM. The Authority has also questioned why this increased security would be needed with regulated prices but not if the market was entirely deregulated.

The Authority acknowledges that, while in some years regulated prices set on a market-based approach could be less than the actual costs faced by retailers (including the costs of PPAs), the reverse may equally be true in other years. Indeed, retailers have pointed to such a scenario when they have claimed that the market-based approach would lead to volatility and potentially very high prices for consumers if demand outstrips supply in the generation market.

ACIL has undertaken additional analysis[19] to illustrate the significant variation in its load and spot price forecasts. ACIL's load forecasts provide a varied range of outcomes for 2013-14. While the upper bound of these forecasts is lower than the actual load in 2009-10, ACIL suggests this is reasonable given the structural changes that have happened to the Net System Load Profile (NSLP) in recent years, including the exit of large customer load, energy conservation measures by households and a shift of the NSLP peak from afternoon to evening. Similarly, ACIL's spot price forecasts (462 scenarios) reflect a range of potential outcomes for 2013-14 that have considerably more variability than has been seen in the NEM to date. The Authority considers that this analysis should address AGL's remaining concerns with the market-based approach.

The Authority disagrees with Simply Energy's view that headroom should be built into energy cost estimates by setting energy costs at the higher of the LRMC or market-based approach. To the extent that retail tariffs may require headroom in order to promote competition, the Authority considers that this is best achieved through an explicit allowance on top of costs rather than implicit in cost categories. For this reason, the Authority tasked ACIL with estimating actual costs for 2013-14 rather than the headroom-inclusive costs that Simply Energy has suggested would be more appropriate.

If it were expected that the market-based approach preferred by the Authority would systematically under-estimate energy costs, there would be little or no discounts to the regulated prices available in the market place and competition would not be vigorous. However, while customer switching has slowed, retail discounts continue to be offered by a number of retailers, up to 13% off a typical residential bill.

The Authority also questions why some retailers would propose the (re)introduction of an approach based on a weighting of LRMC and market-based costs, given the widespread dissatisfaction expressed by retailers with the use of such an approach when it was required under the BRCI.

Over the long term, the application of the Authority's preferred market-based approach should deliver similar returns to retailers as an approach based on LRMC. However, in any individual year, the Authority's market-based approach will produce price estimates more in line with actual market conditions, and hence pass appropriate signals to consumers regarding the cost of their current consumption, while (except by coincidence) an approach based on LRMC will not. Origin Energy suggested that this may leave retailers vulnerable to the Authority changing its approach or Government changing its delegation in years when the market price is higher than LRMC. While the Authority has no control over the content of future delegations, the market-based approach has been its favoured approach for a number of years and, based on the views outlined above, it is unlikely that the Authority would change methodology in the future unless required to by legislation or delegation. The Authority is not convinced that the inclusion of LRMC in any form in the estimation of energy costs is warranted or necessary and maintains its view that a market-based approach should provide the best estimate of the costs that retailers will incur in the year ahead. ACIL shares this view and has recommended that the Authority adopt a market-based approach for estimating wholesale energy costs for 2013-14.

[19] ACIL Tasman, *Estimated wholesale energy costs for 2013-14 retail tariffs – final report*, May 2013.

The Authority has therefore decided to continue to apply a market-based approach to estimating energy costs for 2013-14.

3.3.3 The Market-based Approach

Stakeholders made a number of suggestions about how the market-based approach might be improved for 2013-14. ACIL has addressed these issues in further detail in its final report.

Including PPAs in the Market-based Approach

A number of retailers suggested that the market-based approach could be improved by including either the actual PPAs held by retailers, or a valuation of these PPAs and that the Authority cannot estimate the actual costs faced by retailers if it ignores this significant component of most retailers' hedging strategies. This view was also supported by Frontier Economics in a commentary on ACIL's approach submitted by the ESAA (both the Frontier Economics paper and a detailed response by ACIL have been released on the Authority's website).

Two of the main benefits of the market-based approach are its reliance on publicly available information and its transparency which would be severely reduced under an approach relying on PPAs. While the Authority could require all retailers to provide details on every PPA they have entered into, retailers would almost certainly consider this information commercially sensitive and not to be published, but the Authority may form a different view. An important attraction of the market-based approach is the availability of necessary information in the public domain. This at least provides a reasonable degree of transparency (probably more useful for retailers than consumers) over the inputs to what is, of necessity, a complex and less transparent modelling process. Interweaving into that process confidential information on PPAs or the costs of generation (not that the Authority could require generators (as opposed to retailers) to provide information) would only reduce the ability of all stakeholders to assess, understand and accept the modelling outcome.

In its final advice to the Authority for 2012-13, ACIL also noted that, as PPAs are designed to provide a stable long-term return to the asset owner, the PPA price would not be expected to exceed the cost of purchasing energy through a combination of the electricity pool and electricity hedges over the life of the PPA. ACIL expected that, while the PPA price might be higher than the market price in some years, it would also be lower in other years and, on average, no higher than the market price over the term of the PPA. On that basis, ACIL suggested that the market price over the term of a PPA would be expected to provide a ceiling to a well-priced PPA.

Further to this, in its response to Frontier Economics' commentary on its approach, ACIL noted that, if it were required to take account of PPAs in its market-based approach, it would be most appropriate to value them according to the prevailing market prices (that is, the same d-Cypha futures prices that ACIL has used to estimate energy costs).

Liquidity in the Futures Market

Despite retailers' concern regarding the current level of liquidity in the futures market, ACIL has indicated it is satisfied that the volume of futures trading is sufficient to provide robust and accurate forecasts for 2013-14. As anticipated in the Draft Determination, the volume of trades has continued to increase leading up to this Final Determination.

Ergon Energy was concerned that the lack of liquidity in the futures market meant that ACIL's approach might be sensitive to a single large trade. As such, it suggested that ACIL consider returning to a time-weighted average of futures prices (as used under the BRCI) rather than the trade-weighted average ACIL now uses. However, ACIL considered that a trade-weighted average best reflects the market price of energy purchased and that a time-weighted average would be inappropriate because it would skew prices towards periods in which no trades occurred.

The suggestion by AGL and Origin Energy that futures prices would be higher if retailers purchased all of their small customer load through that market, ignores the fact that market outcomes are a function of both demand and supply. If retailers were to purchase all of their load through the futures market, generators would also be selling all of their load through the futures market. The one change would most likely be offset by the other. Moreover, since futures prices are fundamentally linked to the outcomes of the spot market, if it were the case that futures were systematically trading at levels higher than the expected outcomes of the spot market, speculators would enter the market to increase supply and bring prices down to expected levels.

Recent Volatility in the Electricity Market

In its submission to the consultation papers, Origin Energy suggested that volatility in the market would put undue risk onto retailers if retail prices were determined using a market-based approach. The Authority disagrees. Prudent retailers undertake their hedging over a number of years up to the relevant period and are therefore largely protected from price spikes (such as those experienced in December 2012 and January 2013). Moreover, in comparison to Origin Energy's preferred LRMC approach, the market-based approach is better equipped to deal with these types of short term market movements because they are included in the modelling process.

Historic and Forecast Customer Load

A number of stakeholders commented on ACIL's process for sampling and forecasting customer load.

ACIL uses historic load (2009-10, 2010-11 and 2011-12) for each settlement class and each region in the NEM as an input to its wholesale energy market modelling. Stanwell questioned whether the net system load profile (NSLP) over the last three years (particularly 2009-10) will provide a fair representation of the NSLP in 2013-14 given the strong growth in PV generation that has flattened the NSLP over the last couple of years. Similarly, a number of retailers noted the higher maximum demands and more volatile weather patterns in years prior to 2009-10 and recommended that ACIL increase the number of years of actual data used to reflect the higher maximum demands and more volatile weather patterns in these years.

Irrespective of the historic load used, a number of retailers expressed concern that the spread of potential load outcomes ACIL has forecast for 2013-14 was not reflective of the potential demand outcomes for the year. AGL suggested that the spread did not reflect a reasonable spread of outcomes because the maximum demand over the 42 scenarios was lower than the maximum demand associated with the NSLP recorded in 2009-10.

ACIL has responded to stakeholders' concerns in its final report and believes its approach suitably accounts for these issues. It is satisfied that its approach for developing and growing historic load to reflect 2013-14 demand suitably accounts for the relatively mild weather over recent summers and covers the range of likely outcomes for 2013-14. ACIL acknowledges that the NSLP forecasts do not achieve the maximum demand from the 2009-10 summer, but suggests this reflects a number of structural changes to the NSLP over that period including:

(a) large customers leaving the NSLP and being settled against interval meters (as has been suggested by Origin Energy a number of times);

(b) energy conservation initiatives leading to lower consumption by households; and

(c) the shift of the NSLP peak from early afternoon to early evening, potentially caused or amplified by the strong growth in domestic PV energy generation.

ACIL has considered which load forecasts are the most appropriate to use in its modelling for 2013-14. At the 19 December 2012 workshop in Brisbane, ACIL presented some of its preliminary modelling results[20] to illustrate the large impact and, as AGL pointed out in its submission to the consultation papers, potentially unrealistic outcomes that can result from adopting the wrong load forecasts. ACIL is of the view that using the Australian Energy Market Operator's (AEMO's) low economic growth forecast is most appropriate for 2013-14, given the current economic outlook.

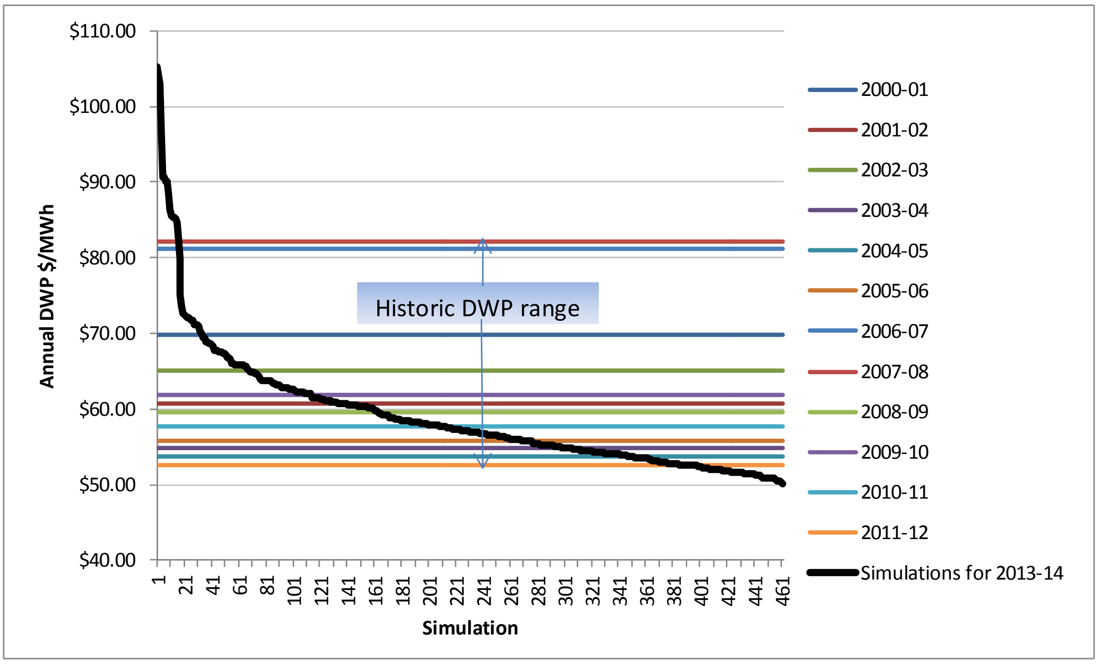
Spot price forecasts and hedged outcomes

A number of retailers were concerned that ACIL's spot price forecasts did not reflect the variability or risks that might be expected for 2013-14. In particular, AGL suggested that the 462 spot price scenarios were not credibly variable and a number of retailers remarked that the spot prices relating to the 95th percentile of the hedged outcomes were not reflective of a one-in-20 year outcome.

ACIL has provided considerable analysis of its spot price forecasts in its final report. As illustrated in Figure 3.1, ACIL's 2013-14 demand-weighted spot price forecasts (DWP in Figure 3.1) comfortably cover the spread of demand-weighted price outcomes experienced in the NEM over the last 12 years. AGL did not outline what spread of spot price outcomes it thought would be considered credible. The Authority is of the view that ACIL's approach has provided a reasonable spread of spot price outcomes for 2013-14.

[20] ACIL's presentation from the workshop is available on the Authority's website.

Figure 3.1: Annual demand-weighted spot prices for Queensland for the 462 simulations for 2013-14 compared with the annual demand-weighted spot prices recorded in past years

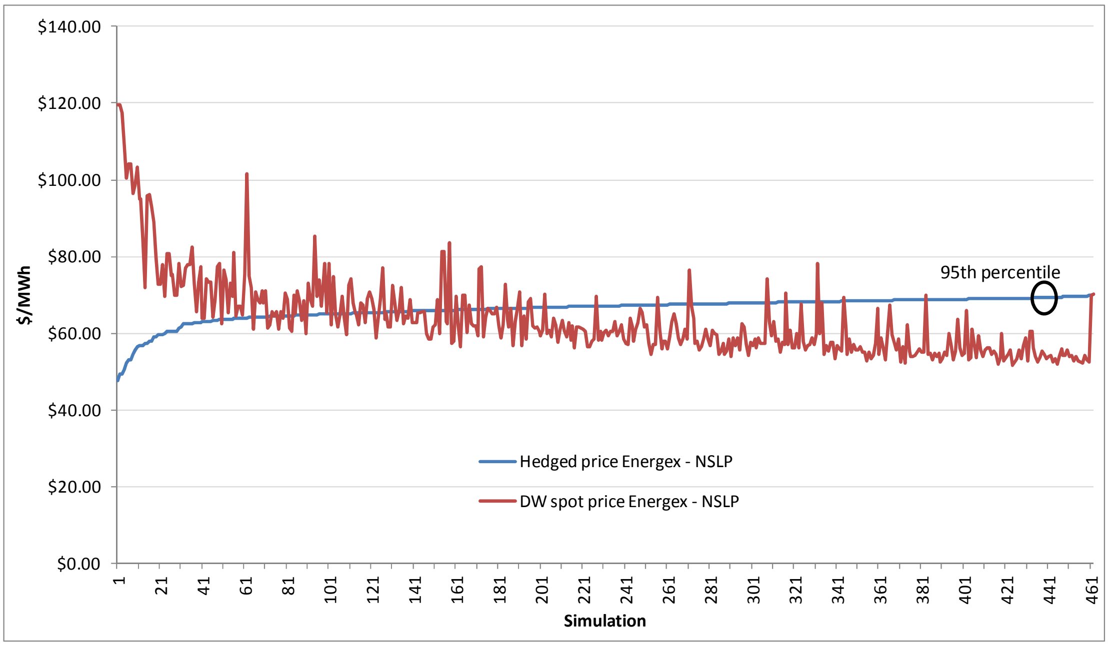


Source: ACIL Tasman, Estimated wholesale energy costs for 2013-14 retail tariffs – final report, May 2013.

In its final report, ACIL also explains that the spot prices for the 95th percentile of the hedged costs are not reflective of a one-in-20 year outcome because of the inverse relationship between spot price outcomes and hedged costs (illustrated in Figure 3.2). As supported by most stakeholders, the conservative hedging strategy ACIL adopts generally leads to an over-hedged position. This means that in periods of high demand and spot prices, retailers are unlikely to be left unhedged.

Being over-hedged at a time of high spot prices leads to considerable windfalls through contract settlement, which is reflected in the generally lower hedged costs in years with high load-weighted spot prices. However, this level of protection comes at a cost and, in periods of low demand and spot prices (as might well be the case in 2013-14), the cost to a retailer is high. As can be seen in Figure 3.2, the 95th percentile of hedged costs relates to a relatively low load-weighted spot price.

Figure 3.2: Annual hedged and demand weighted spot prices for Energex NSLP for the 462 simulations ($/MWh)



Source: ACIL Tasman, Estimated wholesale energy costs for 2013-14 retail tariffs – final report, May 2013

On the basis of the analysis ACIL has provided in its final report, the Authority is satisfied that ACIL's spot price forecasts provide a reasonable estimate of the potential spot prices that might be expected in 2013-14.

Additional Allowances for Risk

In its submissions to the consultation papers, QEnergy suggested that, if the Authority adopts a market-based approach based solely on futures contracts, then it must account for a variety of additional risks and costs in order to account for the true costs of a retailer. This would include additional allowances for:

(a) Time risk, which QEnergy noted ACIL had proposed to include in its Price Distribution approach prepared for the 2012-13 Draft Methodology Report.

However, the time risk that ACIL proposed for the Price Distribution approach was designed to account for the higher prices that contracts with longer tenors typically achieve in the market. As noted by AGL in its submission, valuations increase as the tenor of the instrument increases. Given that ACIL is using actual futures trades for its market-based approach – as opposed to estimating the price that retailers might be willing to pay for the Price Distribution approach – the time risk premium is already built into the futures prices.

(b) Shape risk, to account for the peaky nature of the NSLP.

While the Authority understands that the NSLP is peaky and accepts that some retailers may adopt a strategy that minimises risk through purchasing load shaped contracts, that strategy comes at a premium because the retailer has traded off risk for price. Similarly, some retailers might adopt a more risky strategy that comes at a lower price. The analysis provided by ACIL at the Brisbane workshop which outlined the spread of hedged costs under ACIL's 462 scenarios for 2013-14 suggests that its hedging strategy provides reasonable protection against the peakiness of the NSLP.

(c) Load risk, to reflect the risk that customer volumes and wholesale prices might increase simultaneously.

Load risk is faced by all retailers. To cover retailers for events where customer volumes and wholesale prices increase simultaneously, ACIL's hedging strategy assumes that a retailer purchases cap contracts up to 105% of maximum forecast demand each quarter. Further to this 'over hedging', to account for residual volume (and price) risk in its hedging strategy, ACIL has proposed to use the 95th percentile of the hedged outcomes rather than the median, as it did for 2012-13 (this is discussed further below).

(d) Prudential capital – to cover the additional bank guarantees that a retailer would have to purchase if it hedged using futures that it would not otherwise require if it hedged through other means such as PPAs or investing in generation.

The Authority considered this issue in its 2012-13 review in the context of retail operating costs and at that time considered that these were likely already accounted for in the retail operating cost estimate. However, following further consideration of the issue raised in submissions this year, the Authority is now of the view that these costs may not be included in the benchmarked retail operating costs and that it might be appropriate to account for these prudential costs in the context of estimating the cost of energy. This issue is discussed further in Section 3.4.4 below.

Enhancing Time-of-Use Signals

The Delegation requires the Authority to consider whether its approach to estimating energy costs could strengthen or enhance the underlying network price signals and provide greater incentives for customers to switch to time-of-use tariffs and reduce their energy consumption during peak times.

At the outset of the 2012-13 Review, the Authority considered developing energy cost estimates that would include time-of-use signals to consumers. However, retailers pointed out that this did not reflect the way in which they are charged for electricity by AEMO, which is based on the relevant distributor's NSLP.

Submissions in response to the Authority's consultation papers and Draft Determination were broadly supportive of the inclusion of time-of-use signals in wholesale energy costs, but only to the extent that they could be implemented on a cost-reflective basis. Stakeholders were against including artificial time-of-use signals in the wholesale energy costs without regard to AEMO's settlement procedure. Ergon Energy also raised concerns that time-of-use signals might not be cost-reflective if the timing of peak, off-peak and shoulder periods in the underlying network tariffs did not align with the peak and off-peak times in the NEM.

In its submission to the consultation papers, QCOSS suggested that an amendment to AEMO's Metrology Procedures could allow customers who already have electronic meters (not accumulation meters) to be settled against their individual consumption and hence priced according to their time-of-use. QCOSS suggested that this change could be implemented ahead of any blanket roll-out of smart meters. This proposal was supported by a number of stakeholders in their responses to the Draft Determination.

Amending the Metrology Procedures is a matter for the Queensland Government to decide and initiate with AEMO, not something over which the Authority has any control. This may be something the Government could explore further with AEMO in the coming year.

Regardless, any changes along these lines would take time and would not be possible to implement for inclusion in wholesale energy costs for 2013-14.

A key concern expressed in submissions regarding this issue was the shrinking differential between peak and off-peak rates in Tariff 22 in 2012-13 or, more particularly, the increase in the available off-peak rate. However, even if it were inclined to do so, the Authority notes that differentials seen in Tariff 22 in 2011-12 (and prior years) could not be recaptured solely through time-of-use signals incorporated in the energy costs because they do not make up a large-enough component of the (total) retail tariff, as outlined in Table 3.1. For this reason, the bulk of any time-of-use signals in retail tariffs must come through the underlying network tariffs as they make up, by far, the largest component of retail tariffs.

Table 3.1: Potential Time-of-use Components in 2013-14 Variable Rates

Component	*Off peak*		*Peak*		*Potential for time-of-use signals*
	c/kWh	*% of total*	*c/kWh*	*% of total*	
2011-12 Tariff 22	9.92	NA	28.17	NA	
2013-14 Tariff 22					
Network	9.014	48%	15.841	62%	Yes, but up to network businesses
Wholesale energy (ex carbon)	5.704	31%	5.704	22%	Yes, but requires amendment to AEMO metrology procedures
Carbon costs	2.590	14%	2.590	10%	Yes, but requires amendments to AEMO metrology procedure and would result in higher off-peak prices due to the higher carbon intensity of off-peak
RET and other costs	1.361	7%	1.361	5%	No basis for time-of-use signals
Total	18.668	100%	25.496	100%	

Note: Margin and headroom allocated to each cost component to reflect the way costs are derived for retail tariffs.
Sources: The Authority's workings and ACIL Tasman, Estimated wholesale energy costs for 2013-14 retail tariffs – final report, May 2013

Using the 95th Percentile of Hedged Outcomes

In its preliminary report released along with the Authority's consultation papers, ACIL proposed to adjust its methodology slightly from that used in 2012-13 by basing its wholesale energy cost estimate on the 95th percentile of the 462 annual hedged prices, rather than the median (as it had for 2012-13). This adjustment was proposed in order to minimise any residual volume or price risk inherent in the modelling.

In response, QCOSS suggested that ACIL should further justify this decision and that any reduction in risk due to using the 95th percentile should be accompanied by a corresponding reduction in the retail margin. Stanwell suggested that a robust modelling process should be able to account for risk and that the median was most appropriate for use in 2013-14. Stanwell questioned whether the move to the 95th percentile was just for 2013-14.

Conversely, most retailers supported ACIL's proposal to use the 95th percentile, with Origin Energy suggesting that this still fell short of the one-in-100 year event for which it is covered.

In its final report, ACIL has reaffirmed its view that using the 95th percentile of hedged outcomes is most appropriate for 2013-14 on the basis that it takes into account the majority of risk faced by retailers. Given that ACIL has proposed using the 95th percentile to account for residual volume and price risk in the hedging strategy, the Authority anticipates that this approach will be adopted in future years. However, the Authority will consider ACIL's advice and any other information provided by stakeholders when preparing future price determinations.

The Authority is satisfied with ACIL's proposal to adopt the 95th percentile of hedged costs in 2013-14. While the proposal from ACIL may fall short of Origin Energy's own risk management process, it is largely in line with that of AGL, which only hedges against (up to) one-in-20 year events in recognition that the cumulative cost of hedging to higher levels of exposure would (in AGL's view) substantially exceed the potential losses[21].

Carbon Costs

In its preliminary draft report, ACIL proposed to retain the same approach to estimating carbon costs for 2013-14 as it used for 2012-13. This approach involved running two modelling scenarios, one with carbon costs and one without, to estimate how the carbon tax would affect the costs faced by retailers. The difference between the two scenarios was used as the cost allowance for carbon.

Submissions were generally satisfied with ACIL's approach to estimating carbon costs, so long as it would only be used as an indicative estimate of carbon costs for messages on customer bills. Stakeholders noted that ACIL's estimates would have to be reviewed if the carbon tax is subsequently removed and carbon exclusive wholesale energy costs are required.

Given the general support of stakeholders, ACIL has retained the 2012-13 approach in its final report.

3.3.4 2013-14 Carbon and Wholesale Energy Cost Estimates

Table 3.2 outlines ACIL's final carbon and wholesale energy cost estimates for 2013-14.

[21] http://www.agl.com.au/about/ASXandMedia/Pages/WeathereventsaffectAGL2011UnderlyingNPAT.aspx

Table 3.2: 2013-14 Carbon and Wholesale Energy Cost (Excluding Losses)

Settlement class	Retail Tariff	2013-14		Change from 2012-13[a]	
		Carbon Allowance[b]	Wholesale Energy Allowance (including carbon)	Carbon Allowance[b]	Wholesale Energy Costs (including carbon)
		($/MWh)	($/MWh)	(%)	(%)
Energex NSLP and unmetered supply	11, 12, 13, 20, 22, 41, 91	21.69	69.43	9.0%	12.9%
Energex Controlled Load 9000	31	21.81	47.06	3.4%	13.0%
Energex Controlled Load 9100	33	21.40	57.89	6.6%	18.3%
Ergon Energy NSLP and streetlights	44, 45, 46, 47, 48, 71	21.76	64.08	7.3%	14.6%

a. In 2012-13, the energy cost allowance didn't apply to Tariff 11 (as Tariff 11 was determined by the Minister) or Tariff 13 (as it is a new tariff for 2013-14).
b. Calculated as "with carbon" less "without carbon".
Source: ACIL Tasman, Estimated wholesale energy costs for 2013-14 retail tariffs – final report, May 2013.

3.4 Other Energy Costs

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

Relevant additional energy costs are considered below, including:

(a) the Queensland Gas Scheme;

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

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

(d) prudential requirements; and

(e) NEM participation fees and ancillary services charges.

The inclusion of a mechanism to address any new compulsory scheme that imposes material costs on retailers is considered in Chapter 5.

3.4.1 Queensland Gas Scheme

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

On 8 March 2013 the Queensland Government announced that, due to the introduction of the carbon tax by the Commonwealth Government, 2013 would be the final liable year for the Queensland Gas Scheme. As a result, to estimate the cost of complying with the Queensland Gas Scheme for the 2013-14 price determination period, the following information is required:

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

(b) the cost of obtaining GECs to meet that target.

The annual mandatory targets are prescribed under the Electricity Act. In 2013, a retailer is required to obtain GECs equivalent to 15% of its annual electricity load[22].

In past reviews, the Authority has highlighted its preference to use market prices to estimate costs where sufficiently robust data is available. In the early years of the Queensland Gas Scheme, market data was not sufficiently robust to use as a reliable basis for GEC costs. In those years, the Authority used the penalty price as a proxy for market outcomes. During this period, GECs were generally trading close to the penalty price.

In recent years, more market data has become available from the Australian Financial Markets Association (AFMA) and, for its 2012-13 pricing review, the Authority estimated Queensland Gas Scheme compliance costs based on market price information.

Submissions

In response to the Authority's consultation papers and the Draft Determination, submissions highlighted that, as the Queensland Gas Scheme would cease operation at the end of 2013, retailers would only incur costs for the first 6 months of the 2013-14 determination period. In addition, several retailers were critical of using current market data to estimate GEC costs, preferring instead for GEC costs to be based on the long term cost of compliance, suggesting that current market data did not reflect the cost to retailers of purchasing GECs through long term supply contracts between retailers and eligible generators.

In contrast, QCOSS supported estimating GEC costs using AFMA market data, arguing that this best reflected the actual costs faced by retailers. QCOSS also suggested that a shorter data series be used, to coincide with the wholesale energy cost hedging period. In response to the Authority's consultation papers Stanwell preferred the use of a shorter data series, suggesting a two-year data series be used on the basis that:

(a) GEC Scheme participants are not entering into long term contracts;

(b) the GEC price has fallen dramatically in recent years; and

(c) new entrant retailers had purchased sufficient certificates from the market.

In response to the Draft Determination, Stanwell highlighted the importance of the 2013 allowance accurately reflecting changes in the market price caused by the closure of the scheme.

The Authority's Position

The Authority considers that information on actual GEC contracts might be a preferable basis for estimating future costs but, as noted by ACIL in its draft report, this information is unavailable and market data is the only available source of information on GEC costs.

The Authority maintains its view that using a proxy measure, such as an approach based on the LRMC of gas-fired generation, to estimate GEC costs is inferior to a market-based approach on the basis that an LRMC approach is less transparent and more complicated.

[22] http://www.business.qld.gov.au/industry/energy/gas/queensland-gas-scheme.

Based on current market data and the requirement for retailers to obtain GECs for 15% of their electricity load for 2013 only, ACIL estimated the total cost of complying with the Queensland Gas Scheme for 2013-14 to be $0.25/MWh.

3.4.2 Enhanced 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% for each year from 2010 to 20% by 2020.

From 1 January 2011, the RET scheme changed into the Enhanced Renewable Energy Target (ERET) scheme. The changes split the scheme into two categories; a Small-scale Renewable Energy Scheme (SRES) and an Large-scale Renewable Energy Target (LRET).

The SRES covers small-scale technologies such as solar panels and solar hot water systems installed by households and small businesses. 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, which is 41,000 GWh by 2020.

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.

LRET Costs

For the 2012-13 pricing determination, the Authority used a market-based approach to estimate LRET costs. ACIL based its estimate of 2012 LRET costs on weekly market prices for LGCs published by AFMA and the latest Renewable Power Percentage (RPP) and annual LRET targets set by the Clean Energy Regulator (CER), formerly the Office of the Renewable Energy Regulator (ORER). For 2013, ACIL estimated total liable energy and used the latest published LRET target to arrive at a forecast RPP.

Approaches in Other Jurisdictions

In their most recent final price determinations, the ICRC (ACT) and the Office of the Tasmanian Economic Regulator (OTTER) (Tasmania) adopted market-based approaches to estimate the cost to retailers of complying with the LRET scheme. While OTTER estimated LRET costs based on its regulated retailer’s forward purchasing strategy, the ICRC estimated LGC costs based on spot market prices published by ICAP.

IPART (NSW) and ESCOSA (South Australia) based their cost estimates on the LRMC of renewable generation in their most recent final determinations. In its recent draft determination for 2013-16 prices, IPART proposed to continue with its previous approach of estimating the cost of LGCs based on the LRMC of meeting the overall LRET target. In its most recent final price determination, ESCOSA estimated the cost of LGCs based on the difference between the LRMC of a new entrant wind generator and a combined cycle gas turbine generator.

All four regulators applied the CER’s published and forecast RPPs in estimating LRET costs.

Submissions

As was the case last year, two different methods for calculating LRET compliance costs – a market-based approach and an approach based on the long-term costs of compliance – were proposed in submissions. AGL suggested that an approach based on the long-term costs of compliance would acknowledge that some retailers have invested in renewable generation. QCOSS preferred a market-based approach to estimating LRET compliance costs on the basis that this would more closely reflect the costs to retailers.

The Authority's Position

The Authority considered whether an LRMC-based approach should be used in previous pricing decisions, but determined that it was more appropriate to use actual market data than proxies such as the LRMC. Although ACIL noted that retailers acquire most of their LGCs through long-term contracts with wind farms or through direct wind farm ownership, the prices in these contracts are not publicly available.

While some retailers noted that there is a lack of liquidity in the market for LGCs, a low volume of trading does not necessarily mean market prices are unreliable. Following an examination of market prices over recent years, ACIL concluded that the market price has reacted as one would expect to prevailing market conditions.

As there were no new arguments in submissions to persuade the Authority to change its past approach to calculating the cost of LGCs, the Authority has again calculated LGC prices using market data. However, in recognition of the current lack of liquidity in the market, ACIL averaged LGC market prices published by AFMA over an extended period of 121 weeks for 2013 LGCs and 69 weeks for 2014 LGCs.

ACIL has used these averaged prices for LGCs, the published RPP of 10.65% for 2013 and its own estimate of the 2014 RPP of 9.11%, to arrive at a cost of complying with the LRET scheme of $4.15/MWh in 2013-14.

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

SRES Costs

For the 2012-13 Determination, the Authority estimated SRES compliance costs using the binding 2012 Small-scale Technology Percentage (STP) target for the first half of the pricing period and the non-binding 2013 target for the second half of the pricing period. The Authority calculated the cost of meeting these targets using the clearing house price of $40, after ACIL advised that, at that time, it would be difficult to estimate the proportion of STCs that were being traded outside the market. ACIL also expected any difference between market prices and the clearing house price to be short term and diminishing over time. However, the latest survey data from AFMA indicates that STCs are still trading at a 20% discount to the clearing house price.

Approaches in Other Jurisdictions

In their most recent final price determinations, IPART (NSW), ESCOSA (South Australia) and OTTER (Tasmania) all adopted a market-based approach to estimate SRES costs based on the CER's Clearing House price of $40 per STC and CER's binding and non-binding STPs for the relevant years.

However, the ICRC (in its June 2012 final report) and IPART (in its recent draft determination) estimated STC costs based on market prices and CER's binding and non-binding STPs for the relevant years. In its draft determination, IPART stated that, in contrast to its previous price determinations, it considered the market for STCs had matured and that there was now sufficient liquidity in the market to rely on traded price data. In addition, the Climate Change Authority recently made a draft recommendation that certificates only clear through the STC Clearing House when there is a deficit of STCs.

Submissions

Submissions in response to the Authority's consultation papers and Draft Determination were broadly in favour of continuing to use a market-based approach, based on the fixed Clearing House price and binding and non-binding STPs, determined by the CER.

QCOSS, Stanwell and the Clean Energy Council suggested that market prices for STCs should be used instead of the fixed Clearing House price given that there is an active market for STCs and the current market price is well below the Clearing House price. Stanwell and QCOSS were of the view that the information required to estimate STC costs using market data is available and suggested that the Authority base SRES compliance costs on the market value of STCs. QCOSS noted that the ICRC had utilised market prices in recent decisions.

AGL supported the Authority's proposal to use the published binding and non-binding STPs. Origin Energy and QEnergy had concerns with using the 2013 non-binding STP published by the CER, and were in favour of using a mechanism that allowed retailers to recoup material differences between previously forecast and actual STP targets in later tariff years. Origin Energy also suggested that the Authority use costs associated with the 2013 calendar year to estimate 2013-14 SRES costs. QEnergy suggested that an arbitrary uplift be applied to SRES compliance costs, on the assumption that the 2014 forecast target may be understated.

The Authority's Position

While the current market price for STCs may be below the fixed Clearing House price of $40 per STC, ACIL advised the Authority that there were difficulties with forecasting market prices of STCs over 2013-14. ACIL stated in its final report that since the announcement of the binding 2013 estimate, STC prices had risen sharply to around $37. ACIL stated that due to the effects of a reduction in the solar multiplier and feed-in tariff reform, the current oversupply of STCs would decrease, which is likely to result in market prices for STCs moving even closer to the Clearing House price.

On this basis ACIL recommended that the Authority continue to use the Clearing House price in calculating STC prices for 2013-14.

As suggested in submissions, ACIL considered a number of alternative information sources, such as data from energy brokers and certain industry associations, but concluded that the information provided by these sources was not readily available and would therefore reduce the transparency in the Authority's approach to calculating costs with no guaranteed improvement in forecasting accuracy.

The Authority acknowledges retailers' concern regarding using the CER's non-binding STP for 2014, but agrees with ACIL that the non-binding STP published by the CER on 15 March 2013 represents the most transparent and publicly available estimate for the STP for 2014. Concerns about material differences between the forecast and binding STP targets are addressed by the Authority's inclusion of a cost pass-through mechanism for 2013-14, as discussed in Chapter 5.

ACIL has used the Clearing House prices, the CER's binding STP of 19.70% for 2013 and the latest non-binding STP of 8.98% for 2014, to arrive at a cost of complying with the SRES scheme of $5.74/MWh in 2013-14.

ACIL has provided a detailed explanation of its calculation of SRES costs in its final report, along with information on STC prices and assumptions underpinning the STPs.

3.4.3 NEM Participation Fees and Ancillary Services Charges

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

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

Approaches in Other Jurisdictions

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

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

Submissions

Submissions generally supported the proposal by the Authority to continue using the approach to estimating NEM participation fees and ancillary services charges it had used in previous pricing decisions. However, Origin Energy stated that the Draft Determination had made no mention of other AEMO fees that retailers are required to pay, namely for FRC costs and the National Transmission Planner.

The Authority's Position

Given the general support from stakeholders for the Authority's approach to estimating ancillary services charges based on historical data, the Authority has continued with this approach for 2013-14. On this basis, ACIL has estimated that ancillary services charges will be $0.30/MWh in 2013-14.

Using AEMO's Draft Budget Fees, ACIL has estimated that total NEM fees will be $0.37/MWh for 2013-14 (inclusive of FRC fees and costs relating to the National Transmission Planner, National Smart Metering and the Electricity Consumer Advisory Panel).

3.4.4 Prudential Capital

Prudential capital costs relate to the financial guarantees a retailer must provide to AEMO and hedging providers as part of its hedging strategy.

Submissions

In response to the Authority's consultation papers, QEnergy suggested that, if the Authority adopted a market-based approach based solely on futures contracts, then it should also account for the additional bank guarantees that a retailer would have to purchase if it hedged using futures that it would not otherwise require if it hedged through other means such as PPAs or investing in generation.

AGL, Ergon Energy and Origin Energy supported QEnergy's suggestion, but suggested that the allowance be based on the costs faced by a new entrant retailer, as opposed to the distributor-based weighted average cost of capital (WACC) use by ACIL in the Draft Determination. Origin Energy also stated that the inclusion of prudential capital, while welcome, did not address its concerns regarding the treatment of PPAs and internal generation.

QCOSS was not in favour of the inclusion of costs associated with prudential capital on the basis that other regulators had not included separate allowances for these costs. QCOSS stated that the Authority must prove that the allowances are not already included elsewhere and requested that ACIL substantiate inputs to their estimates. Stanwell argued the allowance was unnecessary because incumbent retailers have entered into PPAs and invested in generation which would reduce prudential capital requirements.

The Authority's Position

The Authority considered this issue in its 2012-13 review in the context of retail operating costs and at that time considered that these were likely already accounted for in the retail operating cost estimate. However, following further consideration of the issue raised in submissions this year, the Authority is now of the view that these costs may not be included in the benchmarked retail operating costs and that it is appropriate to account for these prudential costs in the context of estimating the cost of energy.

ACIL is of the view that retailers that hedge through futures will face higher prudential capital requirements than retailers that enter into PPAs or invest in generation. On this basis, ACIL has included an allowance of \$0.585/MWh for prudential capital costs, made up of \$0.278/MWh for AEMO prudentials and \$0.307/MWh for hedge prudentials.

3.4.5 Summary of Other Energy Costs for 2013-14

Table 3.3 shows the proposed other energy costs for 2013-14 which will be applied uniformly across all tariffs.

Table 3.3: Other Energy Costs - All Tariffs - Excluding Losses

Cost Component	*2012-13* ($/MWh)	*2013-14* ($/MWh)	*Change* %
GEC	0.85	0.25	-70.6%
LRET	4.10	4.15	1.2%
SRES	6.38	5.74	-10.0%
NEM fees	0.40	0.37	-7.5%
Ancillary services	0.46	0.30	-34.8%
Prudential capital	-	0.58	-
Total	**12.18**	**11.38**	**-6.6%**

Note: Totals may not add due to rounding
Source: ACIL Tasman, Estimated wholesale energy costs for 2013-14 retail tariffs – final report, May 2013

3.5 Energy Losses

A retailer must purchase sufficient energy to supply its customers and allow for the transmission and distribution losses that will be incurred. In its 2012-13 Determination, the Authority applied transmission and distribution losses published by AEMO to all energy cost components.

Submissions in response to the Authority's consultation papers and Draft Determination generally supported the way in which loss factors had been estimated and applied in the 2012-13 price determination.

ACIL has used the most recent transmission loss factors and distribution loss factors available from the AEMO website at the time of preparing its final report. ACIL has used loss factors from the Energex distribution area for small customers and the Ergon Energy distribution area for large customers and streetlights. To estimate transmission losses, ACIL calculated a load-weighted average of all marginal loss factors in each distribution area. In determining distribution losses, ACIL applied loss factors that apply to the underlying network tariff classes.

In its final report, ACIL has modified the way in which it applies losses to energy costs to align its approach with AEMO's settlement process.

Table 3.4 shows the loss factors that have been applied to the different energy cost estimates in ACIL's final report.

Table 3.4: Energy Loss Factors for 2013-14

Settlement class	*Retail Tariff*	*Transmission and distribution loss factor*
Energex NSLP and unmetered supply	11, 12, 13, 20, 22, 41, 91	1.073
Energex Controlled Load 9000	31	1.073
Energex Controlled Load 9100	33	1.073
Ergon Energy NSLP- small, medium and large demand and streetlights	44, 45, 46, 71	1.135
Ergon Energy NSLP- high voltage, CAC[a] and ICC[b]	47, 48	1.088

a. Connection Asset Customer (generally consuming between 4GWh and 40GWh per annum).
b. Individually Calculated Customer (generally consuming over 40GWh per annum).
Source: ACIL Tasman, Estimated wholesale energy costs for 2013-14 retail tariffs – final report, May 2013

3.6 Total Energy Cost Allowances for 2013-14

Table 3.5 shows the total energy cost allowances for each settlement class and retail tariff for 2013-14.

Table 3.5: Total Energy Cost Allowances for 2013-14 by Settlement Class/Tariff

Settlement class	*Retail Tariff*	*Wholesale energy allowance (including carbon)*	*Other energy costs*	*Energy losses*	*Total energy allowance for 2013-14*		*Change from 2012-13*
		($/MWh)	*($/MWh)*	*(%)*	*($/MWh)*	*(c/kWh)*	*(%)*
Energex NSLP and unmetered supply[a]	11, 12, 13, 20, 22, 41, 91	69.43	11.39	1.073	86.71	8.671	9.2%
Energex Controlled Load 9000	31	47.06	11.39	1.073	62.71	6.271	8.0%
Energex Controlled Load 9100	33	57.89	11.39	1.073	74.33	7.433	12.7%
Ergon Energy NSLP – small, medium and large demand and streetlights	44, 45, 46, 71	64.08	11.39	1.135	85.65	8.565	9.7%
Ergon Energy NSLP- high voltage, CAC[b] and ICC[c]	47, 48	64.08	11.39	1.088	82.10	8.210	10.2%

a. In 2012-13, values for this settlement class didn't apply to Tariff 11 (as Tariff 11 was determined by the Minister) or Tariff 13 (as it is a new tariff for 2013-14).
b. Connection Asset Customer (generally consuming between 4GWh and 40GWh per annum).
c. Individually Calculated Customer (generally consuming over 40GWh per annum).
Source: ACIL Tasman, Estimated wholesale energy costs for 2013-14 retail tariffs – final report, May 2013.

4. RETAIL COSTS

The final cost component is retail costs which comprise:

(a) retail operating costs (ROC), which are the cost of services provided by a retailer to its customers; and

(b) the retail margin, which represents the reward to investors for the retailer's exposure to systematic risks associated with providing customer retail services.

Unlike last year, there are no specific requirements in the Delegation in relation to determining retail costs.

4.1 Retail Operating Costs

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

4.1.1 Approach to Estimating ROC

There are two generally accepted approaches to estimating ROC. A bottom-up approach, which requires detailed information on each cost component, and 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. Regulators in other jurisdictions tend to use a combination of a bottom-up analysis and benchmarking.

Approach for 2013-14 Determination

In its 2012-13 Determination, the Authority used a benchmarking approach, as it considered that undertaking a bottom-up exercise would not necessarily have produced results that were any more robust or defensible.

In submissions, retailers, consumer groups, Ergon Energy and the Queensland Government broadly supported a continuation of that approach. However, EnergyAustralia argued that, rather than solely relying on benchmarking, the approach should instead be used to complement a bottom-up approach. AGL, while broadly supporting a benchmarking approach, was also concerned that regulators use benchmarks without input from retailers.

However, as the Authority has previously explained, there are several problems with conducting a bottom-up assessment of retail costs.

Even if the Authority was able to obtain reliable cost information from retailers, determining the efficiency and reasonableness of those costs would be difficult. Other sources of information on the disaggregated costs of retailers are not available to inform the Authority's assessment because retailers have not provided the Authority with ROC information in the past and, in other jurisdictions, if retailers provide disaggregated cost information to the regulator, this tends to be on a confidential basis. Similarly, it is likely that any data the Authority required retailers to provide would also be confidential, which would prevent scrutiny of costs by other stakeholders. The process of obtaining information could be data intensive and data may be classified differently between retailers, making comparisons difficult.

While the Authority could assess cost estimates using a high level benchmarking analysis, a potential problem would arise if there was a large discrepancy between the results of the benchmarking analysis and retailers' proposed costs or even between retailers themselves. This would likely require the Authority to choose one approach (or cost estimate) over the others and there may be little basis for doing so. However, the Authority's benchmarking approach has benefited from the bottom-up analyses that have been undertaken by regulators in other jurisdictions (the most recent of which is by IPART).

EnergyAustralia suggested that many issues the Authority has highlighted with a bottom-up approach also apply to benchmarking, given the reliance placed on the bottom-up approach by other regulators. However, the Authority notes that regulators in other jurisdictions have experience over a number of years in assessing the reasonableness of retailers' costs. The Authority considers that it is appropriate to take account of this analysis in setting the appropriate level of ROC for Queensland retailers given that many retailers operate across jurisdictions.

While the Authority does recognise that benchmarking has its drawbacks, it does not consider that an alternative approach would necessarily produce results that are more robust or defensible.

The Authority's Position

For the reasons outlined above, the Authority has decided to continue using a benchmarking approach to determine the ROC allowance.

4.1.2 Implementing the Benchmarking Approach

In undertaking the benchmarking analysis, a key point to note is that the Authority must determine regulated retail electricity prices for small customers and large customers (those consuming more than 100 MWh per annum), whereas regulators in other jurisdictions are required to set prices for small customers only and these are to be charged by specific retailers. Therefore, the benchmarks from these jurisdictions are most relevant in providing information on the costs of supplying relatively small customers.

In its 2012-13 Determination, the Authority determined three separate ROC allowances for small, large and very large customers and it has done the same for this Determination. This approach was supported by the Government.

Establishing a Benchmark ROC Allowance for Small Customers

In the 2012-13 Determination, the small customer ROC allowance was determined by reference to the allowances recently determined by regulators in other NEM jurisdictions. As it was not possible to readily compare the costs attaching to CARC between jurisdictions, the Authority based its benchmarking solely on comparable ROC allowances and maintained the 2011-12 CARC allowance in real terms.

The Authority considered that the determinations by IPART and ESCOSA were more comparable with the Authority's task than the (higher) allowances determined by the ICRC and OTTER. The allowances determined by IPART and ESCOSA were based on the costs of large retailers that are likely to have achieved economies of scale and this was consistent with the Authority's representative retailer definition. While the allowances determined by ICRC and OTTER were higher than the Authority's 2011-12 allowance, the retailers in those jurisdictions supplied small customer bases and were unlikely to be operating at scale[23].

Based on this analysis, the Authority adopted an allowance of $86.29 (excluding CARC) for the 2012-13 Determination, which was consistent with the top of the range determined by IPART.

The Government suggested that the Authority should consider extending its benchmarking analysis to other industries that provide retail services. However, there is no necessary link between the costs of retailing electricity and retailing other services. Already, there is often disagreement from stakeholders about the appropriateness of benchmarking Queensland retailers against retailers from other states. Extending the coverage would most likely generate yet more debate. Regardless, undertaking such an exercise would require there to be publicly-available and comparable information which is unlikely to be the case. For these reasons, the Authority considers that limiting its benchmarking to the electricity sector continues to be appropriate.

For the Draft Determination, and in the absence of any new regulatory decisions or convincing arguments to pursue a different approach, the Authority proposed to base its estimate of ROC for 2013-14 on that adopted in 2012-13, suitably escalated to reflect inflation between years.

However, the Authority noted that it would take into account any new information revealed in IPART's forthcoming draft decision on electricity prices to apply from 1 July 2013 to 30 June 2016 (and any other new decisions that might come to light) in preparing its Final Determination.

IPART's 2013 Draft Decision

The Authority has reviewed IPART's draft decision[24] which included updated ROC allowances for small customers based on a level of detailed, bottom-up analysis not undertaken since 2009 (for IPART's previous pricing determination). IPART estimated CARC separately to the ROC allowance and this is discussed in further detail below.

IPART estimated ROC using a bottom-up approach based on cost information provided by retailers. It then benchmarked this estimate against regulatory decisions in other jurisdictions and retailers' publicly reported costs. This was consistent with the approach it adopted in its 2010 Determination.

Based on this analysis IPART estimated that the efficient level of ROC was in the range of $110 to $116 (in 2012-13 prices). After making an adjustment to remove the costs that retailers recover through a late payment fee ($3.80), IPART's draft decision was to set the ROC allowance at $110, which was consistent with the mid-point of its estimated range. IPART proposed to maintain the ROC in real terms over the determination period.

[23] ICRC, *Final Decision, Retail Prices for Non-contestable Electricity Customers 2010-2012*, June 2010, pp. 39-40; OTTER, *Investigation of Maximum Prices for Declared Retail Electricity Services on Mainland Tasmania, Draft Report*, August 2010, p. 71; and OTTER, *Investigation of Maximum Prices for Declared Retail Electricity Services on Mainland Tasmania, Final Report*, October 2010, p. 77.
[24] IPART, *Review of regulated retail prices for electricity, 2013 to 2016, Draft Report*, April 2013, Chapter 8.

IPART's proposed allowance is significantly higher than the allowance it adopted in its 2010 Determination. The main reasons that IPART gave for the increase were:

(a) ROC can now be more accurately estimated because the retailers are no longer integrated with distribution businesses;

(b) Higher network costs and the carbon tax have increased the risk of bad debt. Retailers now need higher working capital to allow customers to pay in arrears. Higher bills have also led to more complaints and higher credit, collection and call centre costs;

(c) More customers have installed solar panels which has resulted in retailers spending more time processing connection orders and quotes and dealing with customer queries; and

(d) The *Clean Energy Act 2011* has created additional administrative costs.

The Authority's Position

IPART's updated analysis suggests that the ROC allowance the Authority proposed in the Draft Determination is too low and would not reflect the efficient costs of providing retail services. While Stanwell considered that the Authority's proposed allowance was reasonable, some retailers argued that the 2012-13 ROC allowance was too low. For instance, AGL estimated that its ROC for 2011-12 (including CARC and an allowance for regulatory fees) was $140 per customer which was higher than the allowance of $134 per customer proposed in the Authority's Draft Determination.

AGL and EnergyAustralia suggested that ROC should be estimated on the basis of a smaller new entrant retailer in order to promote competition. However, the Authority considers that this would not reflect the efficient costs of supply and, more importantly, the Authority already makes a specific allowance for 'headroom' which is intended to sustain an appropriate level of competition in the Queensland market (see Chapter 5).

EnergyAustralia and AGL suggested that the benchmarking analysis needed to account for differences in costs between jurisdictions, such as credit costs and regulatory costs. However, no information was provided on the extent of the cost differences between Queensland and other jurisdictions and the Authority already includes an allowance for its regulatory fees (see below).

On balance, the Authority considers that it is appropriate to increase the ROC allowance to reflect IPART's proposed allowance of $110 per customer as it reflects the most up-to-date and relevant information on the efficient level of ROC, whereas the Authority's 2012-13 allowance was benchmarked against allowances based on analysis undertaken in 2009. The Authority also considers that it is appropriate to add back IPART's estimate of the costs associated with late payments ($3.80 per customer) because, unlike in NSW, retailers in Queensland cannot charge a separate late payment fee.

The total benchmark ROC allowance of $113.80 is in 2012-13 dollars and has been escalated to 2013-14 dollars as set out below. While the Authority's current view is that this allowance should be maintained for the remainder of the delegation period (subject to adjustments for inflation) the Authority will also consider any updated analysis that IPART undertakes for the purposes of its final determination.

Establishing Benchmark ROC Allowances for Large Customers

For the purposes of its 2012-13 Determination, the Authority found limited evidence upon which to determine an appropriate ROC allowance for large customers, as regulators in other jurisdictions only determine retail electricity prices for small customers. However, the Authority was able to draw on analysis conducted by Frontier Economics (Frontier) for the Western Australian Office of Energy in 2009[25] and ERA in 2012[26]. Frontier's analysis suggested that there was a significant difference in the costs of servicing larger customers which reflected more substantial marketing and account management costs, and the additional cost of pricing large customer loads.

While acknowledging that there was limited evidence upon which to determine the appropriate amount of ROC to allow for large customers, the Authority considered that it was reasonable to accept that retailers may have to incur higher costs to target larger customers as they are less numerous and hence low cost blanket marketing would not be appropriate. The Authority also noted that larger customers are likely to require more time and effort to analyse their energy needs and construct appropriate offers and that it seemed reasonable that the larger the customer the more time and effort may be required to maintain them and manage their accounts.

Therefore, the Authority was of the view that a higher ROC allowance was appropriate for large and very large customers. On the basis of Frontier's analysis, the Authority set a ROC allowance of $700 per large customer (those consuming between 100 MWh and 4 GWh per annum) and $2,000 per very large customer (those consuming more than 4 GWh per annum). No additional allowance was provided for CARC for large or very large customers because it was implicitly included in Frontier's ROC estimates.

The Authority's Position

While there is no new evidence upon which to determine the appropriate amount of ROC to allow for large customers, the Authority considers that differential allowances remain appropriate and it will base its assessment of these on its 2012-13 ROC allowances, suitably escalated to reflect inflation between years (see below).

4.1.3 CARC

While some consumers and consumer representative groups have argued that no allowance should be made for CARC, the Authority maintains its view from previous considerations of this issue that some level of cost associated with customer acquisition and retention is a real cost normally incurred by retailers participating in a competitive market. To not recognise a legitimately incurred cost may reduce the incentive for retailers to actively participate in the market.

While the Authority acknowledges the argument made by some consumers and consumer representative groups that small customers in Ergon Energy's area must pay notified prices that include an allowance for CARC even though there is no effective competition in their area, this is an unavoidable consequence of the UTP.

The Authority also disagrees with MSF Sugar that CARC should not be included in large customer retail tariffs because there is little or no competition available to these customers. Given that large customer retail tariffs are now more cost-reflective than they have been in the past, the Authority expects that retailers would have more incentive to make competitive offers to these customers and AGL has indicated that it has been active in doing so.

[25] Frontier Economics, *Electricity Retail Market Review – Electricity Tariffs: Final Recommendations Prepared for the Western Australian Office of Energy*, January 2009, pp. 68-69.
[26] Frontier Economics, *Retail Operating Costs – A Report Prepared for the Economic Regulation Authority of Western Australia*, February 2012.

In the Draft Determination, the Authority proposed to maintain its 2012-13 CARC allowance of $43.17 per customer and to maintain that allowance in real terms by escalating it by CPI.

EnergyAustralia suggested that the Authority should use a different approach to setting the CARC allowance, noting that retailers may need to spend more on marketing to be more competitive. However, EnergyAustralia did not set out what an alternative approach might be, nor did it suggest by how much CARC should increase.

As discussed above, IPART has recently released its draft decision on regulated retail electricity prices to apply from 1 July 2013 to 30 June 2016 which includes updated estimates of CARC[27].

IPART's proposed CARC allowance includes the 'direct' or 'upfront' sales and marketing costs associated with acquiring customers as well as the 'indirect' or 'ongoing' costs that retailers must incur to offer a reasonable discount to the regulated prices. However, the Authority considers that the latter is similar in purpose to its headroom allowance (see Chapter 5) and should not be allowed for in the CARC allowance.

In relation to estimating the 'direct' or 'upfront' sales and marketing costs associated with acquiring customers, IPART considered current estimates of these costs from a range of sources, including information provided by the major NSW retailers and information reported to the market by publicly listed retailers. IPART noted that these estimates varied widely and recognised that they will change through time as a result of the level of competition, the nature and position of a retailer in the market and sales and marketing channels used.

The Authority's 2012-13 CARC allowance ($43) is lower than IPART's estimate based on retailer information provided to IPART ($48) and around the mid-point of the range of estimates of publicly listed companies ($34 to $51). IPART did not estimate the direct costs of retention but acknowledged that they were likely to be significantly lower than the direct costs of acquisition.

While the Authority has previously expressed its view that its CARC allowance may be on the generous side, the cost estimates presented by IPART suggest that the Authority's current CARC allowance is set at a reasonable level.

The Authority's Position

Consistent with the Draft Determination, the Authority will base its allowance for CARC on the 2012-13 allowance of $43.17, suitably escalated to reflect inflation between years. The CARC allowance will only form part of the small customer ROC allowance because, as noted above, it is already included in the ROC allowances estimated for large customers.

4.1.4 Adjusting the Benchmark ROC Allowances

Accounting for Changes to Existing Costs

The Authority has considered whether it is necessary to make any adjustments to the benchmark ROC allowances to reflect changes to existing costs. However, it considers that many issues raised by retailers (for instance that the allowance should reflect an increase in debt costs) are likely to have been addressed by adopting IPART's updated ROC allowance.

While EnergyAustralia submitted that it was facing increased costs as a result of an increase in the number of customers with solar panels and that these customers are more expensive to

[27] IPART, *Review of regulated retail prices for electricity, 2013 to 2016*, *Draft Report*, April 2013, Chapter 9.

serve than customers without solar panels, IPART suggested that its ROC allowance had partly increased for this reason. While the Authority does not consider that these additional costs are a valid cost item (because the Authority is required to determine notified prices for the sale of electricity to customers[28], not the purchase of electricity from customers), it does not have sufficient information to adjust the IPART benchmark to exclude these costs.

Last year, the Authority decided that it was appropriate to escalate the benchmark allowances by the change in the CPI, having previously inflated costs by a mixture of CPI and the change in average weekly earnings. In coming to this decision, the Authority considered that, on balance, in the absence of any better alternative, escalating ROC by CPI was a reasonable approach. The Authority also noted that regulators in other jurisdictions routinely index costs by CPI in multi-year price paths.

The Authority is still not aware of an alternative index that might better reflect the manner in which ROC is likely to change. Therefore, the Authority has escalated each ROC allowance using the forecast change in the CPI of 2.5% for the 12 months to 30 June 2014. This was drawn from the Reserve Bank of Australia (RBA) Statement on Monetary Policy of May 2013[29], which is the same source the Authority used for its 2012-13 Determination.

The Authority's Position

The Authority has escalated each ROC allowance using the forecast change in the CPI of 2.5%.

Accounting for New Costs

The Authority is not aware of any new costs that need to be accounted for separately in 2013-14 and, other than the cost of providing prudential capital raised by QEnergy (which has been addressed in estimating the cost of energy rather than ROC), no issues were raised in submissions.

The Authority's Position

While the Authority has again included a separate additional allowance for regulatory fees (see below), it does not consider that there are any new costs that need to be separately accounted for in the ROC allowance.

Regulatory Fees

As it has done in the past, the Authority will include an allowance in ROC (for both small and large customers) to reflect the imposition of regulatory fees by the Authority.

The aggregate of fees to be paid to the Authority by electricity retailers in Queensland is calculated by the Authority based on its estimate of the annualised actual cost of performing its functions over a five-year period. The total cost to be paid by retailers in 2013-14 is estimated to be $2.639 million. However, adjustments to this estimate may be made during the period to ensure that fees are not significantly higher or lower than the Authority's actual costs.

This total cost is recovered from retailers according to their market share. Based on the most recently available data on customer numbers of 2,080,891 (as at 31 March 2013), this translates into a cost per customer of $1.27 for 2013-14.

[28] As set out in section 90(1)(a) of the *Electricity Act 1994*.
[29] This is the mid-point of the RBA's range of 2% to 3%.

The Authority's Position

For the purposes of the Final Determination, the Authority has included an allowance of $1.27 per customer based on its latest estimate of regulatory fees.

4.1.5 The Authority's Final Determination

In summary, the Authority has:

(a) set three different ROC allowances to reflect the costs of supplying customers of different sizes;

(b) set the small customer ROC allowance based on IPART's most recent estimate of ROC and the Authority's 2012-13 allowance for CARC;

(c) maintained the 2012-13 ROC allowance for large and very large customers;

(d) escalated the small, large and very large customer allowances by CPI (except for regulatory fees which are separately estimated) to reflect inflation between years;

(e) included a separate allowance for regulatory fees imposed by the Authority; and

(f) not included any new costs in 2013-14 that need to be separately accounted for.

Table 4.1: Final Determination - 2013-14 ROC ($ per customer)

	Final Determination 2012-13	*Final Determination 2013-14*
Residential customers and small customers consuming up to 100 MWh/yr:		
Benchmark ROC	86.29	116.65
+ CARC	43.17	44.25
+ Regulatory fees	1.21	1.27
Total ROC	**130.67**	**162.16**
Large customers (consuming between 100 MWh and 4 GWh/yr):		
Benchmark ROC (incl CARC)	700.00	717.50
+ Regulatory fees	1.21	1.27
Total ROC	**701.21**	**718.77**
Very large customers (consuming more than 4 GWh/yr):		
Benchmark ROC (incl CARC)	2000.00	2050.00
+ Regulatory fees	1.21	1.27
Total ROC	**2001.21**	**2,051.27**

Note: Totals may not add due to rounding.

4.1.6 Applying ROC to Retail Tariffs

A further issue to consider is how to allocate ROC to retail tariffs and whether this should be applied to the fixed charge, variable charge or some combination of both. In theory, cost-reflectivity is achieved when the costs of supply are applied to each retail tariff on the basis of the driver or cause of those costs. Such an approach should lead to more efficient use of electricity because customers would pay for the costs they cause an efficient retailer to incur. Therefore, as a general rule, the mix of fixed and variable components for each tariff should reflect the manner in which the underlying costs are incurred. Fixed costs and costs that vary with the number of customers served are best recovered as fixed charges and costs that vary with consumption are best recovered as variable charges.

In its 2012-13 Determination, the Authority allocated ROC to the fixed component of retail tariffs. AGL, EnergyAustralia and Origin Energy supported the continuation of this approach in 2013-14.

The Authority's Position

For 2012-13, the Authority relied on a range of evidence in deciding on the most appropriate approach for allocating ROC. To date, it has not uncovered any evidence to suggest that an alternative approach would be more cost-reflective, nor was any evidence to this effect provided in submissions. Therefore, the Authority has continued to apply ROC to the fixed component of retail tariffs.

Consistent with the approach adopted last year, the Authority considers that, to the extent possible, each customer should pay for ROC only once (regardless of the number of retail tariffs under which they may be supplied). Therefore, the fixed ROC allowance has been applied to all retail tariffs except:

(a) controlled load tariffs (Tariffs 31 and 33), because customers accessing these retail tariffs will also be supplied under one of the general supply residential tariffs (Tariffs 11, 12 or 13); and

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

Although this may not capture all circumstances where customers are accessing multiple tariffs, the continued rationalisation of tariffs that commenced in the 2012-13 Determination is likely to reduce the possibility of customers paying ROC more than once.

The Authority's Final Determination

For this Final Determination, the Authority has applied the relevant ROC allowance (for small, large and very large customers) to the fixed component of each retail tariff, as follows:

(a) the small customer ROC of $162.16 per customer will apply to all small customer retail tariffs (Tariffs 11, 12, 13, 20, 22 and 41);

(b) the large customer ROC of $718.77 per customer will apply to retail tariffs where consumption is generally between 100 MWh and 4 GWh per annum (Tariffs 44, 45, 46 and 47);

(c) the very large customer ROC of $2,051.27 per customer will apply to the retail tariff where consumption is generally greater than 4 GWh per annum (Tariff 48); and

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

Table 4.2 converts these allowances to daily charges that will be applied to the relevant retail tariffs for 2013-14.

Table 4.2: Final Determination - ROC Allowances for 2013-14 - Fixed Charge

Retail Tariff	*Final Determination 2012-13 (c/day)[a]*	*Final Determination 2013-14 (c/day)[a]*
11, 12, 13, 20, 22, 41	35.800[b]	44.397
44, 45, 46, 47	192.113	196.788
48	548.278	561.607

(a) Charged per metering point.
(b) In 2012-13, this didn't apply to Tariff 11 (as Tariff 11 was determined by the Minister) or Tariff 13 (as it is a new tariff for 2013-14).

4.2 Retail Margin

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

4.2.1 Approach to Estimating the Retail Margin

In previous BRCI decisions and the 2012-13 Determination, the Authority set the retail margin on an earnings-before-interest, tax, depreciation and amortisation (EBITDA) basis which meant that an allowance for depreciation and amortisation was implicitly included and the retail margin was calculated as a percentage of total costs.

There are generally two alternative approaches to estimating the retail margin:

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

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

In its 2012-13 Determination, the Authority adopted a benchmarking approach and assessed the appropriateness of the 5% retail margin used under the BRCI approach against retail margins adopted in other jurisdictions. The Authority adopted this approach because it was not convinced that a more extensive and detailed analysis, such as a bottom-up and/or expected returns approach, would deliver significant benefits over the benchmarking approach. There was also general support for benchmarking in submissions.

The Authority considered that IPART's 2010 decision was the most relevant regulatory decision at the time to benchmark against. The low retail margin adopted by OTTER was not considered relevant because it was determined for a retailer facing significantly lower energy price and volume risk than retailers in other NEM jurisdictions. The decisions of ESCOSA and the ICRC were heavily reliant on benchmarking and were therefore considered less relevant than the IPART decision, where a much more comprehensive analysis was undertaken.

Approach for 2013-14 Determination

Origin Energy and AGL broadly supported continuing to use a benchmarking approach to estimate the retail margin, but argued that the Authority needed to account for the higher risks of retailing in Queensland compared with New South Wales. While the Authority recognises that the risks of retailing may vary between jurisdictions as suggested by some retailers, it would be a highly subjective process to (a) comprehensively establish what those differences are; and (b) quantify the impact of those differences on the retail margin.

QCOSS also broadly supported the continued use of a benchmarking approach and suggested that any updated estimates should only be used by the Authority if they are applicable to Queensland.

Stanwell suggested that the Authority should supplement benchmarking based on a bottom-up analysis and EnergyAustralia suggested the Authority should undertake a bottom-up analysis to calculate the margin. However, the determination of an appropriate retail margin is an imprecise exercise and the Authority is not convinced that an extensive and detailed analysis is warranted. For instance, despite extensive analysis in both its 2010 final decision and 2013 draft decision, IPART still needed to exercise judgement to select an appropriate retail margin within relatively wide recommended ranges.

The Government queried whether the retail margin should apply to all cost components, given that network costs are passed directly through to retail prices and the recovery of these costs does not represent a material risk to retailers. While the Authority estimates the retail margin as a percentage of total costs, the alternative option would be to estimate it as a percentage of the energy and retail components only. In its most recent determination, ESCOSA calculated the retail margin as a percentage (10%) of 'controllable costs' (that is, including retail and energy costs but excluding network costs).

Given that the alternative option would simply result in a higher margin to be applied to fewer costs (than if it were applied to all cost components), the Authority considers that the choice between these two approaches would make little difference. However, it also considers that network costs are not necessarily a costless pass-through for retailers, given that retailers must pay for their network costs before they can be recouped from customers and there is a risk that some customers will not pay their bill, meaning that the retailer will not recoup all of its network costs. Origin Energy supported this view.

The Authority's Position

For the purposes of this Final Determination, the Authority has continued to apply a benchmarking approach to estimate the retail margin and has calculated the retail margin as a percentage of total costs.

4.2.2 Implementing the Benchmarking Approach

As noted above, for the 2012-13 Determination, the Authority relied particularly on IPART's 2010 decision on the retail margin. IPART's objective in determining the retail margin was to compensate the regulated retailers for the systematic risks they face and it engaged a consultant to provide advice on a feasible range for the margin using three alternative approaches – expected returns, benchmarking and bottom up. IPART then selected the mid-point of the range for each approach and applied an equal weighting to each. The resulting 5.4% margin it selected was consistent with the mid-point of the reasonable range recommended by its consultant.

Given the detailed analysis undertaken by IPART, the Authority considered that it was reasonable for the retail margin to be lifted to be the same as that adopted by IPART, but did not consider that there was any justification to raise it any higher. Therefore, the Authority increased the retail margin from its previous level of 5% to 5.4%. In the Draft Determination, the Authority noted that there had not been any new regulatory decisions since its 2012-13 Determination, nor any compelling evidence presented in submissions that suggested the retail margin should change from its current level. On this basis, the Authority proposed leaving the retail margin at the 2012-13 level but indicated that, in preparing the Final Determination, it would take into account any new evidence regarding the appropriate level of margin that might become available once IPART's latest analysis of retail margins was released.

IPART's 2013 Draft Decision

The Authority has reviewed IPART's draft decision[30] which included an updated retail margin. IPART engaged the same consultant it relied on for its 2010 decision to update its previous analysis, using the same three approaches used previously. The ranges of retail margins generated from these approaches for 2010-13 and those proposed for 2013-16 are presented in Table 4.3.

IPART's consultant selected the mid-point of the range for each approach and applied an equal weighting to each. The resulting 5.7% margin it recommended was consistent with the mid-point of the reasonable range. IPART accepted this recommendation.

Table 4.3: Range of Retail Margins from IPART's 2013 Draft Decision

Approach used	*Range for 2010-13*	*Range for 2013-16 (Proposed)*
Expected returns	3.5% - 4.7%	3.9% - 4.8%
Benchmarking	6.5% - 6.9%	6.3% - 6.6%
Bottom-up	4.6% - 6.3%	5.7% - 7.1%
Overall range	4.9% - 6.0%	5.3% - 6.2%
Selected margin	5.4%	5.7%

Source: IPART, Review of regulated retail prices for electricity, 2013 to 2016, Draft Report, April 2013, Chapter 7.

The Authority's Position

As noted above, the determination of an appropriate retail margin is an imprecise exercise. Some retailers argue that a higher retail margin is warranted because the risks of retailing in Queensland are greater than those in NSW due, for example, to the lack of a cost pass-through/catch-up mechanism and LRMC floor in the cost of energy estimate. However, MSF Sugar, QCOSS, Queensland Consumers' Association and CCIQ suggested that the current retail margin was too high and should be lowered. Similarly, Canegrowers suggested that increasing the margin from 5% to 5.4% reduced the competitive pressure in the sector and gave incentives for retailers to increase their costs and seek higher margins in future.

While the Authority has (again) opted not to include an LRMC floor in setting energy costs (see Chapter 3), it does include an allowance for headroom. The Authority's allowance for headroom is consistent with the level of headroom included by IPART in its energy and CARC allowances, as discussed in Chapter 5. The Authority has also included a cost pass-through mechanism for 2013-14, also discussed in Chapter 5. For these reasons the Authority considers that retailers face similar levels of risk in Queensland and NSW, and that it is therefore appropriate to adopt IPART's updated estimate of the retail margin of 5.7%.

[30] IPART, *Review of regulated retail prices for electricity, 2013 to 2016, Draft Report*, April 2013, Chapter 7.

The Authority's Final Determination

The Authority has set the retail margin for 2013-14 at 5.7% of total costs, inclusive of the margin.

4.2.3 Applying the Retail Margin to Retail Tariffs

For the 2012-13 Determination, the Authority applied the retail margin equally (on a percentage basis) to each component (fixed, variable and demand) of each retail tariff. This meant that all customers would pay the same margin as a percentage of their total bill but, in dollar terms, larger customers would pay more than smaller customers. The Authority considered that this approach was appropriate because the retail margin is calculated as a percentage of total costs and retailers generally supported continuing with this approach for the 2013-14 Determination.

While EnergyAustralia agreed with this approach, Canegrowers suggested that the margin should only be applied to variable charges, on the basis that retailers would not earn a margin on their fixed costs in a competitive market. However, the Authority disagrees with this view. As set out above, the purpose of the retail margin is to compensate investors for their capital investment and exposure to systematic risks and is expressed as a percentage of total costs. If the retail margin was only applied to fixed charges, retailers would not be fully compensated for bearing these risks and this could have a negative effect on competition.

A retail margin which is not sufficient to compensate investors for their capital investment and exposure to systematic risks will lead to under-investment by existing retailers, deter entry into the market by new retailers and stall the development of effective competition.

The Government queried whether the same retail margin should apply to all customer groups, while Ergon Energy and Sucrogen supported applying different margins to small and large customers. The Authority acknowledges that there may be justification for applying different margins to different customer groups, for instance on the basis of differences in risk, but it would be a highly subjective process and Ergon Energy did not suggest how the different margins could be estimated. The Authority does allocate different operating costs to tariffs for small, large and very large customers reflecting the differing costs to retailers of servicing these customer groups.

The Authority's Final Determination

The Authority has decided to continue to apply the retail margin equally (on a percentage basis) to each component of each retail tariff.

5. COMPETITION AND OTHER ISSUES

5.1 Competition Considerations

In accordance with section 90(5)(a) of the Electricity Act, the Delegation requires the Authority to have regard to the effect of its price determination on competition in the Queensland retail electricity market. In its submission, the Queensland Government noted that this requirement was consistent with its policy objective that customers, wherever possible, should have the opportunity to benefit from competition and efficiency in the marketplace.

As discussed in Chapter 1, unlike in some sectors of the industry (for example, electricity distribution and transmission) where barriers to entry such as high fixed costs and significant economies of scale tend to preclude the development of competition, there are no significant barriers to the development of competition in the retail electricity sector. This is evidenced in the Queensland retail electricity market where competition has developed considerably since it was introduced more than five years ago, although it is largely limited to SEQ as a result of the UTP.

While the Government has stated that it is not convinced that all small customers are adequately protected from the effects of moving to a fully deregulated market at this time, under the Australian Energy Market Agreement (AEMA), it has agreed to phase out retail price regulation if effective competition can be demonstrated[31].

In light of these factors, the Authority considers that part of its role in setting notified prices is to provide a transition to effective competition and eventual price deregulation, particularly in SEQ. The Authority also notes retailers' support for the removal of price regulation to further promote competition.

Notified prices may provide a level of protection for customers until the Government is satisfied that competition provides a sufficient constraint on prices such that price regulation is no longer required[32]. In the meantime, the Authority considers that notified prices should not act as a constraint on the development of effective competition. In particular, the Authority considers that notified prices should not act as a barrier to retailers entering the market and competing vigorously to acquire and retain customers. Notified prices should also encourage customers to exercise market choice and seek out the best deal in the competitive market. Greater customer engagement should further incentivise retailers to compete vigorously to make the best offers to attract and retain customers.

Regulating prices to maintain or promote competition is generally achieved by including an allowance for excess profit or 'headroom' in prices (whether implicit or explicit) above the estimated efficient costs of supply.

[31] So far, Victoria and South Australia have deregulated retail electricity prices.

[32] The AEMC is required to assess the competitiveness of competition in each jurisdiction for the purposes of recommending whether price regulation should be phased out. It is undertaking a review of the NSW market. A review of the Queensland market is scheduled to follow, although it is unclear whether it will proceed given that the Standing Council on Energy and Resources (SCER) is developing a new review approach (expected to be in place by the end of 2013) which will provide a more market-wide and ongoing review of the state of competition. See AEMC, *Review of Competition in the Retail Electricity and Natural Gas Markets in New South Wales, Issues Paper*, 13 December 2012, p. 5; and Standing Council on Energy and Resources (SCER), *Meeting Communiqué*, 14 December 2012, pp. 1-2.

5.1.1 2012-13 Determination on Headroom

In its 2012-13 Determination, the Authority included an explicit allowance for headroom, of 5% of the estimated efficient costs of supply, in order to sustain an actively competitive market. The Authority considered that failing to do so might see a substantial reduction in market activity and the range of offers available to customers.

The Authority disagrees with QCOSS, Queensland Consumers Association and CCIQ that the 5% allowance was provided without any supporting justification or apparent attempt to quantify what headroom might already be in notified prices. In arriving at its decision, the Authority first looked at evidence of the current level of headroom in tariffs, including:

(a) a breakdown of the costs of supplying customers on the most common 2011-12 retail tariffs relative to the notified price for that tariff; and

(b) information on discounts to the notified price for the main residential tariff (Tariff 11) offered by retailers.

The Authority estimated that, on average, the level of headroom was around 6% in Tariff 11, but much higher in most other common tariffs, ranging between 12% and 23%. Given that the available headroom in Tariff 11 appeared to have been sufficient to foster a healthy amount of competition in the residential market, the Authority considered that the same level of headroom was likely to be sufficient to support competition for non-residential customers.

5.1.2 Approaches in Other Jurisdictions

While an explicit allowance for headroom has not been included by regulators in setting regulated retail electricity prices in any other jurisdiction to date, both ESCOSA in South Australia and IPART in NSW have included it implicitly in their previous determinations. However, in their most recent draft determinations both regulators proposed to include headroom explicitly instead. This is contrary to the assertion of QCOSS and Queensland Consumers Association that regulators in other jurisdictions have rejected arguments to include headroom.

South Australia and NSW

In their most recent final price determinations, IPART[33] and ESCOSA[34] both noted that certain aspects of the way they calculated regulated prices meant that new entrant retailers could face lower costs. Both regulators examined the state of competition in their respective markets and found that the regulated price was not a major barrier to entry.

More recently, in undertaking a ‘special circumstances’ review of the wholesale electricity cost allowance in 2012, ESCOSA made a draft determination to include an explicit allowance for headroom, rather than include it implicitly as it had done before[35]. However, that draft determination was not implemented as the South Australian Government announced that it would deregulate retail electricity prices from 1 February 2013.

IPART is undertaking its next review of retail electricity prices to take effect from 1 July 2013 and is also proposing to include an explicit allowance for headroom. In its draft

[33] IPART, *Review of Regulated Retail Tariffs and Charges for Electricity 2010-2013, Final Report*, March 2010.
[34] ESCOSA, *2010 Review of Retail Electricity Standing Contract Price Path, Final Report*, December 2010.
[35] ESCOSA, *2011-2014 Electricity Standing Contract Price Determination – Wholesale Electricity Cost Investigation, Determination of Special Circumstances Statement of Reasons and Draft Standing Contract (Further Variation) Price Determination*, October 2012, pp. 6-7.

determination, IPART[36] stated that one of its objectives was to support the long-term interests of consumers by facilitating increased competition in the market and enabling the removal of price regulation. To do this, IPART considered that regulated prices needed to be set high enough to incentivise retailers to enter the market and compete for customers and for customers to seek out better offers in the competitive market.

It is estimated that IPART has included an allowance for headroom of around 6% above the estimated efficient costs of supply in its draft determination. This reflects 75% of the 'indirect' or 'ongoing' costs that retailers must incur to offer a discount of 8% off the usage component of regulated prices.[37] IPART also proposes to include an allowance for 75% of the 'direct' or 'upfront' costs of acquiring customers which reflects the one-off sales and marketing costs of acquiring customers.[38] IPART decided to include less than 100% of the 'direct' and 'indirect' costs noting that it was reasonable to expect that retailers would earn reduced margins for some customers when entering a market or expanding market share. IPART proposed to recover these costs partly through the energy cost allowance (through the inclusion of LRMC in the calculation) and partly through the CARC allowance.

ACT and Tasmania

In contrast, in its 2012-14 price determination for the ACT[39], the ICRC set the regulated price based on the actual costs incurred by the sole incumbent retailer, on the basis that it was not convinced that the long-term benefits of setting higher prices would outweigh the short-term costs.

The concept of headroom to facilitate competition is not relevant in Tasmania because regulated retail prices are only determined for customers that are not contestable[40].

5.1.3 Should there be an Allowance for Headroom in the 2013-14 Determination?

QCOSS and Queensland Consumers Association argued that the inclusion of headroom was a departure from existing economically-sound principles on which regulated pricing of electricity and other products and services is based. AGL and Simply Energy suggested that regulating firms in markets where competition exists performs a different role to regulating firms in monopoly markets where competition is not expected to sufficiently constrain prices, meaning that regulation is required to perform this role, albeit imperfectly.

Several customers and customer representative groups argued that there was no justification for including an allowance for headroom, because it increases prices for little or no benefit to customers. For instance, QCOSS and Queensland Consumers' Association argued that retailers should be attracted to the market because they can operate more efficiently and innovatively and provide better customer service than incumbent retailers, not because regulated prices are artificially high. They also argued that some customers will continue to incur higher prices because they either have no option to take up a market contract or do not understand the options available to them. Canegrowers suggested that the Authority should determine prices that would be comparable to those that would be determined in a competitive market to incentivise retailers to reduce their costs.

As a general principle, the Authority considers that competition will do a better job at revealing efficient costs than regulation. As pointed out by the AEMC[41], regulation will

[36] IPART, *Review of regulated retail prices for electricity, 2013 to 2016, Draft Report*, April 2013, p. 22
[37] *Ibid.*, pp. 94-106.
[38] The Authority includes an allowance for sales and marketing costs in its ROC allowance (see Chapter 4).
[39] ICRC, *Retail Prices for Franchise Electricity Customers 2012-14, Final Report*, June 2012.
[40] OTTER, *Investigation of Maximum Prices for Declared Retail Electrical Services on Mainland Tasmania, Final Report*, October 2010.

almost always be an imperfect substitute for competition because regulators have imperfect information upon which to determine efficient prices and regulated prices are not as responsive to changes in costs as competitively determined prices.

However, as competition is still largely price driven, retailers must be able to offer some discount to the notified price in order to attract customers away from notified prices and build market share. The level of notified prices should not act as a barrier to the entry and expansion of smaller retailers in the market and they should (over time) develop more efficient processes and provide an effective constraint on the dominance of the incumbent retailers to the long-term benefit of customers.

While CCIQ considered that headroom provides a disincentive for retailers to be more efficient and innovative, the Authority considers that setting notified prices somewhat higher than the Authority's estimate of the efficient cost of supply will attract retailers to enter the market and, as they compete for market share, market prices will be driven down. The more active the competition, the closer retailers will reduce prices to their individual, efficient costs of supply. While regulated prices will be unaffected in this process, customers should be able to access lower priced market offers from competing retailers. With time, customers should also be able to benefit from improved service quality and, as argued by Meridian Energy, more innovative product offerings.

QCOSS expressed concern that customers may not be able to obtain market contracts with comparable terms and conditions to the standard retail contract and that applying a headroom 'premium' for customers to access the standard contract terms and conditions was not justifiable. However, customers must assess market offers by considering both the price and non-price inducements and the accompanying terms and conditions of the contract. Some customers may prefer to obtain supply under the standard contract terms and conditions and pay the notified price and this option is available to them.

QCOSS and Queensland Consumers' Association also argued that the Authority has gone outside the remit of the Delegation by including headroom because this means that it has not based its determination on an N+R methodology. The Authority considers that the N+R framework is intact and, in applying this framework, it is not precluded from including an additional allowance for headroom to satisfy the requirements of the Electricity Act and Delegation that it must consider the effect of its determination on competition in the Queensland retail electricity market.

Competition Outside SEQ

Residential and Small Customers

It is unlikely that any reasonable level of headroom allowed in the Energex network area would be sufficient to encourage retailers to offer market contracts to small customers in the Ergon Energy network area. As a result, and as pointed out by Ergon Energy, customers and customer representative groups, small customers in regional Queensland will have to pay the notified price, inclusive of any allowance for headroom.

Nevertheless, as notified prices for small customers are based on the costs of supply in the Energex network area, they are still likely to be lower than the actual costs of supplying this group of customers, meaning that the inclusion of headroom will have the effect of moving prices closer to cost-reflective levels. Headroom does not deliver additional profit to Ergon Energy as suggested by Cotton Australia. Ergon Energy receives a significant subsidy from

[41] AEMC, *Review of the effectiveness of competition in the electricity retail market in the ACT, Stage 2 Final Report*, 3 March 2011, p. 8.

the Queensland Government (estimated at around $620 million in 2012-13)[42] because the revenue it receives from customers paying notified prices is not sufficient to cover its costs of supply.

However, as pointed out in Chapter 1, the disparity between the lower market prices available to the majority of customers in SEQ and the higher notified prices customers elsewhere must pay, may be undermining the intent of the UTP which may need to be reviewed as progress is made towards deregulation in SEQ. QCOSS and Cotton Australia argued that the Authority is further undermining the intent of the UTP by including headroom. However, the Authority considers that including a reasonable level of headroom strikes an appropriate balance between promoting competition in SEQ, while recognising that customers outside of SEQ have limited or no access to competition.

Large Non-residential Customers

As discussed in Chapter 2, the Authority has set notified prices for large non-residential customers based on Ergon Energy's network charges because large non-residential customers in Energex's network area no longer have access to notified prices. However, Sucrogen and MSF Sugar argued that headroom should also not be included in large customer tariffs because there is little or no competition for large customers in the Ergon Energy network area.

However, the Authority considers that it is appropriate to include headroom in these tariffs to provide some incentive for retailers to make competitive market offers to large customers and given that large customer tariffs are now more cost-reflective than they have been in the past. As set out in Chapter 2, AGL indicated that it had been active in providing competitive market offers to large customers in Ergon Energy's network area since the creation of cost-reflective tariffs.

The Authority's Position

The Authority has decided to continue to include an allowance for headroom, above its estimate of the efficient costs of supply, to ensure competition is maintained in SEQ for small customers and to promote competition for large customers outside of SEQ.

While the Authority notes that including an explicit allowance for headroom in notified prices provides a "free kick" to those retailers with large numbers of non-market customers, those customers able to access a market contract can avoid this additional cost.

5.1.4 How Much Headroom?

In submissions, retailers generally argued that competition in Queensland was negatively affected by the 2012-13 Determination because notified prices and, in particular, the energy cost component, were set too low. ERAA and ESAA argued that competition has been declining since the release of the Authority's proposed methodology for the 2012-13 Determination, in November 2011. EnergyAustralia also suggested that low notified prices are contributing to a decline in competition, but recognised that large price increases proposed in the Draft Determination may also negatively impact competition by increasing bad debt levels.

In determining the appropriate level of headroom, the Authority has attempted to assess the impact of the 2012-13 Determination on competition in SEQ, but the task was hindered by

[42] Queensland Government, *State Budget 2012-13: Budget Strategy and Outlook, Budget Paper No. 2*, 2012, Appendix B.

the fact that the Government decided to freeze regulated prices for the main residential tariff (Tariff 11) for 2012-13, subject to the inclusion of costs associated with the carbon tax.

While the Authority did not determine Tariff 11 in 2012-13, the network tariff underpinning Tariff 11 was lowered to compensate retailers for the effects of the tariff freeze relative to the cost-reflective tariff that the Authority would otherwise have determined. However, some retailers, the ERAA and ESAA argued that the Government's decision to freeze Tariff 11 increased uncertainty and the risk of retailing in Queensland. These views have also been raised by retailers in a recent survey conducted for the AEMC as part of its current review of competition in retail energy markets in NSW:[43]

> *Based on the view of a number of respondents, retail price regulation is seen as one part of a package of regulatory matters that has created greater uncertainty and risk in the electricity market. This uncertainty and risk is heightened in light of the Queensland Government imposition of a freeze on electricity prices in Queensland and the proposed (but now halted) reopening of the price determination to review wholesale prices in South Australia.*

It has not been possible to isolate the impact of the Authority's decision on headroom from the impact of the Government's tariff freeze, making it very difficult to draw any meaningful conclusions about the effects of each of these decisions on the state of competition.

Current State of Competition

In considering the current state of competition in Queensland, the Authority has considered the following factors:

(a) switching rates;

(b) the number of active retailers and degree of market concentration;

(c) available market offers; and

(d) customer participation and engagement.

Switching Rates

Retailers generally argued that switching rates provide the most useful indictor of the level of competition in a market and that the declining switching rate in Queensland in recent years reflects a decrease in marketing activity by retailers. Click Energy suggested that a reduction in the switching rate was a key first indicator that competition was declining, with other indicators taking longer to reveal whether there is a problem.

Retailers noted that switching rates in Queensland are much lower than in other jurisdictions and have been declining in recent years. However, the Authority pointed out that the Queensland switching rate is significantly impacted by the inclusion of customers in the Ergon Energy network area where it is acknowledged that competition is extremely limited. For instance, while the Queensland switching rate was 10% (annualised) in April 2013, if Ergon Energy customers were removed from the calculation, the switching rate increases to approximately 15%. This compares to 20% in NSW, 19% in South Australia and 28% in Victoria[44].

[43] Sapere Research Group, *Review of Competition in the Retail Electricity and Natural Gas Markets in New South Wales – Report of Interviews with Energy Retailers, Prepared for the Australian Energy Market Commission*, February 2013, p. 36.
[44] AEMO, *National Electricity Market, Monthly Retail Transfer Statistics*, April 2013.

While the SEQ switching rate is lower than other Australian jurisdictions, in comparison to international competitive retail energy markets, the level of customer switching activity in Australian jurisdictions is particularly high. In 2011, Victoria had the highest switching rate in the world, South Australia was third, Queensland was fifth and NSW was tenth[45]. At current switching rates, SEQ would still be considered a very active market[46] by international standards.

The Authority considers that switching rates are one indicator of the competitiveness of a market, but are not the only indicator, nor necessarily the best. While acknowledging that the switching rate in Queensland has been generally decreasing in the past few years, there are a number of reasons why switching rates may be either high or low at any point in time.

As many retailers have suggested, a low or falling switching rate may be the result of retailers reducing their marketing activity because the level of headroom in notified prices is too low. Australian Power and Gas (APG) has publicly stated that it has not been actively marketing in Queensland since July 2012 due to "adverse pricing regulation imposed by [the Queensland] government."[47] QEnergy has also stated that it is not actively retailing in Queensland, while Alinta Energy indicated that it was not viable for it to enter the small customer market. QEnergy and Alinta Energy attributed their decisions to notified prices being too low. The ERAA advised that its discussions with retailers suggested a clear trend to invest in other states, as a result of the Authority's 2012-13 Determination and the Government's decision to freeze Tariff 11.

However, there may be several reasons why retailers choose to participate more actively in some markets than others at any point in time. For instance, markets that do not have price regulation (such as Victoria) are likely to be more attractive to retailers than those that do and the high switching rate in Victoria relative to other states, along with other positive competition indicators in that state[48] (see below), appears to support this. Retailers have also reported that competition has increased in NSW since the privatisation of the three Government-owned retailers in March 2011[49]. ERAA and ESAA also made this point in their joint submission.

A low or falling switching rate may also suggest that retailers have changed their marketing strategy as the market has matured, although the Authority recognises that FRC was introduced earlier in other states than in Queensland. While retailers do appear to be changing their marketing strategies, it is likely that the full effect on switching rates is yet to be seen. For instance, while door-to-door marketing has been much more widely used in electricity markets than other markets[50], AGL and Energy Australia both recently announced that, due to customer dissatisfaction, they have stopped door-to-door selling and will focus on alternative sales channels[51]. APG has stated that customer retention is an important focus

[45] VaasaETT, *World Energy Retail Market Rankings, 2012*, June 2012.
[46] VaasaETT, *World Energy Retail Market Rankings, 2012*, June 2012, p. 10.
[47] Australian Power & Gas, *Investor Update*, 11 March 2013, p. 7
[48] Australian Energy Regulator, *State of the Energy Market 2012*, 20 December 2012, pp. 118-126.
[49] Sapere Research Group, *Review of Competition in the Retail Electricity and Natural Gas Markets in New South Wales – Report of Interviews with Energy Retailers, Prepared for the Australian Energy Market Commission*, February 2013, p. 14.
[50] Approximately one million new energy contracts were sold as a result of door-to-door marketing in 2011, representing around 76% of total door-to-door sales. Frost and Sullivan, *Research into the door-to-door sales industry in Australia, Report for the ACCC,* August 2012, p. 8.
[51] EnergyAustralia Media Release, *Knock Knock...Who's there? Not EnergyAustralia*, 25 February 2013; and AGL Media Release, AGL withdraws from unsolicited door-to-door *sales*, 26 February 2013.

and that it is targeting existing high value customers as a retention strategy and building its online presence to "lower costs and enhance [the] customer experience[52]."

A low switching rate may also indicate that customers are satisfied with their current retailer and have no reason to change. This would suggest that competition is effectively constraining retailer behaviour to the benefit of consumers.

A high or increasing switching rate may be the result of retailers increasing their marketing effort to increase their market share because regulated prices are set much higher than costs or because some markets are more attractive than others for other reasons, such as those outlined above. However it could also signal greater consumer engagement and participation in the market. For instance, an increase in switching rates in New Zealand in 2011 (which placed it as the second most active market in the world after Victoria) was largely attributed to the success of a marketing campaign which aimed to increase competition by creating more informed and active electricity customers and increase their propensity to switch[53].

Nevertheless, high switching rates do not necessarily mean that customers are obtaining the best offer available in the market or even that they are better off than with their current retailer and could instead reflect high pressure sales tactics. It is not necessary for a customer to switch retailers to benefit from competition between retailers. If a customer can credibly threaten to switch retailers, this can provide an effective constraint against the exercise of market power by dominant retailers.

As noted by MSF Sugar, a market is operating effectively when customers receive competitive prices and services and switching rates will not always provide a good indication of this.

Number of Active Retailers and Market Concentration

The number of active electricity retailers and the relative size of their respective customer bases also provide an indication of the competitiveness of the electricity market. The greater the number of electricity retailers and smaller the market share of an individual or small group of electricity retailers, the less likely it is that an individual or small group of retailers can use their market power to raise prices. Furthermore, if retailers are entering the market, this suggests that the market is attractive to new entrants and that barriers to entry are relatively low.

There are 15 retailers supplying small customers in Queensland, including at least two retailers that have begun supplying customers since the Authority's 2012-13 Determination was released[54]. This appears contrary to the claims by ERAA and ESAA that new entrant investment is low and has declined since the 2012-13 Determination.

Origin Energy suggested that retailers are diverting resources to other states because notified prices in Queensland are too low, but that those with significant capital invested in Queensland will continue to participate in the market for longer. However, it is not possible for the Authority to verify such claims.

[52] Australian Power & Gas, *Investor Update*, 11 March 2013, p. 15.

[53] An early review of the campaign suggested that, in addition to increasing switching rates, it had improved customer awareness and incentivised retailers to offer bigger discounts. See Electricity Authority, *What's My Number – A changing landscape for New Zealand electricity consumers*, April 2012, available from: www.ea.govt.nz; and VaasaETT, *World Energy Retail Market Rankings, 2012*, June 2012, p. 2, p. 20.

[54] While 26 retailers hold a retail license, not all licensed retailers are making offers to customers or supplying customers, while some retailers are only supplying large customers.

ERAA, ESAA, Origin Energy and EnergyAustralia suggested that the Authority should review the data underpinning the switching rate to gain an understanding of which retailers' customers are switching to and whether the market is becoming more concentrated. Origin Energy presented graphs showing that its customer losses in Queensland have dropped by around 17% over the six months to November 2012 compared with same period last year and that its losses are largely to three other retailers. EnergyAustralia made a similar general observation.

Based on quarterly information reports provided by the retailers, the Authority has considered changes in the concentration of the market in the last year as reflected by the market shares of incumbent (or first tier retailers) relative to the market share of second tier retailers. The data indicate that the market share of second tier retailers was around 10.5% from September 2011 to December 2012 and increased to around 11% in the March quarter 2013. As suggested by EnergyAustralia, the Authority also reviewed the switching data attributable to the first tier retailers[55] but it does not appear to show that first tier retailers are gaining a greater proportion of customers from, or losing a smaller proportion of customers to, second tier retailers. The Authority does not consider that the evidence available to it suggests that the market has or is becoming more concentrated as retailers have suggested.

As noted by Origin Energy, the Queensland electricity market does appear to be more concentrated than some other Australian markets, although the SEQ market is much less concentrated and compares much more favourably. Smaller retailers have been more successful at building market share in Victoria (supplying 28% of the market) and South Australia (supplying 17% of the market) [56]but less successful in NSW (supplying 6% of the market)[57]. This compares to Queensland where smaller retailers supply approximately 11% of the Queensland market, but 16% of the SEQ market[58].

Market Offers

As explained by the AEMC[59], competition between retailers to secure customers for relatively homogenous products, such as electricity, tends to be price-based. Therefore, the extent and level of discounting by retailers can provide an indication of the extent of competition in a market.

While the Authority does not have access to information on market offers available to business customers, there are 63 supply offers available to residential customers consisting of offers for both 'standard' electricity supply and 'green' electricity supply. These market offers provide customers (almost exclusively in SEQ) with a range of contractual terms and conditions combined with other incentives[60].

Of the 63 supply offers available, 28 offer prices lower than the Tariff 11 notified price. The maximum generally-available discount is 13% (provided by one second tier retailer) followed by 11% (provided by two second tier retailers). These discounts are higher than the maximum discount of 10% in 2011-12[61]. While some retailers (including AGL and Origin Energy) advised that they have been reducing their marketing activity in Queensland because

[55] Confidential switching data obtained from AEMO from the December 2011 quarter to the March 2013 quarter.
[56] Australian Energy Regulator, *State of the Energy Market 2012*, 20 December 2012, p. 118.
[57] IPART, *Customer Service Performance of Electricity Retail Suppliers: 1 July 2007 – 30 June 2012*, December 2012, p. 5, p. 29.
[58] As at 31 March 2013.
[59] AEMC, *Issues Paper - Review of Competition in the Retail Electricity and Natural Gas Markets in New South Wales,* 13 December 2012, p. 34.
[60] As at 30 April 2013.
[61] As at 30 April 2013. Where the discount is applied to the usage charge only and/or rebates are offered, the total discount is calculated assuming typical annual consumption of 4,250 kWh.

notified prices are too low, they continue to offer discounts to new customers. Origin Energy argued that it is continuing to offer discounts to build market share and defend its investment, but claimed that its market offers (along with the market offers of AGL and EnergyAustralia) have reduced since the 2012-13 Determination (from around 10 to 13% in May 2012 to 7 to 9% in March 2013). However, the Authority notes that larger discounts are available from smaller retailers.

EnergyAustralia noted that the maximum discounts available indicate a desire for retailers to compete but suggests that they may only be offered to retain existing customers. While the maximum discounts presented above are available to new customers, the Authority is also well aware that (at least) Origin Energy makes substantially higher discount offers to customers under threat of moving to a new retailer. These discounts are not advertised in the marketplace. While Origin Energy agreed that it does make non-public offers to a small specific segment of its customers, it argued that the discounts are not as high as they were in the past.

ERAA and ESAA also claimed that, since 2010, discounting has been led by only a few retailers with some new entrants being forced to offer rates substantially above the regulated rate. However, the Authority is not aware of any evidence to support this statement and notes that seven second tier retailers are offering discounts to the notified price on the Authority's price comparator and no retailers are making offers above the notified price, except where these are for 'green' electricity supply which presumably incurs additional costs for retailers[62].

QEnergy presented analysis to suggest that prices in Queensland are low relative to other jurisdictions and only exceed prices in the ACT where competition is non-existent. However, the absolute level of prices does not provide a good indicator of the competitiveness of a market, as the underlying costs of supply will vary between jurisdictions.

Origin Energy argued that the level of discounting in Queensland is lower than in other states. While it is not possible to assess discounts available in Victoria and South Australia given that these markets no longer have price regulation, the maximum discounts available to regulated retail prices in NSW are around 13% to 15% (depending on the distribution area), which are similar to, or slightly higher than, the maximum discount of 13% available in Queensland[63].

Customer Participation and Engagement

Well-informed customers that actively participate in the competitive market put pressure on retailers to price competitively and provide products and services that meet their needs[64]. A lack of customer engagement can lead to dominant retailers charging higher prices than other retailers without losing significant market share.

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[62] As at 30 April 2013.
[63] Discounts accessed from IPART's "My Energy Offers" website: www.myenergyoffers.nsw.gov.au on 30 April 2013, assuming typical annual consumption of 4,250 kWh per year.
[64] AEMC, *Issues Paper - Review of Competition in the Retail Electricity and Natural Gas Markets in New South Wales*, 13 December 2012, p. 30.

A lack of customer engagement is a recognised issue in retail electricity markets, even in those markets that do not have price regulation[65]. Customers may not actively engage in the retail electricity market for a number of reasons, including:

(a) they are unaware that they can switch retailers;

(b) they face barriers to switching retailers, such as contract termination fees;

(c) they find it difficult to access and compare offers between retailers;

(d) they do not consider that the time and effort needed to obtain and compare retailers' offers will be worthwhile; or

(e) they perceive that they have little control over electricity prices because they are regulated.

While the Authority considers that a lack of customer engagement in the retail electricity market may indicate that competition is not as effective as it could be, higher electricity prices in recent times may provide some impetus for customers to become more proactive in securing a better deal.

The Authority also notes that the percentage of customers on market contracts continues to increase, which suggests that retailers are offering sufficient inducements to encourage customers to move from a standard contract to a market contract. As at 31 March 2013, 46.1% of Queensland electricity customers were supplied under a market contract, compared to 45.6% as at 31 December 2012[66].

This increase was due to growth in the number of both small and large customers on market contracts. Over this period, the percentage of small customers on market contracts increased from 45.4% to 45.8%, while the percentage of large customers on market contracts increased from 72.2% to 77.8%.

The Authority's Position

Some retailers argued that headroom should be set at a minimum of 5%, while others considered that it should be higher. AGL argued that headroom should be higher for small business customers than residential customers, but did not explain why. While retailers considered that competition was declining in Queensland, they generally suggested that this was due to the cost of energy allowance being too low. Conversely, Stanwell, customers and customer groups argued that the level of headroom should be reduced or eliminated because it is of little or no benefit to consumers.

On several measures, the level of competition appears to have been maintained or improved following the Authority's 2012-13 Determination. For instance, there has been an increase in the number of active retailers, bigger discounts to the notified price, stable or slightly improving market shares of second tier retailers and an increase in the proportion of customers on market contracts. On the other hand, the Authority is concerned that declining switching rates and indications from some retailers that they are no longer actively marketing in Queensland may indicate that competition has slowed. The Authority also notes the point

[65] See, for instance, Consumer Utilities Advocacy Centre, *Improving energy market competition through consumer participation*, December 2011, available from: www.cuac.org.au; Ofgem, *What can behavioural economics say about GB energy consumers?* 21 March 2011, available from: www.ofgem.gov.uk; Electricity Authority, *What's My Number – A changing landscape for New Zealand electricity consumers*, April 2012, available from: www.ea.govt.nz.

[66] See: http://www.qca.org.au/electricity-retail/InfoRep/CustomerStats.php.

made by Click Energy that there may have been an insufficient passage of time for any decline in competition to be fully revealed in the other competition indicators.

Nevertheless, the Authority does not consider that there is sufficient evidence to suggest that competition is declining in SEQ at this time. In any event, it would be difficult to determine whether any slowing was driven by the Authority's 2012-13 Price Determination or the Government's decision to freeze Tariff 11.

While some retailers argued that setting prices too low will be detrimental to the development of competition, they also argued that setting prices too high will simply result in increased competitive tension between retailers to attract customers. The Authority remains of the view that including some level of headroom in notified prices is necessary to support competition. However, in deciding on the appropriate level of headroom, the Authority must balance the long-term benefits to customers of sustaining an actively competitive market with the interests of those customers who may not have access to, or choose not to take up, alternative market offers.

The Authority is not convinced that increasing headroom from its current level will necessarily flow through to customers in the form of higher discounts, better service quality and/or more innovative product offerings. This is (in part) because customers that remain on notified prices will not receive these benefits, but also reflects the Authority's concern that a lack of customer engagement and participation in the market may be a significant issue resulting in some customers not obtaining the benefits of competition that they should. The Authority agrees with Stanwell that competition could be improved if more focus was placed on improving customer engagement. Possible options for consideration may include:

(a) An advertising campaign to encourage customers to shop around for the best deal. Although Origin Energy argues that an advertising campaign is unlikely to be effective unless significant savings are available, the Authority notes that residential customers can access discounts to the Tariff 11 notified price of up to $150 per year for the 'typical' customer (consuming 4,250 kWh per year) and $300 for a large customer (consuming 10,000 kWh per year);

(b) Making it easier for customers to access and compare offers between retailers. A recent survey of residential energy customers in NSW found that customers did not rate the quality of information on electricity offers very positively and, although the Authority's price comparator enables customers to compare offers, the survey found that the awareness of IPART's price comparator was low[67];

(c) Reviewing customer protection mechanisms to ensure they are adequate and provide customers with sufficient confidence to venture into the competitive market;

(d) Removing barriers to customer switching, including termination fees where the contract price increases; and

(e) Adopting an 'opt-in' approach to price regulation under which customers must make an active decision to be supplied under a standard contract at the notified price[68].

[67] Roy Morgan Research, *Survey of Residential Customers of Electricity and Natural Gas in New South Wales: Effectiveness of Retail Competition*, 28 February 2013, p. 15, p. 42 & pp. 55-56.

[68] As noted by AGL and Simply Energy, an opt-in model has been raised as a possible option by IPART in its current pricing review. IPART has encouraged the NSW Government to consider introducing an opt-in model in the transition to price deregulation. As in NSW, this approach would likely require legislative change. See IPART, *Review of regulated retail prices for electricity, 2013 to 2016, Draft Report*, April 2013, pp. 40-42.

The Authority also notes that other aspects of this determination are likely to have a positive impact on competition. In particular:

(a) the energy cost estimate is now based on the 95th percentile of hedged outcomes (rather than the median) to minimise any residual volume or price risk retained in the hedging strategy (see Chapter 3);

(b) the ROC allowance and retail margin have increased and are likely to better reflect the retail costs and systematic risks that retailers face because they are based on more up-to-date analysis by IPART (see Chapter 4); and

(c) a cost pass-through mechanism has been included for the first time (see section 5.2).

On balance, the Authority considers that it is appropriate to maintain the current headroom allowance at 5% of cost-reflective prices for all retail tariffs, which is consistent with the Draft Determination and similar to the level of headroom that IPART has proposed in its recent draft determination. The Authority will continue to monitor the state of competition in Queensland, including the impact of its 2013-14 Determination, in order to inform its approach to future price determinations.

5.1.5 The Authority's Final Determination

The Authority will maintain the headroom allowance at 5% of cost-reflective prices for all retail tariffs.

5.2 Accounting for Unforeseen or Uncertain Events

In its 2012-13 Price Determination, the Authority considered that it would be appropriate to include some form of cost pass-through or carry-over mechanism to account for the material impacts of unforeseen or uncertain events on retailers' costs.

However, at that time, the Authority considered that it was not able to include an intra-year cost pass-through mechanism because it was only delegated the task of determining prices for one year, which it was required to complete by 31 May 2012, after which it had no ongoing role in administering the determination.

Similarly, the Authority also considered that it could not commit to a pass-through mechanism which could allow certain unforeseen costs from one year to be recovered through retail prices for the following tariff year, because it was only delegated the function of setting notified prices for the 2012-13 tariff year. There was always the chance that the Minister could have decided not to delegate the function to the Authority in future years, making any commitment potentially worthless.

The Authority has now been delegated the task of determining prices for a three-year period, but is still required to make annual price determinations. While this suggests that an intra-year cost pass-through mechanism to apply within a tariff year is still not possible (as the Authority is required to set prices annually, for the tariff year, in prospect), the Authority considers that it can now include a pass-through mechanism to allow for certain costs incurred during one tariff year to be recovered when setting prices for the following tariff year.

Approaches in Other Jurisdictions

A number of other regulators include cost pass-through mechanisms in their multi-year retail price determinations.

Australian Capital Territory

In its 2012-14 determination of retail prices for franchise electricity customers, the ICRC largely maintained its existing 2010-12 cost pass-through arrangements[69]. These arrangements prescribe two categories of eligible cost pass-through events – regulatory change events and tax change events. Regulatory change events include obligations regarding:

(a) any customer hardship program;

(b) retailer of last resort events;

(c) a green energy scheme, excluding the Australian Government's carbon pricing mechanism but including the RET scheme;

(d) changes in distribution or transmission charges; and

(e) the ACT Government's energy efficiency scheme.

The ICRC also allowed for the pass-through of costs associated with tax change events which included the imposition or removal of a relevant tax, as well as any change in the way a relevant tax is calculated.

To be considered for pass-through, ICRC requires that any unforeseen cost event must result in ActewAGL Retail incurring materially higher or lower costs such that the cost impact of the pass-through event is greater than 0.25% of ActewAGL Retail's revenue from regulated retail tariffs (during the most recent 12-month period).

New South Wales

IPART included a cost pass-through mechanism in its 2007 and 2010 retail price determinations to allow standard retailers to pass through certain material increases (and decreases) in costs, relative to the costs that were provided for in the determinations. The costs which could be considered for pass-through were limited to defined regulatory or taxation change events that were not anticipated, or were uncertain, at the time of the determination[70].

IPART applied a materiality threshold which requires the pass-through event to result in a standard retailer's efficient, incremental and justified average annual costs (or savings) over the term of the determination exceeding 0.25% of the standard retailers' total revenue from regulated retail prices for the year in which the event occurs.

In its April 2013 Draft Determination on 2013-2016 prices, IPART decided to retain the existing pass-through arrangements.

South Australia

For its 2010 price path determination[71], ESCOSA accepted there was a need to provide a pass-through provision for events which either impact only on AGL SA in its capacity as the declared standing electricity contract retailer, or impact on AGL SA disproportionately

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[69] ICRC, *Final Report: Retail prices for franchise electricity customers — 2012-14*, 8 June 2012, pp. 34-37.
[70] IPART, *Issues Paper: Review of regulated retail prices and charges for 2013 to 2016*, November 2012, p. 41.
[71] ESCOSA, *Final Inquiry Report & Final Price Determination 2010 Review of Retail Electricity Standing Contract Price Path*, December 2010, pp.112-113.

compared to other retailers. ESCOSA allowed AGL SA to seek the pass-through of amounts where an event has occurred which:

(a) is outside of the control of AGL SA;

(b) affects no electricity retailer other than AGL SA, or affects AGL SA disproportionately compared to other retailers;

(c) places a special burden on AGL SA in respect of its statutory obligations as the declared standing contract retailer; and

(d) gives rise to a material increase or decrease in the costs of AGL SA in meeting its statutory obligations as the declared standing contract retailer.

Tasmania

OTTER provided for an adjustment mechanism in its retail price investigation for 2010-11 to 2012-13[72], as required under state price control regulations[73].

The pass-through mechanism allows for an adjustment to prices as a result of a change in the costs of purchasing renewable energy certificates (REC) under the Renewable Energy (Electricity) Act 2000. Under the price control regulations, OTTER must ensure that the cost pass-through adjustment reflects the full financial impact to the electricity entity of the change in costs.

OTTER also allowed for an annual pass-through adjustment to reflect any differences between forecast and actual costs associated with AEMO participant fees and ancillary services.

Submissions

Responses to the Authority's consultation papers and Draft Determination provided mixed views on introducing a cost pass-through mechanism. The ERAA and electricity retailers (AGL, EnergyAustralia, Ergon Energy, Origin Energy, Momentum and QEnergy) supported the idea, while Australian Sugar Milling Council (ASMC), QCOSS, Queensland Consumers Association and MSF Sugar argued against the introduction of a pass-through mechanism.

AGL considered that without a mechanism for pass-through of costs related to unforeseen events, either within the price path or as a 'catch-up' for costs incurred in the previous year, retailers would face increased risk which should be acknowledged within notified prices. EnergyAustralia and Origin Energy were of a similar view, stating that, if such an arrangement is not possible under the Electricity Act or Delegation, the Authority should increase the retail margin accordingly.

All of the retailers that commented on this issue considered that the Authority should account for costs faced by retailers in prior tariff years where the price determination is materially different from the actual costs of supply during the year. For example, AGL, Origin Energy and QEnergy suggested that the Authority should implement a mechanism to allow for the under-recovery in SRES costs that has occurred previously. A similar issue was also raised by EnergyAustralia, Ergon Energy and Origin Energy, which suggested that the mechanism should apply during all three years of the delegation period, including in 2013-14 to allow pass-through of costs incurred in 2012-13. Origin Energy added that, if an

[72] OTTER, *Investigation of maximum prices for declared retail electrical services on mainland Tasmania - Final Report*, October 2010, pp. 101-102.
[73] *Electricity Supply Industry (Price Control) Regulations 2003.*

adjustment in 2013-14 was not possible, then the pass-through mechanism should ensure that any adjustment in 2014-15 accounted for under-recoveries incurred during 2012-13 and 2013-14. QEnergy also suggested that the catch-up be extended back to capture costs incurred during the past two years.

Ergon Energy suggested that the Authority should develop a materiality threshold to trigger the application of the pass-through mechanism. In contrast, AGL, EnergyAustralia and Origin Energy supported the decision to not set a fixed materiality threshold. Origin Energy suggested that a materiality threshold for pass-through events is unnecessary, as the time and cost to the retailer of preparing and submitting a proposal for pass-through provides its own materiality threshold. Origin Energy suggested that the onus should lie with a retailer to assess the impact of any unforeseen events and then apply to the Authority for a pass-through, if deemed significant. EnergyAustralia suggested that the events that should trigger a cost pass through should relate to any change that is made by a statutory or industry body that is outside of retailers' control, including decisions made by government, regulators and other government bodies, the tax office and distributors. EnergyAustralia suggested that it should also include events where an expected change is rescinded or substantially revised after costs have been incurred by retailers, for example, if the Queensland Government were to decide not to implement the National Energy Consumer Framework (NECF).

AGL and Origin Energy submitted that specific pass-through event categories should not be defined, and argued that categories such as 'regulatory reset' event and 'change in taxes' event are too narrow and do not capture the full range of events that could occur. Ergon Energy suggested that a material change in the costs of complying with government environmental schemes (for example, a final binding STP target significantly higher or lower than allowed for in the notified prices) or a material variance in NEM and ancillary service fees, should be potential triggers of the pass-through mechanism. QEnergy submitted that a cost pass-through mechanism could be triggered by changes to law and regulatory requirements, or the reopening of a price determination for Energex.

In contrast, ASMC, MSF Sugar, QCOSS and Queensland Consumers' Association were not in favour of a cost pass-through or catch-up mechanism. MSF Sugar argued that a cost pass-through mechanism for 'once-off' costs should not be considered unless it clearly sets out how these costs are to be offset against earnings from headroom and excessive margins.

QCOSS considered that it is generally not appropriate to revise tariffs based on unforeseen events as this deflects responsibility from retailers to mitigate the impact of such events (even though they are generally best placed to do so). QCOSS also questioned whether it was consistent with the Delegation for prices to be set that are not cost-reflective for a particular tariff year, given that they may include adjustments relevant to a previous tariff year due to pass-through amounts. QCOSS stated that it would be inequitable to pass such risks onto consumers who have no means of mitigating them and that retailers would lack incentives to control costs if they can pass those costs through to customers. QCOSS suggested that an exception may arise if a change of government policy required the Authority to make changes to regulated pricing during the tariff year. In that case, the Government should provide the necessary delegation for the Authority to implement any required changes.

QCOSS added that, if the Authority does implement a cost pass-through or catch-up mechanism, the provisions should be limited to events that are wholly outside an efficient representative retailer's control. QCOSS suggested that the events that might be considered for pass-through need to be tightly defined in the Authority's determination of prices and that the circumstances that might trigger a cost pass-through should be symmetrical and not be dependent only on retailer initiation. QCOSS also suggested that if a catch-up is implemented, it should be delayed to 2014-15 as it is likely to be complex with many parameters to consider.

The Queensland Consumers' Association supported the views of QCOSS on this issue.

The Government suggested that, if a pass-through mechanism is introduced, the criteria for determining eligible events should be transparent, well defined and offer improved certainty for retailers and consumers.

The Authority's Position

As noted at the outset, in previous retail price determinations, the Authority has been constrained in its ability to account for unexpected costs either by adjusting prices in the forthcoming tariff year for actual unforeseen costs incurred in an earlier year(s) or adjusting prices during the year for unexpected costs as they occurred.

However, the current Delegation passes responsibility for setting notified prices to the Authority for the period from 1 July 2013 to 30 June 2016. While this change would not allow for the Authority to adjust prices within the tariff year, the Authority considers it is no longer precluded from adjusting tariffs for the second and third years of the delegation period with an allowance for unexpected cost increases (or decreases) that were not provided for in setting tariffs for the first or second years of the delegation period.

Design of a Cost Pass-through Mechanism

Implications of the Form of Control

While there are some jurisdictional precedents of cost pass-through mechanisms for regulated electricity retail (and network) services, the examples discussed above are not all directly applicable to regulated retail pricing in Queensland, due to the form of regulation in place. In NSW, SA, ACT and Tasmania, the form of regulation applying to retail pricing for non-contestable customers is typically applied to specific retailers based on their forecast efficient costs of providing retail services during the relevant period. These forms of control rely on setting maximum revenues (or weighted average prices), rather than directly setting a schedule of tariffs, as is required under the Electricity Act in Queensland.

Another useful reference for cost pass-through mechanisms is the Authority's 2005 determination for electricity distributors Energex and Ergon Energy[74]. In that case, the Authority allowed for the pass-through of costs associated with certain major exogenous and unforeseen events that impacted significantly, either up or down, on the returns of the regulated business. This allowed for cost pass-through due to:

(a) changes in taxation (only where a change in taxation impacts on a change in tax payable holding everything else constant); and

(b) major changes in government policy (for example, if full retail contestability had been introduced).

As is the case with pass-through mechanisms applied by some other jurisdictional regulators, the Authority's 2005 distribution cost pass-through framework was designed to function alongside a revenue cap form of regulation, as opposed to a schedule of notified prices. This is an important distinction which, for a number of reasons, will influence the nature of a pass-through mechanism to apply in Queensland.

[74] QCA, *Final Determination: Regulation of Electricity Distribution*, April 2005.

Firstly, as the task is to develop a single set of maximum notified prices applying to all retailers with non-market customers, there is no scope to pass through costs that are unique to individual retailers. Consequently, any pass-through can only be for events which have an equal incidence on all retailers, to the extent that they supply electricity at notified prices. This requirement limits the types of costs which can be considered for cost pass-through to changes in uncontrollable and unavoidable costs which apply to all retailers in the course of supplying electricity to non-market customers.

Secondly, as pass-through costs cannot be specific to a particular retailer, materiality of costs for pass-through cannot be determined on the basis of some proportion of the retailers' regulated revenues, as is the approach in other jurisdictions. This issue is discussed further below.

Notwithstanding these differences, the Authority considers that the key principles of existing jurisdictional pass-through mechanisms can be drawn upon to develop a cost pass-through framework for setting notified prices in Queensland.

Principles for a Cost Pass-through Framework

While the Authority considers it reasonable to provide some flexibility for retailers to recover the efficient costs associated with certain unforeseen and unavoidable events, providing this flexibility should be subject to clear guidelines and a high degree of discretion on the Authority's part. This is necessary to ensure that pass-through provisions are not over-used or susceptible to regulatory gaming at the expense of Queensland electricity consumers. Clear principles on how cost pass-throughs will be applied are also important to minimise regulatory risk and uncertainty for retailers and customers.

The Authority considers that a fair and efficient cost pass-through mechanism for Queensland should accord with the following objectives and criteria:

(a) the mechanism should be simple, transparent and not administratively costly or complex;

(b) it should offer improved certainty for retailers and electricity consumers, along with fairer sharing of risks;

(c) it must (by virtue of the current form of regulation) only apply to unforeseen costs that are of equal incidence to all retailers in Queensland that supply electricity to non-market customers;

(d) it should operate symmetrically in response to both cost increases and decreases; and

(e) it should be subject to clear guidelines for its application.

What Costs Should be Eligible for Pass-through?

As noted previously, in Queensland, regulated retail tariffs are not tailored to a particular retailer. Rather, they are based on the estimated costs likely to be incurred by a representative retailer. Compared to other jurisdictions, this limits the scope of costs which can be captured by a pass-through mechanism and how materiality is defined.

As notified prices apply consistently across all retailers, there is only scope to provide pass-through adjustments arising from previously unforeseen costs which have equal incidence upon all retailers in Queensland. To this end, eligible cost pass-through events should be limited to significant, broad-reaching changes such as regulatory and policy changes imposed by State or Federal Government agencies, and changes in taxation.

Under the Authority's N+R approach to calculating notified prices, many significant changes in retailers' costs will automatically be reflected in the inputs used to develop tariffs. Combined with the annual frequency of tariff determinations, the current framework in Queensland inherently captures the impact of many events that may otherwise give cause for cost pass-throughs between tariff determination processes.

However, there are some non-systematic risks which are still borne by the retailers under the current framework. An example, noted by retailers in submissions, is the impact of differences between estimated and actual binding SRES liabilities each year.

Pass-through of Under-recovered SRES Liabilities

In recent years, actual binding STP targets and resulting SRES liabilities for retailers have varied considerably from the best estimates available to the Authority at the time of setting notified prices. Origin Energy claimed that the costs borne by retailers due to these under-recoveries were amounting to tens of millions of dollars.

In the Draft Determination, the Authority considered it would be reasonable to allow the pass-through of SRES costs, where the amounts provided in a determination are found to be materially understated (or overstated) due to differences between binding and non-binding STP targets.

However, the Authority does not accept Origin Energy's suggestion to pass-through unrecovered 2012-13 SRES costs into notified prices for 2013-14, nor does it intend to adjust 2014-15 prices for two years of previous under-recoveries, as suggested by QEnergy. As proposed in the Draft Determination, the Authority will contemplate the pass-through of SRES costs incurred during 2013-14 while setting prices for 2014-15, because the mechanism should only be applicable once the decision has been made (not retrospectively) and relate to costs incurred within the three-year delegation period. Similarly, the Authority has decided that the recovery of any such costs should occur during a tariff year within that same delegation period.

Differences in Network Cost Estimates

Another potential cost pass-through could arise due to the timing of annual approvals for Energex and Ergon Energy's network charges. Under the current timeframes, the Authority must base its final notified prices on distribution charges which have yet to be formally approved by the AER. If the final AER-approved charges were to vary materially from those used by the Authority in setting final notified prices, it would be preferable to correct for any differences by adjusting the regulated tariffs in the current tariff year but, as the Authority considers that is still beyond its ability, the impact of this difference could be captured in setting notified prices for the following tariff year, using a pass-through adjustment.

Criteria for Determining Eligible Costs

Two situations where a pass-through of costs may be appropriate are noted above and the Authority has decided to specifically recognise these in setting out the pass-through arrangements (subject to materiality and other criteria being met) for this delegation period.

In response to the Draft Determination, Origin proposed a more detailed list of eligible events including (but not limited to) regulatory events such as additional obligations related to green energy schemes; a retailer of last resort event; additional obligations relating to Government-imposed energy hardship policies; one-off AEMO charges (such as reserve trader or direction events); and new taxation events.

However, the Authority considers that it is not practical to publish an exhaustive list of possible eligible pass-through events. As the Authority noted in its 2005 determination on electricity distribution regulation, most eligible pass-through events will, by definition, be either unforeseen or uncertain and therefore unable to be detailed in advance. To the extent that unforeseen costs arise during a tariff year, the Authority will consider each event on its merits (against general criteria and principles) when determining whether to include an adjustment to notified prices in a subsequent tariff year.

As general principles, the Authority considers that pass-through costs should generally:

(a) be limited to significant exogenous, unforeseen (or otherwise uncertain at the time of the determination) and unavoidable costs which are of equal incidence to all Queensland electricity retailers with non-market customers;

(b) not have been provided for, or otherwise already recovered, through other means (such as the margin); and

(c) be limited to those which have a material impact on retailers and/or electricity consumers.

The cost pass-through provisions will act symmetrically to also capture any unforeseen events which decrease out-turn costs compared to the determination. This will ensure that the pass-through mechanism allows retailers to better manage the risks they face while also returning the benefit of any lower than expected costs back to customers through lower regulated tariffs in subsequent years.

In its submission, Origin Energy suggested that an estimated allowance for expected future cost events should be included in notified prices, followed by an adjustment in later years should the estimate prove to be too high or low.

However, the Authority does not consider this to be an appropriate purpose for a cost pass-through mechanism. Adopting such an approach would likely lead to a complex 'overs and unders' approach to cost recovery, which would represent a further departure from the intent of the Delegation and the Electricity Act. The Authority considers that its pass-through mechanism is sufficient to deal with unforeseen or uncertain cost events, where required, without creating unnecessary complexities and 'cost of service' regulatory outcomes.

Materiality

For an event to be considered for pass-through, the incremental impact of the unforeseen cost should generally be demonstrated to be material. This will prevent the cost pass-through mechanism creating a cost of service regulatory model where it is used to recover relatively minor unforeseen costs which would typically be absorbed by an efficient, competitive retailer. The intention of the cost pass-through provision is not to insulate retailers from every unforeseen event that might occur during the tariff year, rather it is to redress any material over- or under-recovery of efficient costs due to significant unforeseen, uncontrollable, exogenous events.

EnergyAustralia supported the Authority's position to not prescribe a materiality threshold but suggested that the primary determinant should be the commercial impact on retailers. EnergyAustralia considered that the impact on customers of a cost pass-through amount should be limited to how the costs are best applied to tariffs as a fixed or variable amount and to which tariffs they should be applied.

EnergyAustralia considered that a materiality clause was not necessary because the proposed mechanism only allowed for a cost pass-through amount to be included at the time of an annual price determination. Even if the pass-through amount was small, there would be no additional costs incurred by retailers in implementing tariff changes as tariffs will be changing regardless.

In contrast, Momentum, the ERAA and ESAA considered that the proposed approach to determining materiality was not appropriate and a more robust measure was needed. The ERAA and ESAA submitted that the proposed criteria were subjective and relied heavily on the Authority's discretion regarding cost pass-through elements. Momentum argued that the proposed mechanism did not fully represent the asymmetric risk borne by retailers. Momentum pointed to the cost impact of environmental schemes and the potential for changes under an alternative Federal Government, arguing that the Authority should provide scope to pass through costs due to potential changes to these schemes.

While the Authority does not agree that more robust or prescriptive criteria for determining materiality are necessary, it does not consider that materiality should be ignored, as suggested by EnergyAustralia. It is important that the Authority retains discretion regarding how the pass-through mechanism might be applied, particularly as it is a new and untested element of retail price regulation in Queensland. This, in conjunction with the fundamental requirement that any cost events must be of equal incidence to all retailers with non-market customers, should ensure that over-use, or gaming, of the mechanism is unlikely to be a concern.

Consistent with its position in the Draft Determination, the Authority has not defined a fixed materiality threshold at this stage, to avoid constraining the scope of its considerations when assessing proposals for the pass-through of unforeseen costs. The notion of materiality is subjective and difficult to define, particularly in isolation of other elements to which retailers and customers are exposed. Setting a rigid materiality threshold could limit the extent to which the Authority can consider the pass-through of costs. However, the absence of a prescribed materiality threshold does not mean that the Authority will necessarily entertain the pass-through of unforeseen costs or savings which are trivial.

When considering whether to include a pass-through amount, the Authority will not only look at the impact of that change on retailers' costs, but also the likely impact of the pass-through on retail electricity prices for consumers. For example, the Authority may not be convinced to allow a pass-through of a small under-recovery of SRES costs if it is accompanied by a similar unforeseen reduction in other costs which reduce the incremental impact of the under-recovery.

Conversely, in the interests of consumers, it may be appropriate in some cases to pass through relatively small unforeseen incremental savings that might otherwise be considered immaterial, particularly if other rising costs are putting pressure on customer electricity bills. The need for cost pass-throughs (and their materiality) is best considered against the backdrop of broader drivers of retailers' costs and electricity prices. The Authority considers this is most appropriately assessed on a case-by-case basis without a pre-determined materiality threshold, which could direct the Authority to an inappropriate outcome.

At a high level, the Authority intends to consider the materiality of potential cost pass-throughs against two criteria:

(a) the impact of the change in costs on the returns of the retail businesses; and

(b) the impact of the cost pass-through amount (positive or negative) on regulated retail electricity prices and average customer bills.

Approval and Application of Pass-through Amounts

The Authority proposes to allow retailers or consumer groups to submit proposals for a cost pass-through as they see fit, given the general guidelines noted above. However, reasonable proposals will be consulted upon during the annual price determination process and any resultant adjustment to notified prices will only take effect from the start of the next relevant tariff year. No adjustments to notified prices will be made during the course of a tariff year. The Authority also reserves the right to initiate its own reviews which may lead to a pass-through of costs or savings in a subsequent tariff year.

In response to the Draft Determination, QCOSS posed a number of detailed questions regarding how pass-through amounts would be calculated and applied. The questions raised by QCOSS highlight the complexities that need to be considered when determining pass-through amounts and reinforce the need for the Authority to maintain broad discretion over how the mechanism will be applied in each case. For example, depending on the timing of unforeseen costs emerging during a particular tariff year, there may be a need for the pass-through amount to be adjusted by a suitable discount rate (or rates) to reflect the time-value of unrecovered costs.

These matters of detail will be addressed by the Authority when it is presented with a reasonable proposal for cost pass-through during the course of the Delegation period.

Conclusion

The Authority will consider using a cost pass-through mechanism during the current delegation period, commencing in the 2014-15 tariff year. This mechanism will allow retailers to recover the efficient costs or savings arising from certain, unavoidable and unforeseen events, at the Authority's discretion.

In general terms, the Authority considers that costs for pass-through should be directly related to unforeseen, exogenous and unavoidable events such as changes in legislation, taxation and other significant costs arising from decisions made by State and Commonwealth agencies.

The Authority has not prescribed an exhaustive list of specific cost events which it considers should be eligible for cost pass-through, nor has it set a fixed materiality threshold for the pass-through of those costs. Rather, the Authority will recognise two specific events as possible pass-through candidates and will assess other potential pass-through events against the defined criteria set out in this section.

The Authority recognises that differences in SRES costs where the amounts provided in a determination are found to be materially understated or overstated, and any differences in network charges (in the event that the final AER approved charges differ from those used by the Authority in its annual price determinations), would be eligible pass-through events, subject to the Authority's view on the materiality of those costs in any given year.

Limiting the availability of the pass-through mechanism to these two situations at this stage strikes a reasonable balance between the concerns about the potential for regulatory gaming (as raised by customers and consumer groups), with the expectation that retailers should have the opportunity to recover the efficient costs of uncontrollable events. However, it does not preclude the Authority from considering other events for cost pass-through, on a case-by-case basis.

Similarly, with regard to materiality, the Authority maintains its decision to not prescribe a firm threshold, preferring to consider each proposed cost pass-through on its merits, in conjunction with other relevant factors.

5.3 Other Issues

A number of submissions raised issues regarding the application, eligibility criteria or structure of regulated tariffs in Queensland. Each of these is discussed in turn.

The Large Customer Threshold

A number of submissions queried the level of the threshold between small and large customers and how customers are categorised as small or large.

The small/large customer threshold is defined in the Electricity Regulation and cannot be changed by the Authority as part of setting notified prices.

Customers have access to notified prices for small or large customers that are based on the network tariff against which Energex or Ergon Energy decide the customer is to be charged.

Tariff Classification of Bodies Corporate

The Shopping Centre Council raised the issue of residential bodies corporate that consume more than 100 MWh annually being unable to access residential tariffs, as distributors have classified them as commercial customers.

The gazette notice has been amended to allow residential bodies corporate consuming more than 100 MWh annually to access regulated prices.

Separation of Costs on Electricity Bills

The Bundaberg Region Irrigators Group (BRIG) suggested that customer bills should be itemised to show each cost component, the carbon tax, green/renewable energy costs, other costs, as well as the level of the CSO subsidy attributed to the particular consumer bill.

While the Authority agrees with BRIG that this would be useful information for electricity customers to have made available to them, as it would enhance their understanding of where costs are being incurred and provide useful information to guide their decisions on energy use, the Delegation requires that the Authority determine bundled charges for notified tariffs, which largely precludes provision of this information. Retailers have also been resistant to any suggestions in the past that unbundled information be provided on bills.

Application of the CSO

Some stakeholders suggested that the CSO subsidy paid to EEQ should also be paid to other retailers, or to Ergon Energy’s distribution business, in order to allow retail competition to develop in regional areas. These suggestions from customers appeared to be driven largely by service and service quality concerns and the lack of choice in service provider.

While changing the arrangements for delivering the CSO should enable greater penetration of competition into regional areas, this is a matter for the Queensland Government to decide.

On-selling

Some submissions raised concerns related to electricity on-selling. Electricity on-selling occurs where an organisation or customer, such as a body corporate, purchases electricity in bulk for delivery to its main metering point, which is then distributed throughout the property and occupants of the property charged by the bulk purchaser (for example, body corporate) for their individual consumption. On-selling arrangements are set out in the Electricity Act and administered by the Department for Energy and Water Supplies (DEWS), which has recently released a discussion paper on the issue in order to provide input to the Queensland Government's Inter-Departmental Committee on reform of the Queensland electricity market.

On-selling arrangements are therefore beyond the scope of the Authority's current pricing review.

Rural Subsidy Scheme

AgForce questioned how the Rural Subsidy Scheme would operate once the transition of farming and irrigation tariffs was complete. Arrangements in relation to the Rural Subsidy Scheme are determined by the Queensland Government and are set out in the Gazette Notice, which provides for the waiving of fixed charges and deferral of payment for farmers in drought-declared areas (subject to various criteria), regardless of which tariff the farmer is on.

Exporting Energy to the Network

Some stakeholders made suggestions in relation to the export of energy to the network. For example, ASMC suggested that its role as a large exporter of energy to the network should be considered by the Authority in setting notified prices. MDIA Council suggested that a large-scale solar PV feed-in tariff should be established for irrigators to allow them to offset the costs of the Solar Bonus Scheme and electricity in general.

However, the Delegation requires the Authority to determine notified prices for customer retail services, which are defined under the Electricity Act as the sale of electricity to customers. The Authority has no role in setting prices for the purchase of electricity from customers and will not be considering this issue in this review.

The Authority notes that there is nothing preventing customers from negotiating power purchase arrangements for exported energy with retailers or other parties.

Tariff 66 Temporary Disconnections

The MDIA Council pointed out that the wording of the terms and conditions for Tariff 66 in the draft Gazette Notice indicated a ban on customers temporarily disconnecting from the tariff. This condition was included in the Gazette Notice for the previous year when it was anticipated that the tariff would become obsolete from 1 July 2013. For 2013-14, the wording has been changed to that used in previous years, specifically:

> *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.*

Reversion to Obsolete Tariffs Being at the Discretion of Distributors

The MDIA Council argued that the ability to revert to obsolete tariffs should be automatic and not at the discretion of distribution entities. This requirement has been removed from the final Gazette Notice.

6. TRANSITIONAL ARRANGEMENTS

The Delegation requires the Authority to consider:

(a) for the standard regulated residential tariff (Tariff 11), implementing a three-year transitional arrangement to rebalance the fixed and variable components of Tariff 11, so that each component (fixed and variable) of Tariff 11 is cost-reflective by 1 July 2015;

(b) for the existing obsolete tariffs (farming, irrigation, declining block, non-domestic heating and large business customer tariffs), implementing an appropriate transitional arrangement should the Authority consider there would be significant price impacts for customers on these tariffs if required to move to the alternative cost-reflective tariffs; and

(c) for the large business customer tariffs introduced in 2012-13 (Tariffs 44, 45, 46, 47 and 48), whether customers on these tariffs should be able to access the transitional arrangements for the obsolete large business customer tariffs, should the Authority consider that a transitional arrangement for the obsolete tariffs is necessary.

6.1 Rebalancing the Fixed and Variable Charges in Tariff 11

Tariff 11 is the standard regulated residential retail tariff for customers who are not on market contracts. For 2012-13, the Government froze Tariff 11 charges at their 2011-12 levels (with an addition to the variable charge to account for the impact of the carbon tax), rather than setting charges at the cost-reflective levels estimated by the Authority. To implement this decision, the Government directed Energex to lower the fixed component of its network charge to retailers for residential customers on retail Tariff 11 (network tariff 8400) in order to compensate retailers for lost revenue as a result of the tariff freeze and then subsequently subsidised Energex for its lost revenue. The Government's decision to freeze Tariff 11 was for the one year only (2012-13).

As a result of the above arrangements, the fixed charge for Tariff 11 is 26.170 c/day, which is significantly lower than the 2012-13 cost-reflective level of 78.578 c/day estimated by the Authority for 2012-13. By contrast, the variable charge under Tariff 11 is 23.071 c/kWh, which is higher than the estimated cost-reflective level of 20.134c/kWh[75].

To undo the freeze arrangements, the Authority proposed an immediate switch to a cost-reflective Tariff 11 in its consultation papers, but noted that the Delegation requires the Authority to consider implementing a three-year transitional arrangement to rebalance the fixed and variable components so that each component is cost-reflective by 1 July 2015.

In the Draft Determination, the Authority proposed a transitional arrangement of three equal increases to the fixed component of Tariff 11, bringing it to a cost-reflective level by 1 July 2015. The variable component was adjusted to ensure that retailers would be no worse off than if there was an immediate move to cost-reflective pricing in 2013-14. The Authority has maintained this approach for the Final Determination.

[75] 2012-13 Tariff 11 charges in the *Queensland Government Gazette*, Vol. 360, No. 43, 29 June 2012, available at: http://www.bookshop.qld.gov.au/documents/06.07.12Combined.pdf; cost-reflective Tariff 11 charges as per the Authority's advice to the Minister for Energy and Water Supply, 5 June 2012, available at http://www.qca.org.au/files/ER-QCA-NEP1213-AdviseTariff11-0612.PDF

Submissions

Retailers strongly objected to the freezing of Tariff 11 and suggested that it would have a range of detrimental impacts, including increasing risks for retailers and reducing competition and investment in the Queensland electricity market. Some retailers, including Origin Energy and EnergyAustralia, suggested that the freeze would result in higher future prices than would otherwise have occurred. Retailers, ERAA and ESAA suggested that retailers and distributors should not have to bear the cost of efforts to curb electricity prices and that it was important for retailer revenues to be maintained at the levels they would have been in the absence of the tariff freeze.

Retailers generally supported moving to cost-reflective fixed and variable charges as soon as possible. Some retailers suggested that if a three-year transition period was required, then it would be appropriate to make a large initial adjustment, to ensure retailers do not subsidise the transitional charges, followed by smaller adjustments to finish rebalancing the fixed and variable charges. Nevertheless, in response to the Draft Determination, AGL, Origin Energy and Energy Australia did not consider the Authority's proposed approach to be unreasonable. Origin Energy stressed that a transition period longer than three years was undesirable, as it would continue to deny large electricity users (including some vulnerable households) the benefits of cost-reflective pricing.

In contrast to retailers, customer representative groups and the Queensland Government suggested that the transition to cost-reflective charges for Tariff 11 should occur over the three-year Delegation period and generally favoured a small initial adjustment followed by larger adjustments.

The Association of Independent Retirees (AIR) suggested that households needed as much time as possible to adjust to electricity price increases and that a small initial increase would allow time for customer education and engagement. The Government suggested that anticipated future decreases in network charges could allow for a smoothed price path, thereby enabling larger increases to be postponed to the end of the Delegation period. National Seniors Australia (NSA) suggested a staged return to cost-reflective charges should be implemented by discounting the network charges.

QCOSS submitted that an extended transitional period was essential to assess the impact of increased prices on consumers, ensure that support mechanisms could be appropriately adjusted to facilitate customer education, and to enable vulnerable households to make informed decisions about electricity pricing structures and to change consumption patterns where possible.

QCOSS also suggested that the transition pathway for Tariff 11 should be determined by the impacts on consumers most vulnerable to cost increases and suggested the Authority should conduct a detailed assessment of customer impacts, including current electricity concessions available in Queensland.

Retailers and distributors expressed concerns about vulnerable customers, but noted the unfairness and inefficiency of the cross-subsidises in the current Tariff 11 structure and suggested that welfare concerns could be addressed far more efficiently via direct, targeted policy measures. Similarly, EnergyAustralia, Origin Energy, the ERAA and ESAA suggested that delivering welfare assistance via regulated electricity prices benefited customers according to their electricity usage, as opposed to benefiting those most vulnerable. ERAA and ESAA also suggested that restricting energy tariffs masked one of the symptoms of financial hardship, rather than providing direct assistance, and that the only sustainable long-term approach to assist people in hardship was a comprehensive welfare framework.

Customer groups made a range of suggestions to mitigate the effects of increasing electricity prices, including: reviewing current welfare arrangements; establishing a tariff for financially vulnerable customers; providing free smart meters to seniors; ensuring that all retirement and residential village residents have access to Tariff 11; developing appropriate concessions and support for energy efficiency; and implementing an extensive media campaign to inform consumers of both the increasing costs of Tariff 11 and opportunities for them to reduce their exposure to higher prices. While some of these suggestions may have merit, they are beyond the scope of the current exercise.

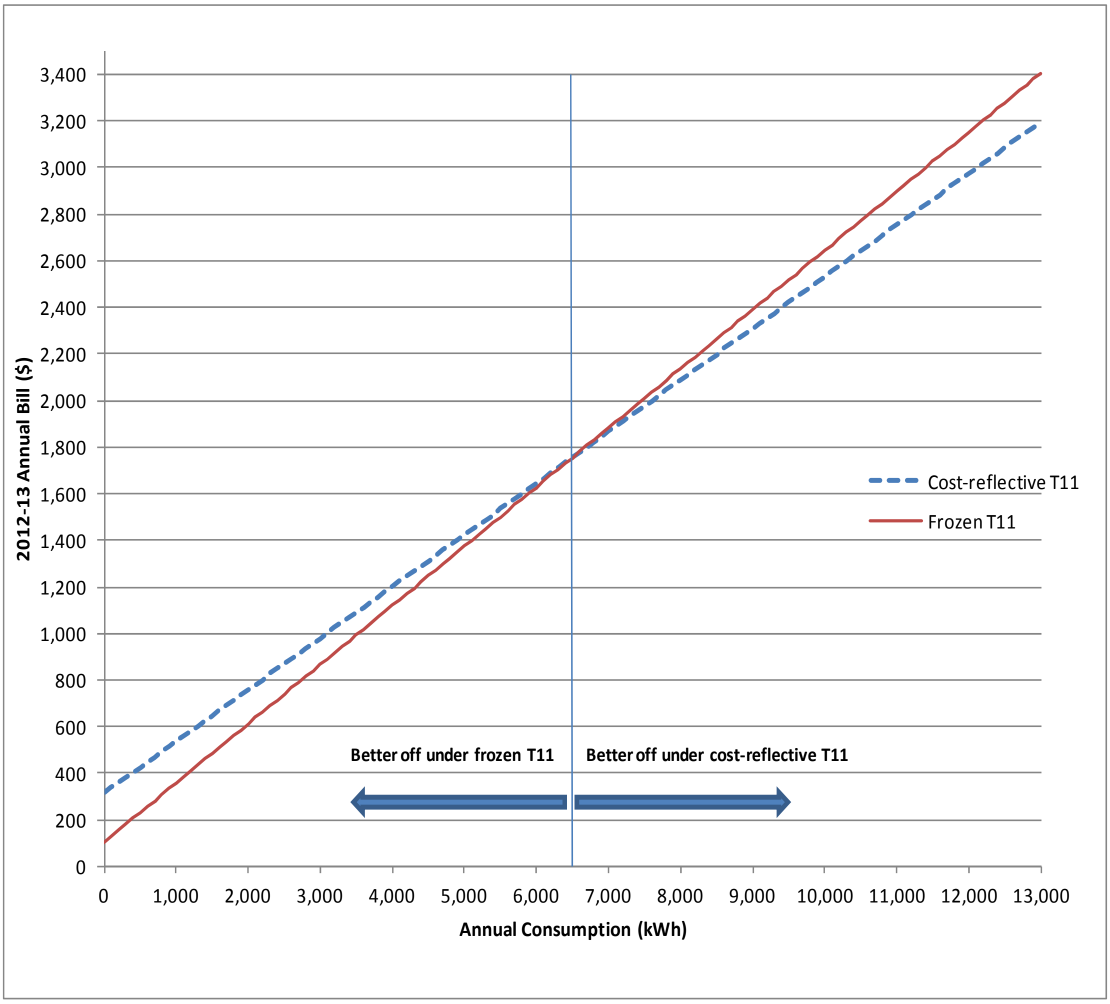
Energex, AGL, and the Government suggested that Tariff 11 should also be re-balanced with a view to increasing the financial attractiveness of Tariff 12 during the transition period.

The Authority's Position

The difference between the frozen 2012-13 Tariff 11 charges and what would have been the cost-reflective charges means that customers consuming less than around 6,500 kWh per year are better off on the frozen Tariff 11 than they would be on a cost-reflective Tariff 11. The amount these customers save due to the lower frozen fixed charge outweighs the cost of the frozen higher variable charge. As shown in Figure 6.1, the lower a customer's level of consumption, the greater the saving they make relative to a cost-reflective Tariff 11.

In contrast, customers who consume more than around 6,500 kWh per year are worse off on the frozen Tariff 11 than they would be on a cost-reflective Tariff 11. The amount these customers save due to the lower frozen fixed charge is less than the extra cost they incur on the higher frozen variable charge. The extent of this detriment increases the higher the customer's level of consumption.

Figure 6.1: 2012-13 Annual Electricity Bills — Cost-reflective and Frozen T11



The Authority agrees with submissions that this cross-subsidy between larger and smaller customers is distorting Queensland's electricity market and denying the benefits of cost-reflective tariffs to those customers that would be better off. The Authority disagrees that retailers' risks are any higher than previously, because the tariff freeze simply perpetuated the prevailing lack of cost-reflectivity that had been present in Tariff 11 up to 2011-12.

The Authority considers that, from an economic perspective, a single step-change to a cost-reflective Tariff 11 in 2013-14 would be the preferred path to correct the distortions in Tariff 11 charges and agrees with retailers that any perceived adjustment or social welfare implications would be best addressed separately via targeted welfare assistance.

However, the requirement in the Delegation and submissions from other stakeholders suggest that a three-step approach to transitioning to cost-reflective Tariff 11 prices is considered more desirable, with at least some rebalancing of fixed and variable charges achieved in each year.

As noted above, Energex's fixed network charge for residential customers was lowered in 2012-13 in order to compensate retailers for lost revenue resulting from the retail tariff freeze. However, Energex has indicated that it considers its Tariff 11 fixed and variable network charges proposed for 2013-14 to be cost-reflective.

If the move to a cost-reflective retail Tariff 11, in terms of the mix of fixed and variable charges, is to be spread over the three years of the current delegation period, the only question to decide is the reasonable annual increase in the fixed component of Tariff 11 given the gap between the current fixed charge and the required cost-reflective fixed charge. A simple approach would be to move the fixed charge in three equal increments.

While the required increase in the fixed charge is being transitioned over three years, the variable charge must also be adjusted annually to leave retailers no worse off than they would have been had the move to cost-reflectivity been made in one step in 2013-14. This is only reasonable as retailers' costs are not being transitioned over this period and they will be incurring their true 2013-14 costs. By adjusting the variable charge to offset the loss to retailers from transitioning the change in the fixed charge, in effect, larger residential customers are being required to subsidise the cost of the lowered transitional fixed charge.

Table 6.1 shows the three equal increases (in 2013-14 values) in the fixed charge that would be needed to transition from the frozen fixed charge in 2012-13 to the cost-reflective fixed charge for 2013-14.

Table 6.1: Transitional Charges for Tariff 11 (Based on Constant 2013-14 Costs[1])

Tariff Component	*Cost-reflective 2012-13*	*Cost-reflective 2013-14*	*Frozen 2012-13*	*Transitional 2013-14*	*Indicative transitional 2014-15*	*Indicative transitional 2015-16*
Fixed charge[2] (c/day)	78.578	98.316	26.170	50.219	74.267	98.316
Variable charge[2] (c/kWh)	20.134	22.969	23.071	26.730	24.849	22.969
Annual Bill[3,4] ($)	1,350	1,575	1,290	1,575	1,575	1,575

1 *The charges presented for 2014-15 and 2015-16 are indicative only as they are based on costs remaining constant at 2013-14 levels. These will change with changes in underlying costs.*
2 *GST Exclusive.*
3 *Based on Energex's forecast of average consumption by residential customers in 2013-14 of 4,671kWh.*
4 *GST Inclusive.*

Table 6.1 also shows the offsetting adjustments required to the Tariff 11 variable charge in order to pay for the non cost-reflective fixed charges across the transitional period. The average annual bill for customers (and hence the average annual revenue for retailers) is maintained (at $1,575) across the transitional period by the offsetting adjustments to the variable charge.

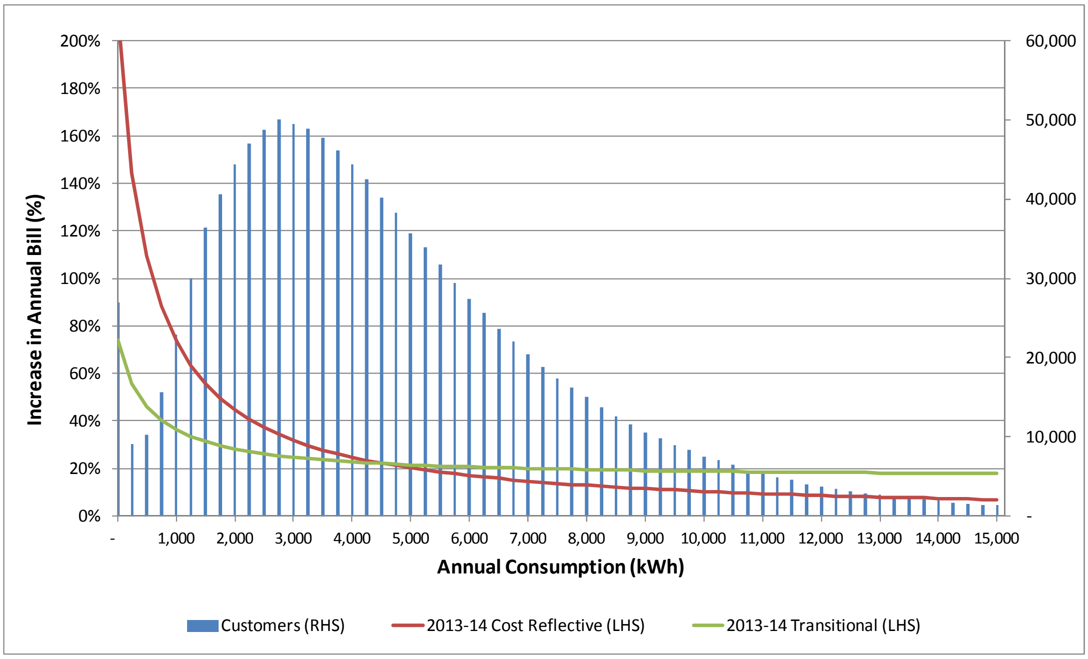
It must be recognised that the end target for the fixed component is in 2013-14 dollars and assumes nothing else changes over the transitional period (an unlikely outcome but the only assumption that can be made at this time). As underlying network charges and other costs are likely to change in the future, the retail tariff charges presented for 2014-15 and 2015-16 are indicative only and will need to be recalculated each year using up-to-date information.

Consumer Impacts

The transitional charges for 2013-14 presented in Table 6.1 are significantly higher than the frozen charges for 2012-13 and will increase an average customer's annual bill from $1,290 to $1,575. This increase is made up of $60 to close the gap between the frozen Tariff 11 charges and the cost-reflective Tariff 11 charges and a further $225 which reflects the underlying increase in the cost-reflective charges for Tariff 11 between 2012-13 and 2013-14.

As noted by QCOSS and other stakeholders, increases in the fixed charge will have a disproportionate impact on customers with low levels of consumption. Figure 6.2 shows how much customers' annual bills will increase in percentage terms by moving from the frozen Tariff 11 charges for 2012-13 to the transitional Tariff 11 charges for 2013-14 presented in Table 6.1, across a range of consumption levels. It is clear that the further a customer's level of consumption is below average, the larger the percentage increase in their bill will be.

Figure 6.2: Bill Impacts from Moving to Transitional and Cost-reflective Tariff 11 Charges



The Authority is also mindful that customers with relatively high levels of consumption will also include financially vulnerable customers for whom the level of the variable charge is far more important, in terms of its impact on their bills, than the fixed charge.

Unfortunately, there is little scope for a much smaller increase in the fixed charge since any further reduction in the fixed component has to be offset by increases in the variable component which has already been pushed well above its cost-reflective level. While this approach to transitioning benefits small consumers, the Authority is mindful that customers with relatively high levels of consumption will also include financially vulnerable customers, for whom the level of the variable charge is far more important, in terms of impact on their bills, than the fixed charge.

Conclusion

Given the magnitude of bill impacts on customers with low consumption, the Authority considers that increasing the fixed charge one-third of the way toward cost-reflectivity represents an upper limit to the re-balancing of the fixed and variable charges for 2013-14.

The Authority also considers that this strikes an acceptable balance between holding down the fixed charge to ease the financial pressure on small consumers and moving the variable charge further away from its cost-reflective level to the detriment of larger consumers.

The Authority's Final Determination on Tariff 11 is presented in Table 6.2. The increase to the fixed charge is 3.261 c/day higher than proposed in the Draft Determination, as the underlying costs were higher than anticipated. In addition, Energex revised downwards its forecast of average consumption by residential customers. As a result, the variable charge has increased to 26.730 c/kWh, which is marginally higher than proposed in the Draft Determination.

Table 6.2: Final Transitional Charges for Tariff 11

Tariff Component	*Frozen 2012-13*	*Draft Transitional 2013-14*	*Final Transitional 2013-14*
Fixed charge[1] (cents/day)	26.170	*46.958*	*50.219*
Variable charge[1] (cents/kWh)	23.071	*26.693*	*26.730*
Annual Bill[2,3] ($)	1,290	1,560	1,575

1 GST Exclusive.
2 Based on Energex's forecast of average consumption by residential customers in 2013-14 of 4,671kWh.
3 GST Inclusive.

Further analysis of the impacts on different types of customers is presented in Chapter 7, along with a summary of current concession arrangements. It is open to the Government to consider whether additional assistance measures may be appropriate for some consumers facing higher cost increases.

6.2 Transitional Arrangements for Obsolete Tariffs

In 2012-13, the Authority introduced a range of new cost-reflective tariffs for use by small and large businesses, made 12 tariffs obsolete and removed three of the old regulated tariffs. In recognition of both the significant financial impact on many customers and the practical constraints of moving to different tariff structures (for example, because of the need to update or replace meters) a transitional period of one year was put in place to allow time for meter upgrades and affected customers to adjust business operations where possible to minimise the impact of moving to the new tariffs. The Authority also indicated that it would review the state of progress in transitioning customers to the new tariffs when setting the prices for 2013-14. The tariffs subject to transitional arrangements were Tariffs 21, 37, 62, 63, 64, 65, 66, 20 (large), 22 (large), 41 (large), 43 (large) and 53 (large).

The Delegation requires the Authority to consider whether further transitional arrangements are required. The Authority released a consultation paper seeking feedback specifically on transitional issues and hosted workshops in regional Queensland to gain a more detailed understanding of the issues being faced by customers. The Draft Determination set out three proposals for these tariffs: a seven year transitional period for those tariffs where moving to the appropriate cost-reflective tariff would cause significant price impacts for customers; increases in tariffs of 11% (Tariffs 41 and 43), 12.5% (Tariffs 20 and 22), 17.5% (Tariffs 62, 65 and 66) and 21% (Tariffs 21 and 37) and; opening of access to some transitional tariffs for both small and large customers. In addition, the Authority proposed removing Tariffs 53, 63 and 64.

The feedback gained at the regional workshops was extremely useful and many attendees backed this up with formal submissions addressing relevant issues. The Authority understands that participation in this type of process is not a normal day-to-day activity for many customers and recognises the efforts made to make a valuable contribution.

Approaches in Other Jurisdictions

The specific issues being faced in regional Queensland have not been experienced in other states. While it has some legacy subsidised tariffs, Country Energy in New South Wales is able to set transitional price paths to cost-reflective tariffs under a Weighted Average Price Cap. The level of subsidy to rural and regional areas of Queensland is somewhat unique and presents particular problems in bringing prices more into line with the costs of supply.

Submissions

Almost all submissions advocated the extension of transitional arrangements, citing potential significant financial detriment if required to move to cost-reflective tariffs on 1 July 2013.

A large number of individual farmers and irrigators and representative groups including QFF, Canegrowers, Canegrowers Isis, Cotton Australia and MDIA Council suggested there was a need to reinstate a time-of-use irrigation tariff. All indicated that there had been significant historic investment made in configuring pumping equipment to maximise usage in off-peak (evening) times, which they suggested also increased water use efficiency by minimising evaporation and wind interference. These stakeholders, and others such as SunWater and Bundaberg Walkers Engineering Ltd (BWEL), were concerned that the lack of effective price signals in the cost-reflective tariffs encouraged consumption in peak times, thus increasing peak demand.

Many submissions from individual farmers and irrigators as well as representative groups highlighted specific situations where investment had been made in infrastructure designed to optimise usage of now obsolete time-of-use tariffs. For example, MDIA Council presented a case study of a cane farm spending over $200,000 to convert a pump from running on diesel to electricity which, if forced onto the current new tariff, would have to revert back to diesel or simply reduce production. In all cases where examples were provided, submissions suggested that there would be increased costs from moving to alternate tariffs ranging from a few percent to around 600%, with the majority reporting increases of more than 100%.

Another potential issue that was raised by irrigators was not only the increase in costs borne directly, but the flow on effect of increased prices to water suppliers that would be passed through in water charges. Canegrowers Isis, Pioneer Canegrowers, QFF and AgForce Qld pointed out that this would result in a hidden increase in costs on top of those quoted in the electricity prices.

Businesses Central Queensland Mining Supplies Razer (CQMS Razer), Dobinsons Spring & Suspension, BWEL and IOR Energy pointed out that moving from Tariff 37 to a demand-based tariff would cause significant increases in their costs and threaten their financial viability. These stakeholders claimed that the nature of their operations meant they cannot smooth their consumption to reduce the demand charge and that they are limited in their ability to adjust to the new tariffs and minimise cost increases.

There was a general theme among those most affected stakeholders that, if transitional arrangements were removed, they would have to seriously consider using alternative forms of energy, such as diesel generators, and disconnecting from the network altogether. Others suggested that there were no options that would ensure their business would survive.

The particular tariffs regularly quoted as causing the most impact were the farming and irrigation Tariffs 62, 65 and 66, and the non-domestic heating time-of-use Tariff 37.

Initially, the timeframes suggested by consumer stakeholders for extended transitional arrangements ranged from at least three years (for example Lower Burdekin Water, Toowoomba Regional Council and SunWater) to 20 years suggested by QFF, PVW and 2PH Farms. Further, QFF suggested that case-specific investigations should be carried out for large rural users to determine necessary timeframes. Others, including BWEL and ASMC, indicated that the timeframe is irrelevant if the final tariff is so high it would put customers out of business anyway.

In response to the Draft Determination, in which the Authority proposed a seven year transitional period based on the depreciable life of irrigation assets, QFF, C & R Consulting, Isis Central Sugar Mill (ICSM) and Pioneer Cane Growers Organisation (PCGO) argued that the effective or economic life of assets was considerably longer than the depreciable life, thus making the suggested timeframe inadequate. Others, including ASMC, BWEL, Canegrowers Isis, Cotton Australia, VM Hillier, G McCarthy, PVW, M & A Stewart and Sucrogen, stated more generally that seven years was not a long enough period without specifically explaining why. However, Australian Industry Group (AIG), Canegrowers, Mackay Sugar, MDIA Council, Toowoomba Regional Council and Ergon Energy supported the seven year transitional period.

Retailers, including AGL, Origin Energy, EnergyAustralia, ERAA and ESAA, held a different view on timeframes, suggesting that customers should be transitioned to cost-reflective tariffs as soon as possible, on the basis that it would be inefficient to continue subsidised tariffs.

Views on the form of transitional arrangements varied widely. The option of moving customers to cost-reflective tariffs then discounting by progressively smaller amounts each year for all customers was supported by CCIQ, which argued that this would provide certainty, reduce complexity of tariff structures and remove the inequity of some businesses being at a competitive disadvantage to others. AGL suggested the opposite, that this approach would increase the number of subsidised customers and should be avoided. The Government suggested that this approach should only be used if the structure of Ergon Energy's updated network tariffs became clear within the delegation period.

Another option for transitioning put forward by AGL was to modify the tariff structure to more closely match the structure of the cost-reflective tariffs, for example reducing multiple block tariffs to one block.

The size of price increases for transitional and obsolete tariffs the Authority proposed in the Draft Determination raised concerns for many stakeholders. Arguments centred around the level of sustained increases over the last five to 13 years. For example, Cotton Australia cited an example of a 350% bill increase since 2000 for a particular cotton grower, and QFF, Canegrowers and MDIA Council suggested that prices for irrigators generally had increased by 90% over the last seven years. Submissions argued that the proposed 2013-14 increase on top of previous increases would force many farms and businesses to close as profit margins are squeezed.

Suggestions for alternative price increases for transitional tariffs ranged from zero (for example, Canegrowers Isis) to CPI (for example, Dobinsons Spring and Suspension) to the increase of the underlying cost-reflective tariff without a secondary escalation (for example, QFF, Canegrowers).

A few submissions appeared to misunderstand the Draft Determination by incorrectly concluding that the proposed tariff increases for 2013-14 would apply to all seven of the proposed transition years. To be clear, the Authority has not set a percentage increase for any year other than 2013-14. In each year that the Authority is delegated the task of setting prices, an analysis of obsolete and cost-reflective tariffs will be undertaken to determine the appropriate movement for that year.

With regard to metering constraints, Energex indicated that there are over 3,000 customers in its distribution area with meters that would require replacement or re-programming in order to move from obsolete to cost-reflective tariffs, and this would take three to six months to complete. Ergon Energy stated that it would be unable to complete the required meter upgrades to move customers from obsolete to new tariffs before 1 July 2013, and would therefore also require a longer transition period. Further, Ergon Energy noted that in cases where a change of tariff requires a new meter, a customer's switchboard may need to be upgraded and that in some cases this may be at considerable cost to the customer.

The Queensland Government, Ergon Energy, Canegrowers, SunWater, and CCIQ pointed out that the many reviews of the electricity industry as a whole and the forthcoming reviews of network tariff structures in Queensland create enough uncertainty to require the extension of transitional arrangements, as it would be unreasonable to set customers on a price path to something that may be restructured in the next few years.

The Authority's proposal in the Draft Determination to allow all customers access to transitional tariffs - including new customers that are excluded - was supported by Ergon Energy, ASMC, Canegrowers, Mackay Sugar, MDIA Council, PVW, QFF and the Government.

Energex, AGL, EnergyAustralia, ERAA and ESAA suggested that new customers should not have access to obsolete tariffs, on the basis that it would create a larger pool of customers that need to be transitioned to cost-reflective tariffs and would create further inefficiency. Cotton Australia also suggested that new customers should not have access to obsolete tariffs on the basis that new investment decisions should be made with the information available at the time.

The Authority's Position

As a general principle, the Authority agrees with retailers that any social welfare concerns arising from implementing the new regulated retail tariffs, or policy aims such as the Four Pillars Economy, would be best addressed through direct assistance by the Government rather than by distorting electricity prices.

However, while the retailers (apart from Ergon Energy) would prefer little or no transition period, the Delegation requires that the Authority consider extending transitional arrangements where customers would face significant price increases. Providing transitional arrangements, particularly in cases where there are sunk investments made by customers on the basis of existing or expected tariff structures, is well documented, and emphasises trade-offs between fairness and economic efficiency and the need to encourage future sunk investments[76].

It is clear from submissions that a large number of customers on the majority of obsolete tariffs would face significant price increases moving to the new cost-reflective tariffs, to the point where some may consider disconnecting from the network and using alternate sources of energy, such as standalone diesel generators, or ceasing operations entirely. Ergon Energy provided the Authority with customer impact assessments for each obsolete tariff (presented below) which confirm claims in submissions about the extent of price impacts for some customers.

Based on material provided in submissions and Ergon Energy’s analysis, the Authority has decided to retain Tariffs 21, 37, 62, 65, 66, 20 (large), 22 (large), 41 (large) and 43 (large) on

[76] See Biggar, D. (2010). "Fairness in Public Utility Regulation: A Theory", Agenda, v. 17(1).

the basis that customers on those tariffs will experience significant price impacts moving to the new tariffs (the Authority's analysis and findings for each tariff are presented below).

Having determined which tariffs are to be retained, it is necessary to decide how long they will be retained for, how much the charges for each tariff will be increased by during the transitioning period, and which customers will have access to the tariffs.

As suggested in several submissions, a key difficulty in determining transitional arrangements is the uncertainty over how much the level and structure of notified prices may have to change over the next several years. This is mainly because the underlying network charges, which comprise around 50% of the final retail price, may be influenced by a number of recent and ongoing reviews. It is not inconceivable that the level and structure of network charges could change to such an extent that any price path set this year may over- or under-shoot the eventual cost-reflective tariffs for the majority of customers once these reviews have been completed and implemented. Some examples of recent and ongoing reviews with a network focus include:

(a) AEMC's update of NER to improve the strength and capacity of the AER to determine network price increases;

(b) AEMC's Transmission Frameworks Review, due March 2013 with a policy response expected June 2013;

(c) AEMC's Review of the Distribution Reliability Outcomes and Standards due around mid-2013;

(d) the Queensland Independent Review Panel on network costs, provided to the Queensland Government in December 2012;

(e) AER's development of "Better Regulation" guidelines and consulting across all areas it regulates, to be finalised by November 2013;

(f) Ergon Energy's review of its network tariff strategy, with consultation occurring in 2013-14 and implementation of new network tariffs expected to begin from 2014-15; and

(g) Productivity Commission's comprehensive review of network regulation benchmarking, provided to the Commonwealth Government in April 2013.

In addition, there are a number of broader energy market reviews that may influence the level and structure of electricity prices in the next several years, including the Australian Government Energy White Paper, which has been endorsed by the Council of Australian Governments (COAG), the AEMC's Power of Choice review, and the Queensland Government's Inter-Departmental Committee on Electricity Sector Reform, which is an input to the development of a 30-year electricity plan by the Government, due to be released around mid to late 2013.

How Much to Escalate Obsolete Tariffs

While all of these reviews create uncertainty in relation to the level and structure of notified prices, it is unlikely that customers facing significant bill impacts will avoid these entirely as notified prices evolve over the next several years. This is mainly because the charges associated with the obsolete tariffs they are on are so favourable, for example, because they include very low charges or do not include demand charges. In addition, the underlying costs of supply are not likely to fall in the foreseeable future.

As a result, the Authority considers that as a minimum first step, charges for all obsolete tariffs should be increased sufficient to reflect increases in the underlying costs of supply, as opposed to no increase, or an increase in line with CPI as suggested in submissions. To do otherwise would mean that obsolete tariffs would fall further below cost and increase the size of the transitioning task to be managed in future years. The size of the underlying cost increase would be the same percentage increase that customers would experience if they were on the cost-reflective tariffs that they would move to in the absence of transitional arrangements.

Table 6.3 presents the increases in annual bills for typical customers (according to data provided by Ergon Energy) on each of the cost-reflective tariffs for 2013-14. Bill impacts can vary significantly depending on each individual customer's level and pattern of consumption. However, in order to avoid unworkably complex arrangements, it is necessary to use an approach that should be appropriate for the majority of customers.

Tariffs 47 and 48 are omitted because there is only a very small number of customers on these tariffs, which may skew the results.

Table 6.3: Percentage Increase for Cost Reflective Tariffs[a]

Retail Tariff	*Median Consumption kWh*	*Median Demand kW*	*2012-13 Annual Bill $*	*2013-14 Annual Bill $*	*Difference %*
Energex Network Tariffs					
Tariff 20	5,375		1,615	1,896	17.4%
Tariff 22[b]	15,250		3,638	4,202	15.5%
Ergon Energy Network Tariffs					
Tariff 44	203,157	54	48,306	54,704	13.2%
Tariff 45	785,260	206	171,770	194,878	13.5%
Tariff 46	2,422,237	518	467,992	529,154	13.1%

a. Consumption data provided by Ergon Energy and Energex.
b. Assumes 48%/52% peak/off-peak split, advised by Ergon Energy.

Table 6.4 shows the alignment of obsolete tariffs to the cost-reflective tariffs and the escalation rates the Authority has applied to reflect underlying cost increases.

While the analysis presented in Table 6.3 suggests larger impacts for Tariff 20, the Authority is mindful that the alignment of obsolete tariffs to Tariff 20 or 22 is not always clear cut. For example, last year Tariff 37 was aligned with Tariff 22 on advice from Energex whereas this year Ergon Energy has advised that Tariff 37 aligns better with Tariff 20. In addition, the sizes of the impacts shown for Tariff 22 are sensitive to the assumed ratio of peak to off-peak consumption. In light of these uncertainties, the Authority has decided to take the simple average of the increases for Tariffs 20 and 22 of 16.45%, rounded to 16%, and to apply this to the obsolete tariffs shown in Table 6.4. This has increased from 14% since the Draft Determination due to changes in both the network and retail elements of the cost-reflective tariffs.

The average for Tariffs 44, 45 and 46 is 13.3%, which the Authority has rounded to 13% and applied to obsolete tariffs that align with Tariffs 44 to 48, as shown in Table 6.4. This has increased from 10% since the Draft Determination due to changes in both the network and retail elements of the cost-reflective tariffs[77].

Table 6.4: Alignment of Cost-Reflective & Obsolete Tariffs and Underlying Cost Increases

Cost-Reflective Tariff	*Obsolete Tariffs*	*Escalation to Reflect Increase in Underlying Costs*
Tariff 20	Tariffs 21, 37, 66	16%
Tariff 22	Tariffs 62, 63, 64, 65	16%
Tariffs 44-48[a]	Tariffs 20 (large), 22 (large), 41 (large), 43 (large), 53 (large)	13%

a. The most appropriate of these tariffs depends on the customer's kW demand and voltage requirements.

While the escalation factors presented in Table 6.4 will maintain the gap to cost-reflectivity in percentage terms, in dollar terms the gaps will continue to grow. This is simply because any given percentage increase in a higher (cost-reflective) bill will be greater in dollar terms than the same percentage increase in a smaller (obsolete tariff) bill. For example, if two bills of $1,000 and $2,000 both increase by 10% to $1,100 and $2,200 respectively, the dollar difference between them increases from $1,000 to $1,100.

In order to limit the growth in this gap, which will mitigate the ultimate transition to cost-reflective tariffs that customers will have to make and the cost to taxpayers of subsidising obsolete tariffs, the Authority has decided to further increase the charges for obsolete tariffs based on an assessment (below) of how far customers are already subsidised relative to their cost-reflective price. For these reasons, the Authority disagrees with some stakeholders that escalating prices by more than underlying cost increases is "price gouging" (M & A Stewart) or "artificial, arbitrary and unnecessary" (Canegrowers). Based on the analysis of how far customers are from cost-reflectivity, the obsolete tariffs can be split into three broad groups: those with a majority of customers subsidised by 50% or more; those with a majority of customers subsidised between 50% and 10% and those with a majority of customers subsidised by less than 10%. The further from cost-reflectivity, the higher the additional increase will be.

Given uncertainties about future notified prices, the Authority considers that the objective of transitioning for the coming year should be about limiting the extent to which customers on obsolete tariffs become increasingly subsidised as underlying costs continue to rise and less focussed on moving customers towards their cost-reflective prices. On this basis the Authority considers that price increases for these customers should be capped at an upper limit of 1.5 times the underlying cost increases for customers whose prices are subsidised by 50% or more below the cost-reflective price, 1.25 times underlying costs for customers whose prices are subsidised by between 50% and 10%, and 1.1 times underlying costs for customers whose prices are subsidised by less than 10%. These increases will reduce how far customers' bills are below cost-reflective levels in percentage terms, and will limit how far below cost customers are in dollar terms, although the dollar gap will still grow, particularly for customers who face very large increases in moving to cost-reflective tariffs.

For example, in most circumstances, for a customer who receives a subsidy of more than 50%, increasing prices by 1.5 times the underlying cost increase (if that increase remains at

[77] The increases in cost-reflective tariffs calculated in the Draft Determination for Tariffs 44, 45 and 46 were incorrect due to a calculation error. The reported average 10% increase should have been 12%. As a result, the true increase from the Draft Determination to this Final Determination is 12% to 14%.

the 2013-14 level) would still not achieve cost-reflective prices within seven years. Similarly, in most circumstances, for a customer who receives a subsidy of between 50% and 10%, increasing prices by 1.25 times the underlying cost increase (if that increase remains at the 2013-14 level) would not achieve cost-reflective prices within seven years.

It is also worth noting that applying these escalation factors to lower increases in underlying costs than those expected in 2013-14 would further extend how long it takes to achieve cost-reflective prices. Similarly, applying a lower escalation factor to the same underlying increases as those in 2013-14 also extends how long it takes to achieve cost-reflective prices.

For these reasons the Authority considers it would not be prudent to set price increases lower than the increases presented in Table 6.5, as suggested in submissions. The further behind cost-reflectivity prices become this year, the more difficult it will be to bridge the gap in future years where underlying cost increases are likely to be lower[78]. In years of lower underlying cost increases the escalation factor would need to be higher to prevent the prices drifting further apart.

It is also important to note that many thousands of customers on these tariffs would be better off on cost-reflective tariffs right now. Over the seven year transitional period this number will increase as those on the lower end of the spectrum of impacts gradually move to cost-reflective tariffs.

Transition Period

The final task is to determine an appropriate period over which to transition prices. In this context, as described above, for many customers on obsolete tariffs the gap to cost-reflectivity is so large that the transitional increases presented in Table 6.5 would not close it for a very long time. As a result, the length of the transition period is less about increasing obsolete tariffs to cost-reflective levels and more about allowing time for customers to adapt to new tariffs and recoup some of the value of past investments made to suit the levels and structures of charges for obsolete tariffs.

Stakeholders' suggestions on the length of the transition period varied from three to 20 years. Sucrogen and Queensland Cotton suggested that obsolete tariffs should be retained until all customers have moved of their own volition to cost-reflective tariffs. However, the Authority does not consider that leaving obsolete tariffs in place for an indefinite period would be appropriate given the emphasis in the Electricity Act on cost-reflective pricing and competition.

In response to the consultation papers, Canegrowers suggested basing the transitional period on the number of years stated in the Australian Taxation Office (ATO) depreciation schedule for irrigation pumps (12 years), on the basis that farmers require a return over the equipment's depreciable life. Using the depreciable life as the basis for the transitional period was supported in some submissions received in response to the Draft Determination. However, others argued that effective life is longer than depreciable life, as noted above. The methodology used by the ATO to calculate the depreciable life of assets appears to align with what could be regarded as effective life, as it takes account (amongst other things) of the way the asset is used by the industry, actual retention periods, economic analysis that indicates the period it is intended for use, and manufacturer specifications[79]. Importantly, the ATO’s definition of the effective life of an asset does not extend beyond its economic life

[78] AEMC, Electricity Price Trends Final Report, 22 March 2013, http://www.aemc.gov.au/media/docs/ELECTRICITY-PRICE-TRENDS-FINAL-REPORT-609e9250-31cb-4a22-8a79-60da9348d809-0.PDF

[79] Australian Taxation Office, Taxation Ruling TR 2012/2, Income tax: effective life of depreciating assets (applicable from 1 July 2012), http://law.ato.gov.au/atolaw/view.htm?docid=TXR/TR20122/NAT/ATO/00001

when, for example, inefficiently costly levels of maintenance may be required to keep the asset running.

For these reasons, the Authority considers depreciable life remains a reasonable basis for setting an appropriate transitioning period for obsolete tariffs.

The Authority notes the ATO depreciation schedule indicates that other small business assets that might rely on electricity consumption generally have lives up to 10 years. The ATO depreciation schedule also suggests longer lives for major manufacturing assets, such as electric arc furnaces, of around 10 to 15 years. However, as the majority of submissions relate to investment in farming and irrigation infrastructure, this suggests that 12 years might be an appropriate starting point. Further, there are several reasons why the Authority considers that a shorter transition period would be more appropriate.

First, the new cost-reflective tariffs that customers are to transition to have been in place since 1 July 2012, and the prospect of changes to notified pricing were flagged before that. Also, three of the obsolete tariffs were already declared obsolete prior to 1 July 2012, which will have prevented new customers accessing those three tariffs (or investing in assets to suit those tariffs) since they were made obsolete. For example, Tariff 37, which is likely to be used by customers with longer-lived assets, has been obsolete since 2007. Even where tariffs were not made obsolete until 1 July 2012, the overwhelming majority of submissions suggested that customers had been supplied on these tariffs for many years, in some cases many decades. While some of these customers may have recently replaced or repaired individual assets, it is likely that their total stock of assets would have already been at least partly, if not totally, depreciated.

Providing customers with sufficient time to recoup their investments in assets and adjust their consumption to suit the new tariffs must be weighed against the requirement that, eventually, customers must move to new cost-reflective tariffs. As noted previously, taxpayers continue to subsidise affected electricity customers for as long as transitional arrangements remain in place.

Based on these considerations, the Authority has decided to retain obsolete tariffs (except Tariffs 41 (large) and 43 (large) for the reasons discussed below) for a period of seven years. While this is shorter than proposed by some stakeholders, it is significantly longer than the transitional period proposed in a number of submissions (including Lower Burdekin Water, SunWater - three years - and BRIG - five years), and was supported by the Queensland Government, AIG, Canegrowers, Ergon Energy, Mackay Sugar, MDIA Council and Toowoomba Regional Council in response to the Draft Determination.

The transitioning period will be reviewed in future years, but only to ensure that any changes to network tariff structures have not changed the outcomes to such an extent that transitional arrangements are no longer necessary. The Authority assumes this period will provide more than enough time for any metering changes required to implement cost-reflective tariffs.

Customer Impacts

Ergon Energy has provided information on customer impacts from moving to cost-reflective tariffs. Most customers on obsolete tariffs are in the Ergon Energy distribution area, as the majority apply to large customers (which are not able to access notified prices in the Energex area) and apply to farmers/irrigators which are more numerous in Ergon Energy's area.

The decisions on whether to retain obsolete tariffs, how much to increase them by and for how long (discussed above), are based on the number of customers accessing each tariff, the impact to customers of moving to an alternate cost-reflective tariff, the size of the gap between the obsolete and cost-reflective tariff, and practical impediments to moving to a cost-reflective tariff.

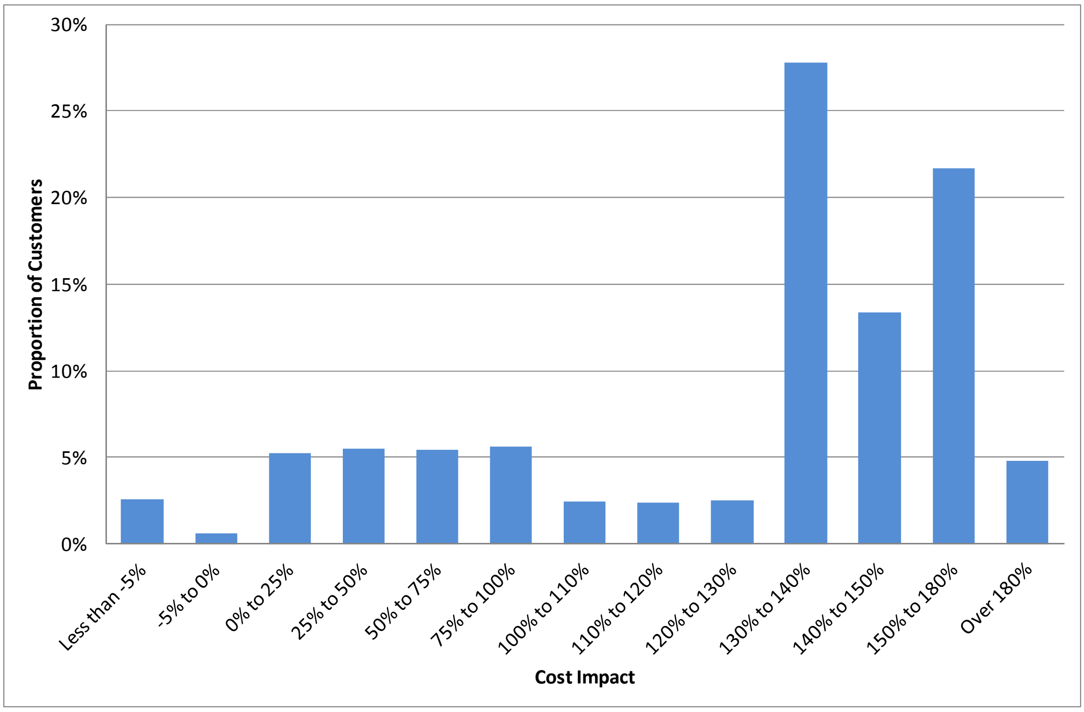
The assessment of impacts centres on the alignment of tariffs indicated in Table 6.4, which shows to which cost-reflective tariff the majority of customers on each obsolete tariff will eventually move.

Note that the following analysis is based on customers moving from their current 2012-13 prices to 2013-14 cost-reflective prices (as presented in the Draft Determination), and therefore shows larger price impacts than indicated in the Draft Determination, which, due to time constraints, only showed price impacts of moving to 2012-13 cost-reflective prices. There has also been a slight change to the methodology used by Ergon Energy to demonstrate the tariff impacts in cases where there is more than one tariff per customer, to try and better reflect the customer outcomes. In most cases this causes a negligible impact except for Tariff 20 (large) and large customers on Tariff 37, as explained in the relevant sections below.

Obsolete Tariffs 21, 37 and 66

Obsolete Tariffs 21, 37 and 66 align with the cost-reflective Tariff 20. Figures 6.3 to 6.5 show the impacts of customers moving to Tariff 20.

Figure 6.3: Change in Electricity Bills for Customers on Tariff 21



Source: Ergon Energy

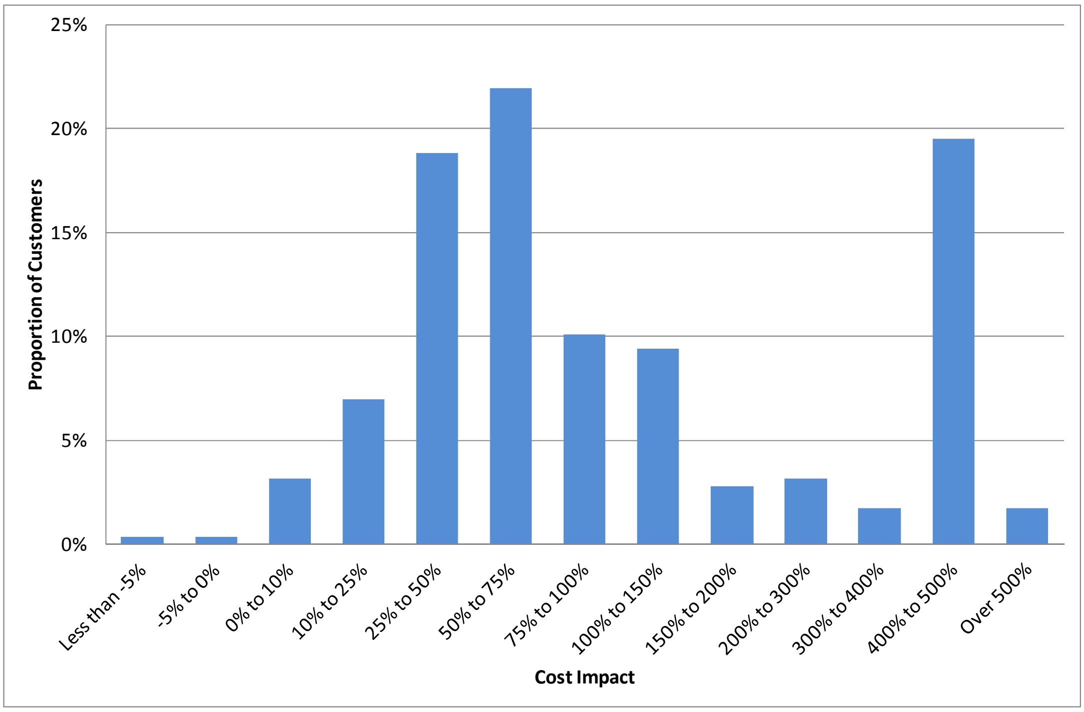
Tariff 21 is a business general supply tariff that was made obsolete in 2012 and is available only to customers that were taking supply under Tariff 21 at 30 June 2012. There are many thousands of customers on this tariff.

The majority of customers on Tariff 21 would experience over 100% price increases moving to the cost-reflective Tariff 20. This is because they would face a fixed charge that is higher than the minimum daily usage charge under Tariff 21, the effect of which outweighs the lower consumption charge under Tariff 20 at the very low levels of consumption that are typical of customers on Tariff 21.

While significant in percentage terms, the dollar impacts of moving to Tariff 20 are relatively low because of these very low consumption levels. The Authority understands that focusing on dollar impacts may be misleading because some customers have multiple meters. Despite this, the obsolescence of Tariff 21 was not raised as an issue in submissions, nor was metering specifically raised as a barrier to shifting customers to Tariff 20.

However, due to the large number of customers on Tariff 21 and the significant percentage increases customers would experience moving to the cost-reflective Tariff 20, the Authority has decided to retain Tariff 21 for seven years, with prices escalated by 24% in 2013-14 (1.5 times the 16% underlying cost increase indicated in Table 6.4).

Figure 6.4: Change in Electricity Bills for Small Customers on Tariff 37



Source: Ergon Energy

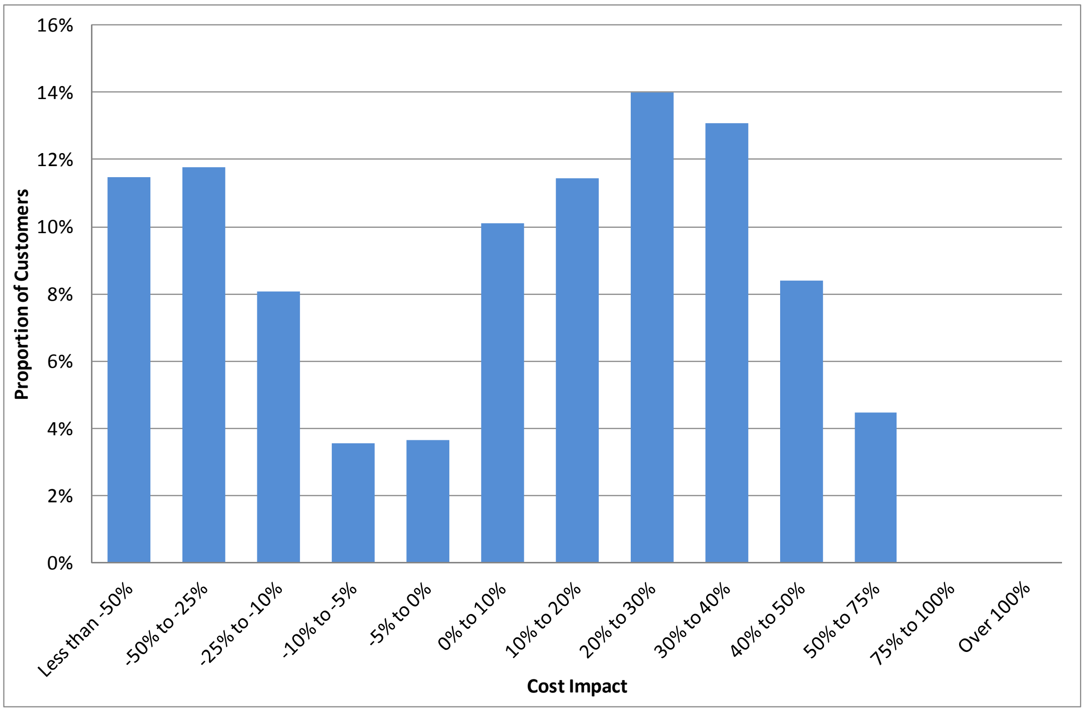
Tariff 37 is for non-domestic heating loads and has been declared obsolescent since 2007-08. It is available only to customers that were taking supply under Tariff 37 at 30 June 2007. There are a few hundred customers on this tariff.

Price increases for small customers on Tariff 37 arise because these customers enjoy low off-peak charges for almost all of the standard 8am to 5pm workday whereas these hours are charged at a higher rate under Tariff 20.

In addition to these impacts for small customers, there is also a metering issue for transitioning large customers on Tariff 37 to one of Tariffs 44 to 48 which have demand charges, with both Energex and Ergon Energy indicating the required metering would not be in place for these customers by 1 July 2013.

Given the potentially drastic price impact for small customers on Tariff 37 and the continuing metering constraints affecting large customers, the Authority has decided to retain Tariff 37 for seven years, with prices escalated by 20% (1.25 times the 16% underlying cost increase indicated in Table 6.4). This is less than the 21% proposed in the Draft Determination because the updated analysis provided by Ergon Energy shows that the majority of customers would face a price increase of between 10% - 100% rather than more than 100% as indicated in the Draft Determination.

Figure 6.5: Change in Electricity Bills for Small Customers on Tariff 66



Source: Ergon Energy

Tariff 66 is a flat irrigation tariff declared obsolete in 2012-13, which is available only to customers that were taking supply under Tariff 66 at 30 June 2012. There are a few thousand customers using this tariff.

Around 40% of the customers on Tariff 66 would actually be better off on the cost-reflective Tariff 20, due to the lower daily charge and absence of a capacity charge in Tariff 20, which offsets the higher variable rate. Other customers would face increases of up to 75%. Metering changes would not be required for small customers to move to another flat rate tariff.

These impacts, as well as those for large customers (see below), support retention of Tariff 66. In addition, there are some continuing metering constraints associated with moving large customers off Tariff 66. For these reasons, the Authority has decided to retain Tariff 66 for small and large customers for seven years, with prices to increase by 20% in 2013-14 (1.25 times the 16% underlying cost increase indicated in Table 6.4). Since Tariff 66 is to be retained for large customers, small customers will also be able to remain on Tariff 66.

Obsolete Tariffs 62, 63, 64 and 65

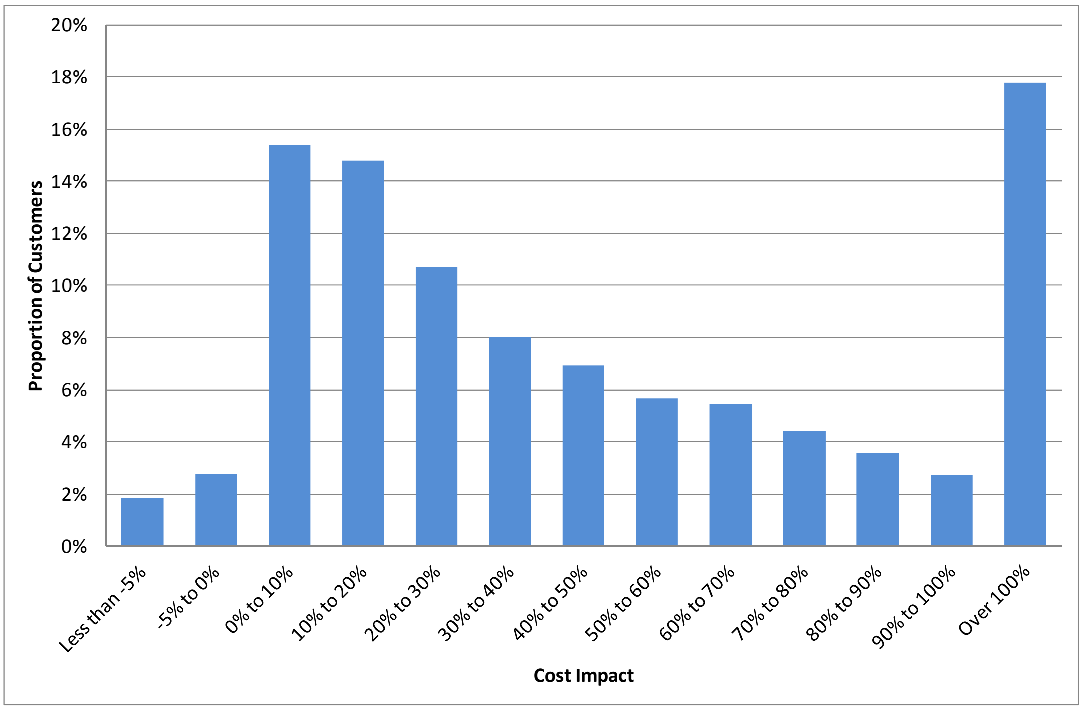
Tariffs 62 and 65 are time-of-use tariffs for farming and irrigation customers and were declared obsolete in 2012-13. They are available only to customers that were taking supply under Tariffs 62 and 65 at 30 June 2012. There are many thousands of customers using these tariffs.

Tariffs 63 and 64 are time-of-use tariffs for farming and irrigation customers and have been obsolete since 1995. They are available only to customers that were taking supply under Tariffs 63 or 64 at 26 March 1995.

The majority of customers on obsolete Tariffs 62, 63, 64 and 65 will move to the cost-reflective Tariff 22.

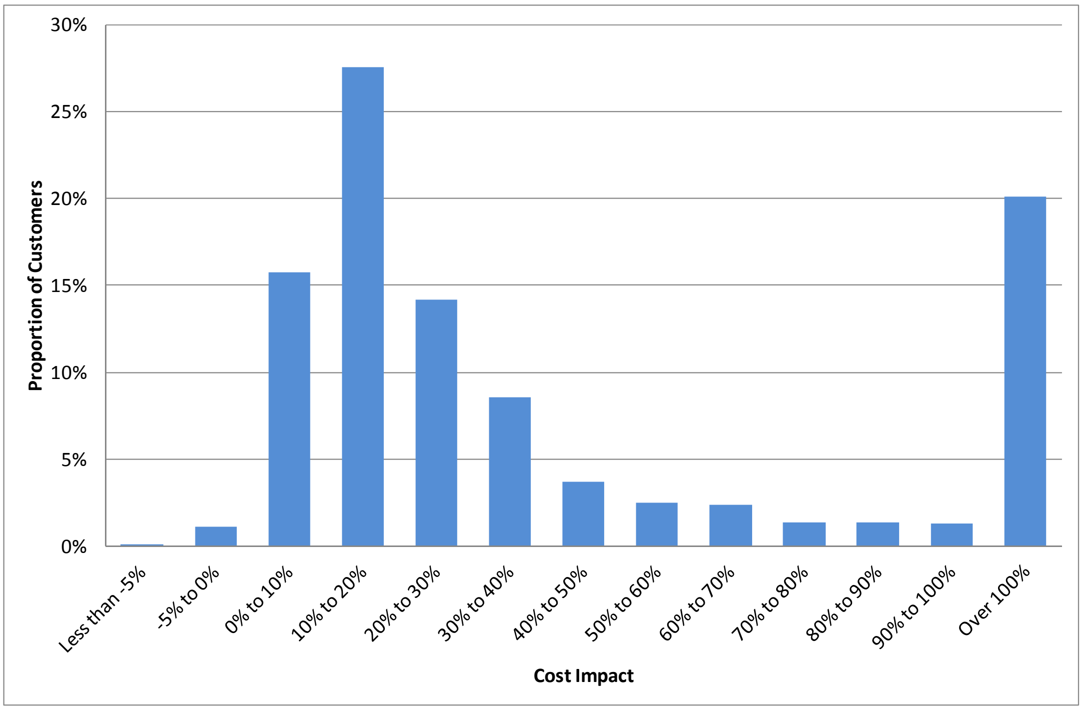
As there are very few customers on Tariffs 63 and 64 and they are similar to Tariffs 62 and 65, Ergon Energy included these customers in the customer impact Figures for Tariffs 62 and 65 respectively, presented in Figures 6.6 and 6.7.

Figure 6.6: Change in Electricity Bills for Small Customers on Tariffs 62 & 63



Source: Ergon Energy

Figure 6.7: Change in Electricity Bills for Small Customers on Tariffs 64 & 65



Source: Ergon Energy

Figures 6.6 and 6.7 indicate that there is a wide range of potential impacts for customers moving from obsolete Tariffs 62 to 65, from small price decreases to significant increases of over 100%, although the majority of increases are below 100%. Increases for customers on these tariffs are due mainly to the higher off-peak rate in Tariff 22 relative to those available under Tariffs 62 to 65.

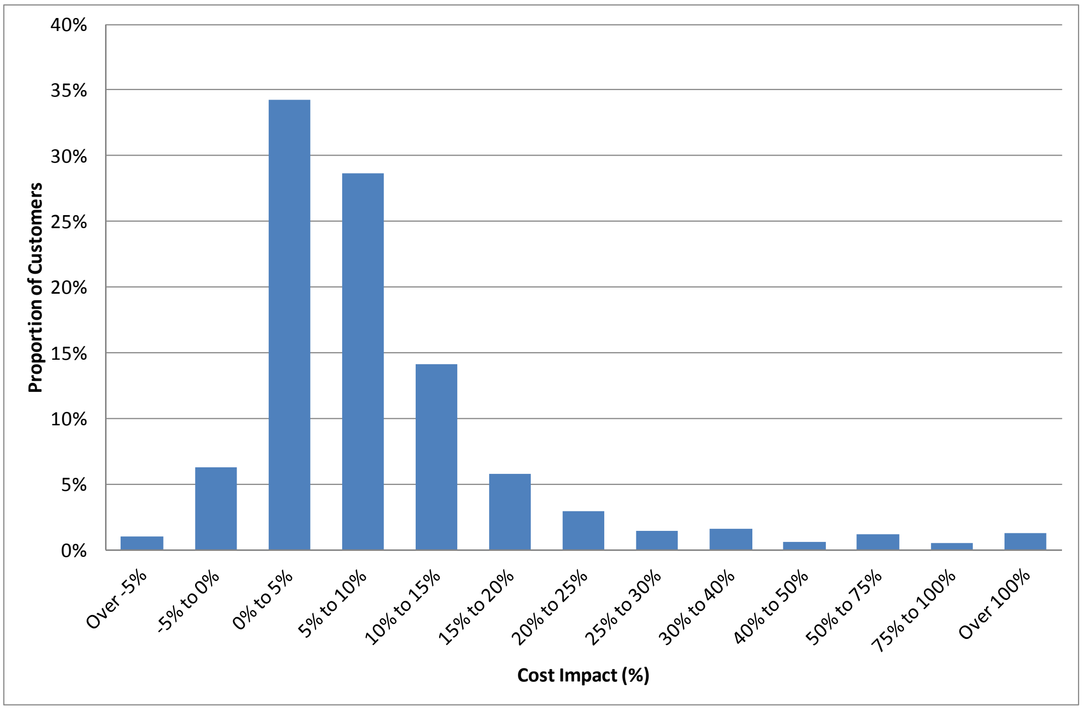
The Authority has decided to remove obsolete Tariffs 63 and 64, given their similarity to Tariffs 62 and 65 respectively and the small number of customers on those tariffs. Affected customers will be transferred to either Tariff 62 or 65 (and benefit from the transitioning arrangements for those two tariffs). Canegrowers Isis indicated that irrigators typically consume much larger volumes than the levels at which customers would be better off on Tariffs 63 and 64 (rather than being on Tariffs 62 or 65). Ergon Energy supported removing Tariffs 63 and 64 and shifting these customers to Tariffs 62 and 65 respectively. Removal of these tariffs was not raised as a concern in any submissions.

Given the significant impact to customers of moving from Tariffs 62 and 65 to cost-reflective tariffs, the Authority has decided to retain Tariffs 62 and 65 for seven years, with prices escalated by 20% for 2013-14 (1.25 times the 16% underlying cost increase indicated in Table 6.4).

Obsolete Tariffs for Large Customers

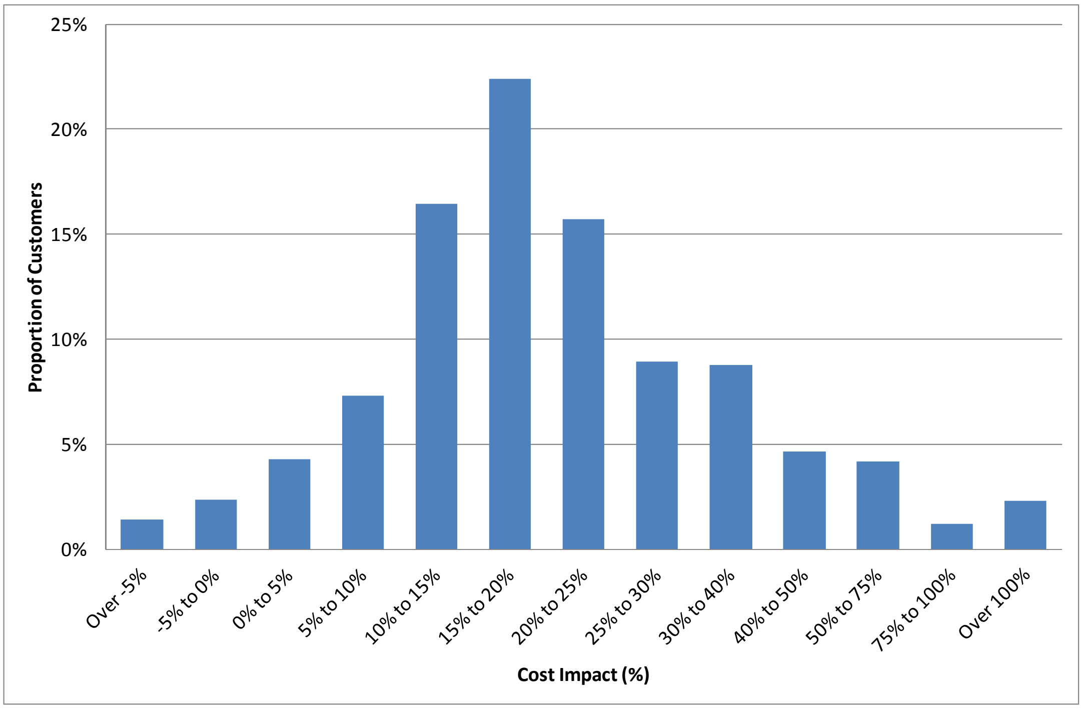
Tariffs 20 (large), 22 (large), 41 (large), 43 (large) and 53 (large) align with cost-reflective Tariffs 44 to 48 which are based on Ergon Energy network tariffs. Figures 6.8 to 6.12 show the likely impacts for customers moving from these obsolete tariffs to the most appropriate of these cost-reflective tariffs. In most cases Ergon Energy used an assumed demand profile as actual data was not available. This could lead to over- or underestimation of bill impacts due to the sensitivity of bills to changes in maximum demand.

Figure 6.8: Change in Electricity Bills for Customers on Tariff 20 (Large)



Source: Ergon Energy

Figure 6.9: Change in Electricity Bills for Customers on Tariff 22 (Large)



Source: Ergon Energy

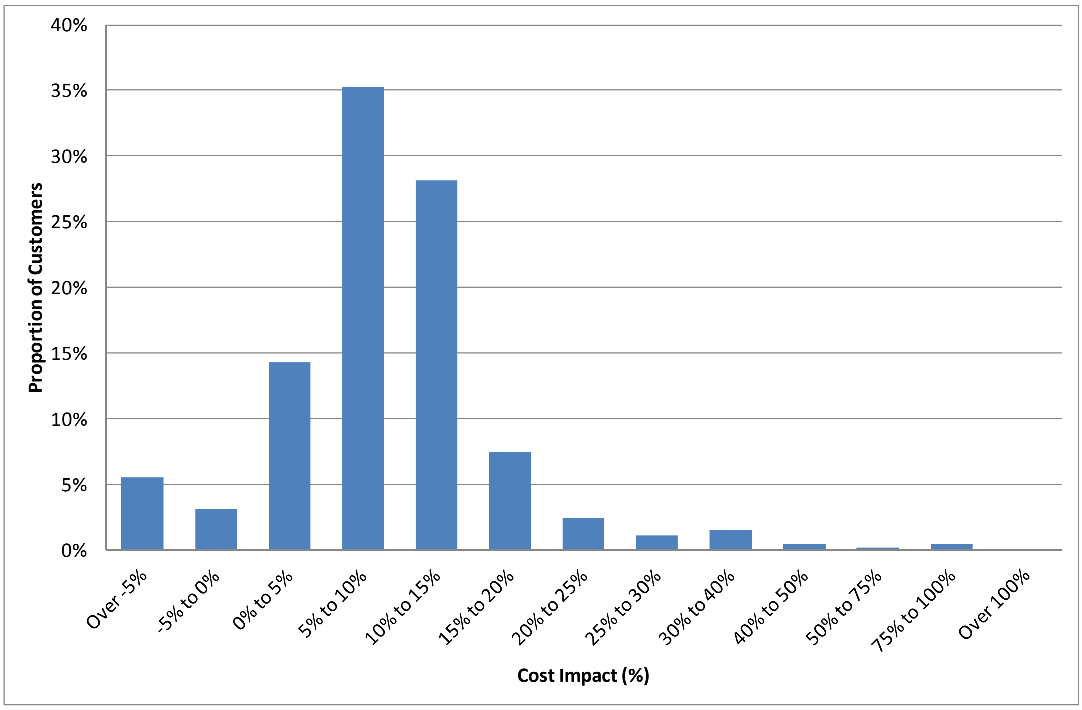
Tariffs 20 and 22 for large customers were made obsolete in 2012-13, and are only available to large business customers in Ergon Energy's network area that were taking supply under Tariffs 20 and 22 as at 30 June 2012. There are a few thousand customers using these tariffs.

Figure 6.8 shows the majority of large customers on Tariff 20 would face increases of up to 10% and that very few customers would experience significant increases. Figure 6.9 shows a wider range of impacts for customers on Tariff 22, with the bulk experiencing price increases between 10% and 100%. The cost-reflective tariffs for large customers (Tariffs 44 to 48) include demand charges, whereas the obsolete tariffs do not, and the fixed charges are significantly higher. The impact on individual customers will depend on whether the costs from the much higher fixed charges and demand charges outweigh the savings customers could make with the lower variable charges in the cost-reflective tariffs.

Ergon Energy has confirmed that metering required for customers to move to the cost-reflective tariffs have still not been addressed and would not be in place for all customers by 1 July 2013.

Considering the level of increases and the number of affected customers, as well as the continuing metering constraints to shifting customers to cost-reflective tariffs, the Authority has decided to retain Tariffs 20 (large) and 22 (large) for seven years, with prices escalated by 14.3% for Tariff 20 and 16.3% for Tariff 22 for 2013-14 (1.1 and 1.25 times the 13% underlying cost increase indicated in Table 6.4).

Figure 6.10: Change in Electricity Bills for Customers on Tariff 41 (Large)



Source: Ergon Energy

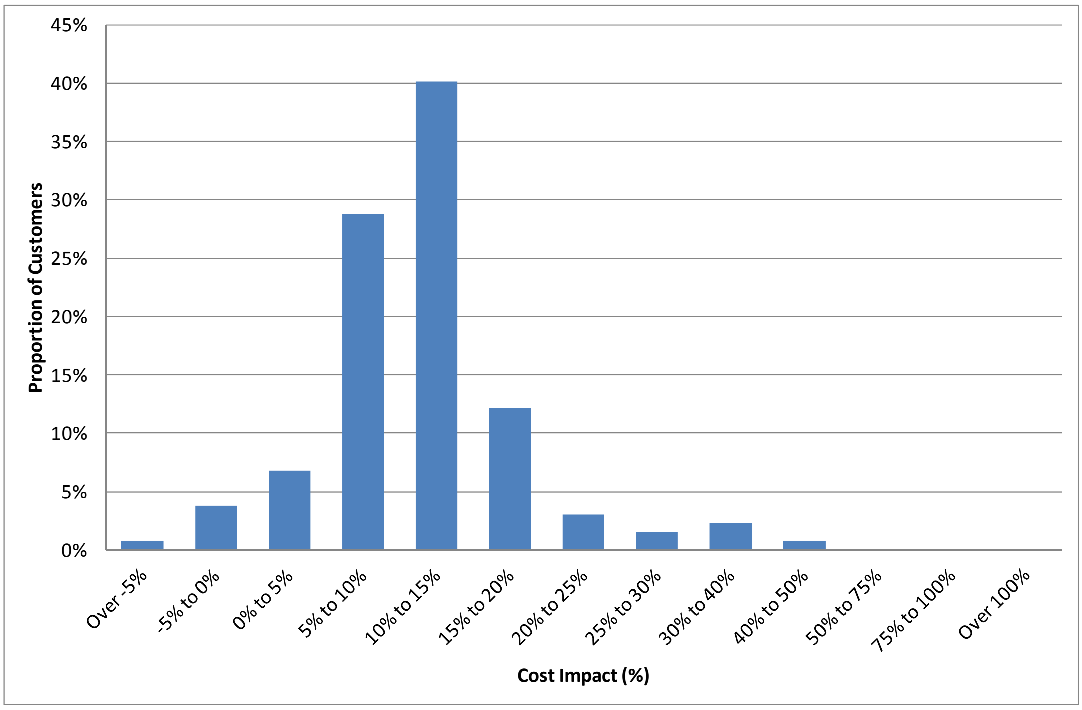
Obsolete Tariff 41 (large) is for large business, low voltage, general supply and was declared obsolete in 2012-13. It is available only to large business customers in Ergon Energy's network area that were taking supply under Tariff 41 (large) at 30 June 2012. There are a few hundred customers on this tariff.

Just under 60% of customers would be better off or experience increases of up to 10% moving to the cost-reflective tariffs, because the lower demand charges in the cost-reflective tariffs would offset the higher variable and daily fixed charges. Of those customers that would experience an increase, around 40% would see a rise of 10% or more, with dollar values up to $100,000. Despite this, no submissions suggested that the removal of Tariff 41 (large) would cause financial distress to customers. Metering has not been raised as a constraint for this tariff as the structure is already the same as that of the cost-reflective tariffs.

As some of the potential increases, while only affecting a small number of customers, are substantial in dollar terms, the Authority has decided to retain Tariff 41 (large) for two years instead of only one year as proposed in the Draft Determination, to align with the implementation of Ergon Energy's network tariff strategy and to avoid the disruption to customers of having to move to an interim retail tariff. Prices will be escalated by 14.3% for 2013-14 (1.1 times the 13% underlying cost increase indicated in Table 6.4).

The Authority expects that those Tariff 41 (large) customers adversely impacted would begin to make adjustments necessary to minimise the impact of moving to a cost-reflective tariff as soon as possible. Alternatively, after two years the worst affected customers could move to other (retained) obsolete tariffs for large customers subject to eligibility and metering requirements.

Figure 6.11: Change in Electricity Bills for Customers on Tariff 43 (Large)



Source: Ergon Energy

Tariff 43 (large) was declared obsolete in 2012-13 and is only available to large business customers in Ergon Energy's network area that were taking supply under Tariff 43 (large) as at 30 June 2012. There were fewer than 200 customers on this tariff as at 31 October 2012.

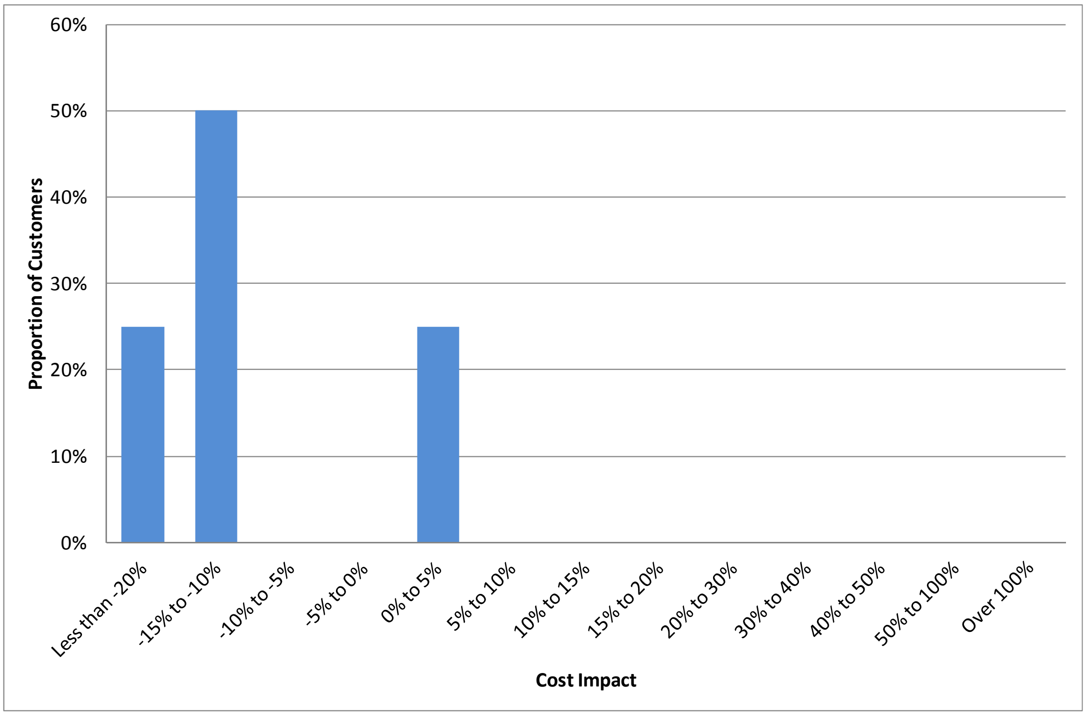
Figure 6.11 shows that most customers would experience a 5% - 15% increase on their appropriate cost-reflective tariff. The maximum increase for the remaining customers would be 50%. Like Tariff 41 (large), the structure already has a demand charge, but customer impacts depend on the time-of-use profile of each customer as there is no off-peak charge in the cost-reflective alternatives. Only three submissions suggested that Tariff 43 (large) would cause financial distress to customers if it was removed.

In terms of billing and metering, the tariff structure already includes a demand element and while the consumption has a peak and off-peak component, the Authority has not been made aware of any specific metering constraints because of this.

However, some of the increases, while only affecting a small number of customers, are substantial in dollar terms. On this basis, the Authority has decided to retain Tariff 43 (large) with prices escalated by 14.3% for 2013-14 (1.1 times[80] the 13% underlying cost increase indicated in Table 6.4). As with Tariff 41 (large), Tariff 43 (large) will now be retained for two years to align with the implementation of Ergon Energy's network tariff strategy.

The Authority expects that those Tariff 43 (large) customers adversely impacted would begin to make adjustments necessary to minimise the impact of moving tariff as soon as possible. Alternatively, after two years the worst affected customers could move to other (retained) obsolete tariffs for large customers, subject to eligibility and metering requirements.

Figure 6.12: Change in Electricity Bills for Customers on Tariff 53 (Large)



Source: Ergon Energy

Tariff 53 (large) was declared obsolete in 2012-13, and is only available to large business customers in Ergon Energy's distribution area that were taking supply under Tariff 53 (large) as at 30 June 2012. EEQ had four customers on this tariff as at 31 October 2012. Note that this chart has not been updated from the Draft Determination as steps have already been taken to move these customers to an appropriate cost-reflective tariff.

Figure 6.12 shows that three of the four customers on this tariff would be better off on their appropriate cost-reflective tariff, while the fourth would face an increase of up to 5%. The decreases are due to the lower demand charges in the cost-reflective tariffs that offset the slightly higher flat variable rates. No submissions suggested the removal of Tariff 53 (large) would cause financial distress to customers. The Authority has not been made aware of any specific metering constraints thus metering should not need to be changed.

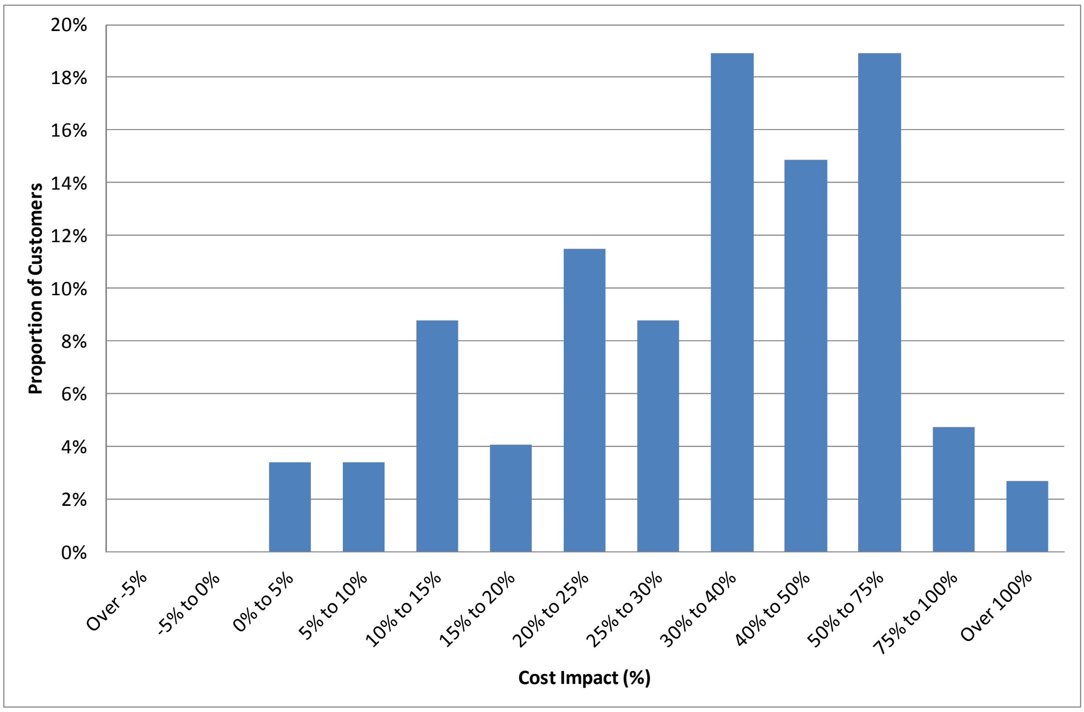
Given the few customers on Tariff 53 (large) and the relatively small negative impact affecting only one of these, the Authority has decided to remove Tariff 53 (large) from 1 July 2013. The four customers on Tariff 53 (large) will be required to shift to a cost-reflective tariff or another obsolete tariff, subject to eligibility and metering requirements.

[80] While the majority of impacts falling between 10% - 100% would indicate using a multiple of 1.25, the Authority has applied a multiple of only 1.1 as most increases are close to 10%.

Other Large Customers

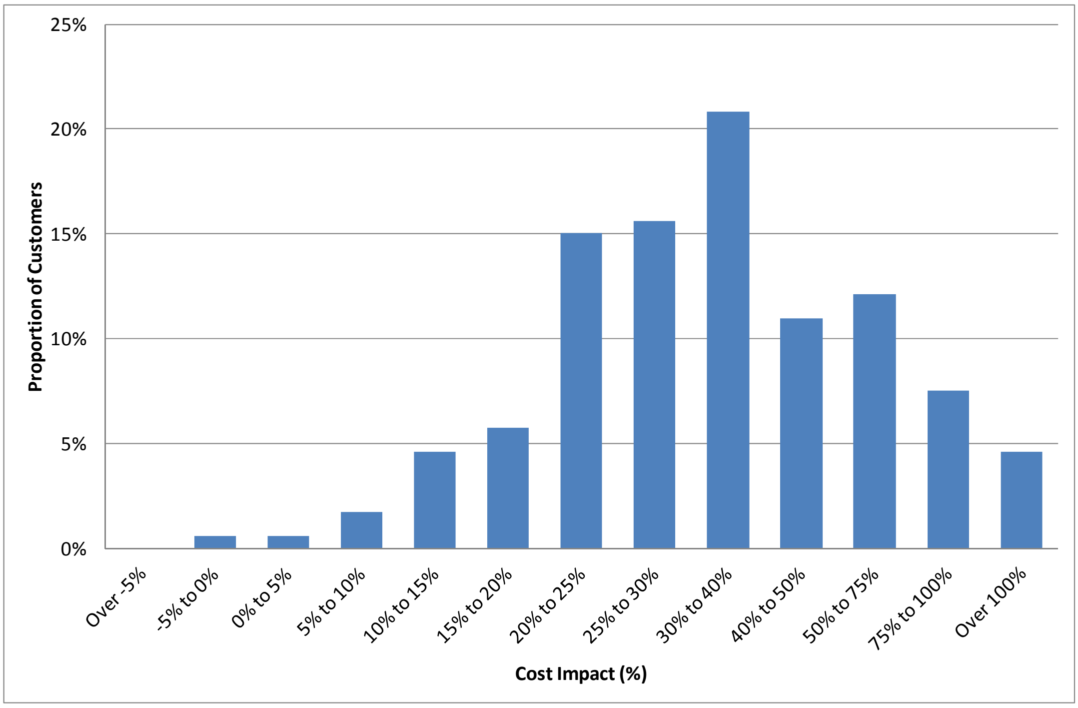
Some of Ergon Energy's large customers are on what are essentially small customer Tariffs 37, 62, 65 and 66. These large customers will be required to shift to one of Tariffs 44 to 48 for large customers (or whatever tariffs are available to large customers following Ergon Energy's review of its network tariffs and pricing), rather than the cost-reflective tariffs for small customers that most (small) customers on Tariffs 37, 62, 65 and 66 will shift to as discussed above. As cost-reflective tariffs for large customers include demand charges, customer impacts for large customers on these tariffs can be significantly different to those experienced by small customers. The Authority has therefore included an assessment of impacts for large customers on these tariffs in determining transitional arrangements.

Figure 6.13: Change in Electricity Bills for Large Customers on Tariff 37



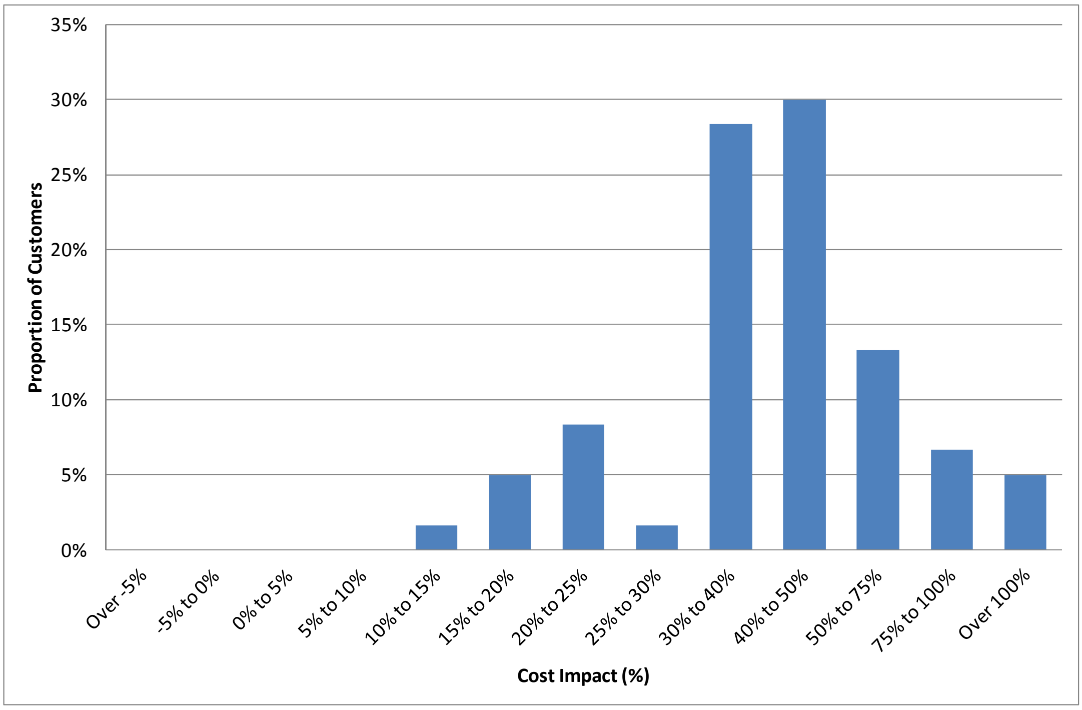
Source: Ergon Energy

Figure 6.14: Change in Electricity Bills for Large Customers on Tariff 62



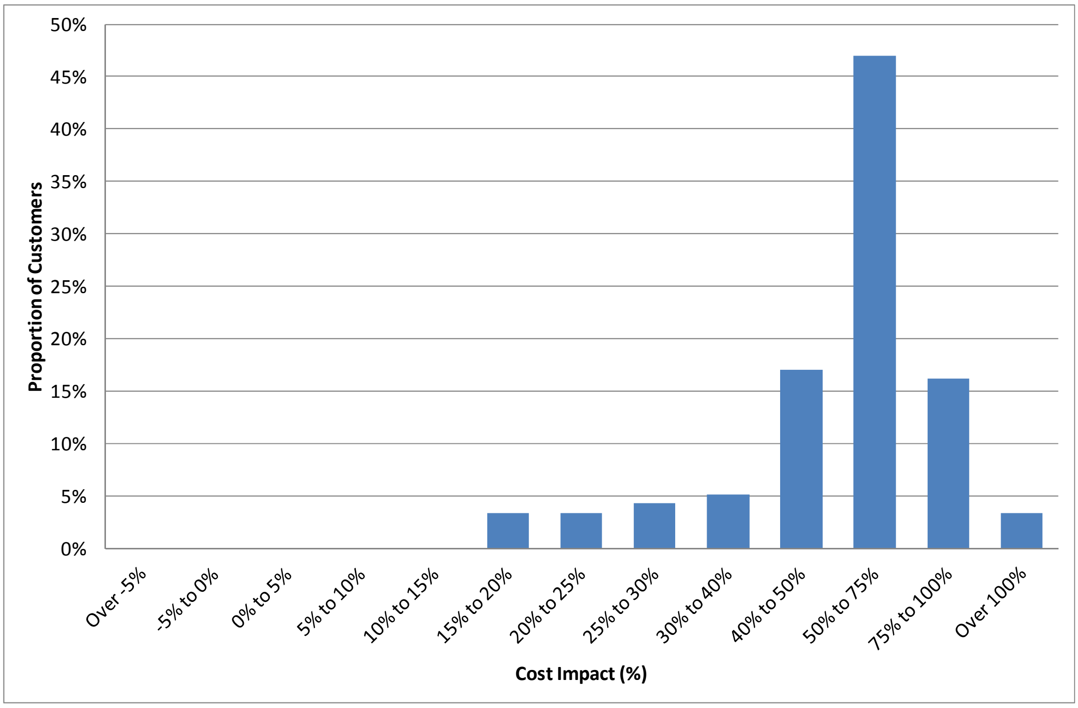
Source: Ergon Energy

Figure 6.15: Change in Electricity Bills for Large Customers on Tariff 65



Source: Ergon Energy

Figure 6.16: Change in Electricity Bills for Large Customers on Tariff 66



Source: Ergon Energy

Price increases for large customers on these tariffs arise mainly because they do not pay any demand charges, whereas all the notified tariffs for large customers include demand charges. As many of these customers have poor load factors, their bills may increase very significantly in moving from their obsolete tariff to the appropriate cost-reflective tariff.

Transitional arrangements for small customers on Tariffs 37, 62, and 65 have already been discussed above, where the Authority decided to retain them for seven years and increase them by 20%. Since the tariffs are to be retained and transitioned for small customers, the Authority considers it would be reasonable to allow these large customers to also remain on these obsolete tariffs.

For Tariff 66, given the potentially significant impact to large customers of moving to one of the cost-reflective Tariffs 44 to 48 and the continuing metering constraints associated with moving large customers to cost-reflective tariffs, the Authority has decided to retain Tariff 66 for seven years, with prices escalated by 20% for 2013-14 (1.25 times the 16% underlying cost increase indicated in Table 6.4). As discussed above, these transitional arrangements will also apply to small customers on Tariff 66.

Access to Obsolete Tariffs

In its 2012-13 Price Determination, the Authority introduced new regulated retail tariffs for large customers in Ergon Energy's network area consuming between 100 MWh and 4 GWh per year (Tariffs 44, 45, 46 and 47) and those consuming more than 4 GWh per year (Tariff 48). These new tariffs were intended to better reflect the costs of supplying these large customers.

The Delegation requires the Authority to consider whether those large customers that have been placed on these new tariffs should be able to access the transitional arrangements (if any) available to similar customers that have been allowed to remain on obsolete tariffs.

In response to the Authority's consultation papers and Draft Determination, the Government suggested that large customers should be allowed to access obsolete tariffs given the current uncertainty about Ergon Energy's future network tariffs and to assist large customers to manage any potential price shocks. Ergon Energy suggested that all customers should be given access to all obsolete tariffs, except for those that were obsolete prior to 1 July 2012 on the basis that these had been obsolete for many years. Ergon Energy considered that not allowing new customers to access obsolete tariffs can, and had, resulted in inequitable outcomes between customers and that allowing access by new customers to obsolete tariffs would be prudent, given the uncertainty within the market and in the context of the UTP.

Some participants in the regional workshops the Authority conducted during November 2012 also queried the limited access to obsolete tariffs. For example, some small customers had shifted from now obsolete farming or irrigation-specific tariffs to Tariff 22 shortly before 1 July 2012 without knowing that the difference between the peak and off-peak charges in Tariff 22 would fall so much from 1 July, causing significant increases in their bills. These customers indicated that, had they been aware of the coming change in retail pricing set to occur from 1 July, they would not have shifted to Tariff 22 and therefore would have been able to enjoy the benefit of whatever transitional arrangements were put in place for their previous (now obsolete) tariff along with similar customers who had not made that switch. QFF and Growcom expressed similar concerns regarding the equity of this situation in their submissions.

AGL, EnergyAustralia, ERAA, ESAA and Energex suggested obsolete tariffs should not be made available to new customers as doing so would create a larger group of customers that need to be transitioned to cost-reflective tariffs, and that it may create financial risk for retailers. In the Draft Determination the Authority highlighted that this may be a concern for retailers and explicitly requested further information about how and by how much this would negatively impact them. Of the retailer submissions that addressed the issue, only brief, broad statements were made without accompanying detail or quantification of financial impacts.

Cotton Australia suggested that new customers should not have access to obsolete tariffs on the basis that new investment decisions should be made with the information available at the time on appropriate tariffs.

As the Authority noted in its consultation papers and Draft Determination, fundamental market reforms, such as the new approach to determining notified prices for 2012-13, often involve detriment to some customers. Such impacts may be an unavoidable element of achieving broader community benefits that flow from significant reforms. For these reasons, the Authority is reluctant to make obsolete tariffs available to new customers because this could exacerbate the inefficiencies that pricing reform was intended to eliminate, as noted by retailers and Energex.

However, the Authority is also concerned that some customers may be facing very large price impacts which they could have avoided had they been aware of the impending changes to notified prices. Further, if large customers should be allowed to have access to obsolete tariffs, as suggested in the Delegation and supported by the Government, then it seems only fair that small customers should be treated the same and allowed to access obsolete tariffs. This view was supported by QFF, Growcom and Ergon Energy. For these reasons, and given the lack of detail from retailers about how relaxing access might negatively impact them, the Authority has decided to relax access to obsolete Tariffs 20 (large), 21, 22 (small and large), 62, 65 and 66 for the duration of the transition periods established above. However, the Authority does not consider it necessary to allow new customers access to Tariffs 41 (large) and 43 (large) given that most customers on these tariffs would be better off on the new cost-reflective tariffs and will be required to shift from their current tariff by the end of 2014-15. Nor does the Authority consider that Tariff 37, which has been obsolete for some time, should be made available to new customers. Ergon Energy supported this view.

The Authority considers that it is unlikely there will be a rush of customers wanting to switch to the reopened tariffs, provided they are adequately informed about the limited period of access and the likely escalation of charges during that period. This should address Cotton Australia's concern that new investment decisions be made based on information about the new cost-reflective tariffs.

Conclusion on Transitional Arrangements

A summary of the Authority's Final Determination on transitional arrangements is provided in Table 6.5. In order to distinguish between obsolete tariffs that will be made available to new customers and tariffs that will remain obsolete and not available to new customers, the Authority has referred to the former as 'transitional' tariffs.

Table 6.5: Transitional Arrangements for Obsolete Tariffs 2013-14

Obsolete/Transitional Tariff	*Retain or Remove in 2013-14*	*Period to be Retained*	*2013-14 Increase*
Tariff 21 – transitional	Retain	7 years	24.0%
Tariff 37 – obsolete	Retain	7 years	20.0%
Tariff 62 – transitional	Retain	7 years	20.0%
Tariff 63	Remove	N/A	N/A
Tariff 64	Remove	N/A	N/A
Tariff 65 – transitional	Retain	7 years	20.0%
Tariff 66 – transitional	Retain	7 years	20.0%
Tariff 20 (large) – transitional	Retain	7 years	14.3%
Tariff 22 (small and large) – transitional	Retain	7 years	16.3%
Tariff 41 (large) – obsolete	Retain	2 years	14.3%
Tariff 43 (large) – obsolete	Retain	2 years	14.3%
Tariff 53 (large)	Remove	N/A	N/A

7. FINAL DETERMINATION

This chapter sets out the Authority's Final Determination of regulated retail electricity prices (notified prices) to apply from 1 July 2013 to 30 June 2014, as well as expected customer impacts.

7.1 Cost-Reflective Retail Tariffs and Prices

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

Chapters 3 and 4 set out the Authority's decisions on energy costs and retail costs which together comprise the R component of retail tariffs.

Network Costs

As discussed in Chapter 2, the Authority has based the 2013-14 regulated retail tariffs on network tariffs drawn from both Energex and Ergon Energy as follows:

(a) Energex network tariffs and charges for customers with consumption up to 100MWh per year and for unmetered loads other than street lighting; and

(b) Ergon Energy network tariffs and charges for customers with consumption greater than 100MWh per year and for street lighting.

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

The network tariffs and charges form the basis of the build-up of regulated retail tariffs presented in **Appendix D**.

Energy Costs

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

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

(a) 8.671 cents per kWh for tariffs where consumption is settled on the Energex NSLP (Tariffs 11, 12, 13, 20, 22, 41 and 91);

(b) for tariffs where consumption is settled on the Ergon Energy NSLP:

   (i) 8.565 cents per kWh for SAC demand tariffs (Tariffs 44, 45, 46) and the street lighting tariff (Tariff 71); and

   (ii) 8.210 cents per kWh for the SAC HV tariffs (Tariffs 47 and 48); and

(c) for controlled load tariffs:

   (i) 6.271 cents per kWh for the night rate (super economy) tariff (Tariff 31); and

(ii) 7.433 cents per kWh for the controlled supply (economy) tariff (Tariff 33).

The energy costs that will apply to each regulated retail tariff are shown in the build-up of regulated retail tariffs presented in **Appendix D**.

Retail Operating Costs

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

(a) 44.397 cents per customer per day has been applied to tariffs where consumption is less than 100 MWh per annum (Tariffs 11, 12, 13, 20, 22 and 41);

(b) 196.788 cents per customer per day has been applied to tariffs where consumption is generally between 100 MWh and 4 GWh per annum (Tariffs 44, 45, 46 and 47);

(c) 561.607 cents per customer per day has been applied to the tariff where consumption is generally greater than 4 GWh per annum (Tariff 48); and

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

The ROC that will apply to each regulated retail tariff is shown in the build-up of regulated retail tariffs presented in **Appendix D**.

Retail Margin

As discussed in Chapter 4, the Authority has set the retail margin at 6.0% on top of total costs excluding the margin.

The retail margin is applied equally (on a percentage basis) to each component of each retail tariff. The retail margin that will apply to each regulated retail tariff is shown in the build-up of regulated retail tariffs presented in **Appendix D.**

Headroom

As discussed in Chapter 5, the Authority has included an additional allowance of 5% of total costs for headroom to foster competition.

Headroom is applied equally (on a percentage basis) to each component of each retail tariff. The headroom that will apply to each regulated retail tariff is shown in the build-up of regulated retail tariffs presented in **Appendix D**.

7.2 Final Determination

The Authority's Final Determination is that the notified prices to apply for the period 1 July 2013 to 30 June 2014 are as set out in Tables 7.1 to 7.4 below.

The charges for Tariff 11 presented below have been determined based on the first step in the transition from the frozen charges for Tariff 11 in 2012-13 to cost-reflective levels, as discussed in Chapter 6.

A retail entity must charge notified prices to its non-market customers. New and existing non-residential customers in the Energex distribution area who consume over 100 MWh per annum do not have to access notified prices and must be on a market contract.

Table 7.1: 2013-14 Regulated Retail Tariffs and Prices for Residential Customers (GST Exclusive)

Retail tariff	*Energex network tariff*	*Fixed charge[a]*	*Variable rate (flat)*	*Variable rate 1 (off-peak)*	*Variable rate 2 (shoulder)*	*Variable rate 3 (peak)*
		c/day	*c/kWh*	*c/kWh*	*c/kWh*	*c/kWh*
Tariff 11 - Residential (flat rate)	8400	50.219	26.730			
Tariff 12 - Residential (time of use)	8900	113.904		19.430	22.412	30.968
Tariff 13 - Residential (PeakSmart)	7600	113.904		17.203	22.412	30.968
Tariff 31 - Night rate (super economy)	9000		12.370			
Tariff 33 - Controlled supply (economy)	9100		18.052			

a. Charged per metering point.

Table 7.2: 2013-14 Regulated Retail Tariffs and Prices for Other Small Customers and Unmetered Supplies Other Than Street Lighting (GST Exclusive)

Retail tariff	*Energex network tariff*	*Fixed charge[a]*	*Demand charge*	*Variable rate (flat)*	*Variable rate (off-peak)*	*Variable rate (peak)*
		c/day	*$/kW/month*	*c/kWh*	*c/kWh*	*c/kWh*
Tariff 20 - Business (flat rate)	8500	130.161		23.218		
Tariff 22 - Business (time of use)	8800	130.161			18.668	25.496
Tariff 41 - Low voltage(demand)	8300	803.475	23.257	11.257		
Tariff 91 - Unmetered	9600			20.175		

a. Charged per metering point.

Table 7.3: 2013-14 Regulated Retail Tariffs and Prices for Large Customers and Street Lighting (GST Exclusive)

Retail tariff	*Ergon Energy network tariff*	*Fixed charge[a]*	*Demand charge*	*Variable rate (flat)*
		c/day	*$/kW/month*	*c/kWh*
Tariff 44 - Over 100 MWh small (demand)	EDST1	867.823	35.277	11.667
Tariff 45 - Over 100 MWh medium (demand)	EDMT1	2,708.163	30.605	11.667
Tariff 46 - Over 100 MWh large (demand)	EDLT1	4,275.146	29.413	11.667
Tariff 47 - High voltage (demand)	EDHT1	2,786.996	23.504	11.205
Tariff 48 – Over 4 GWh High voltage (demand)	EDHT1	3,193.210	23.504	11.205
Tariff 71 - Street lighting [b]	EVUT1	0.668	0.000	35.631

a. Charged per metering point. b. The fixed charge for street lighting applies to each lamp.

As discussed in Chapter 6, for transitional purposes, the Authority has retained nine retail tariffs that had been declared obsolete. The Authority's Final Determination on the notified prices that will apply to these tariffs is set out in Table 7.4 below. From 1 July 2013, new customers will also be able to access Tariffs 20 (large), 21, 22 (small and large), 62, 65 and 66 but they should be aware that each of these tariffs now has a set sunset date (as set out in Chapter 6) after which they will no longer be available to any customers.

Table 7.4: 2013-14 Transitional and Obsolete Regulated Retail Tariffs and Prices

Retail tariff	*Fixed charge*[b]	*Min Charge*	*Variable rate 1*[c]	*Variable rate 2*[d]	*Variable rate 3*[e]	*Variable rate (flat)*	*Demand flat*	*Capacity (Up to 7.5kw)*	*Capacity (Over 7.5kw)*
	c/day	*c/day*	*c/kWh*	*c/kWh*	*c/kWh*	*c/kWh*	*$/kW/mth*	*$/kW/yr*	*$/kW/yr*
Obsolete tariffs for small customers and Ergon Energy large customers									
Tariff 37[a]		24.932	17.755		44.410				
Transitional tariffs for small customers and Ergon Energy large customers									
Tariff 21		63.064	42.854	40.265	30.653				
Tariff 22	145.698		39.297		13.838				
Tariff 62	65.918		39.085	33.053	13.820				
Tariff 65	65.918		31.178		17.173				
Tariff 66	145.282					16.342		31.693	95.291
Obsolete Tariffs for large customers in Ergon Energy's network area									
Tariff 41(large)[a]	219.231					9.848	46.840		
Tariff 43(large)[a]	219.231		20.039		8.010		20.286		
Transitional Tariffs for large customers in Ergon Energy's network area									
Tariff 20(large)	59.606					29.157			

a. New customers are not eligible for these retail tariffs.

b. Charged per metering point.

c. Tariff 21 – first 100kWh per month, Tariff 22(small and large) – 7am-9pm M-F, Tariff 37 – 10:30pm-4:30pm, Tariff 43 (large) – 7am-11pm M-F, Tariff 62 – 7am-9pm M-F first 10,000kWh per month, Tariff 65 – 12hr peak.

d. Tariff 21 – 101-10,000kWh per month, Tariff 62 – 7am-9pm M-F over 10,000kWh per month.

e. Tariff 21 – over 10,000 kWh per month, Tariff 22(small and large) – all other times, Tariff 37 – 4:30pm-10:30pm, Tariffs 43, 62 & 65 – all other times.

The regulated retail tariffs and notified prices will be published in a tariff schedule which includes a range of other information, including the eligibility criteria and other terms and conditions for each regulated retail tariff.

A final tariff schedule for 2013-14 is provided in **Appendix E**.

The Authority has removed Tariffs 53 (large), 63 and 64 from the regulated tariff schedule (as discussed in Chapter 6). Customers remaining on Tariff 53 (large) as at 1 July 2013 will be moved to the most appropriate large customer tariff (Tariffs 44 to 48), and those on Tariffs 63 and 64 will be moved to Tariffs 62 and 65 respectively, unless an alternative cost-reflective tariff (Tariff 20 or 22) would be more suitable for them.

7.3 Underlying Cost Drivers

Cost-reflective notified prices will increase in 2013-14 due to increases in the underlying costs of supply, which are predominately driven by increases in network charges. On average, network charges will increase by around 19% for Energex and 17% for Ergon Energy. These increases reflect:

(a) Large increases in the distributors' revenue allowed by the Australian Energy Regulator;

(b) The significant costs that the distributors have incurred in complying with the Queensland Government's Solar Bonus Scheme. For example, Energex estimates that 9.2% of its 2013-14 network tariffs relate to the costs of complying with the Solar Bonus Scheme. These costs are expected to increase significantly in future years and their impact on network tariffs will peak in 2015-16, at which time approximately 29.5% of Energex's network tariffs will be due to Solar Bonus Scheme costs;

(c) The catch-up from the Queensland Government's Tariff 11 freeze in 2012-13, which was partly funded by a $40 million subsidy to Energex;

(d) Additional revenue to make up for under-recovered revenue in earlier years due to lower than forecast consumption; and

(e) The impact of declining consumption (some part of which is included in the Solar Bonus Scheme costs above) which means that network charges must increase to recover the allowed revenue.

Energy costs are the next biggest cost driver and are estimated to increase by around 9.0% (marginally higher than estimated in the Draft Determination). This increase is due to a tightening of the futures market and uncertainty in the market which has increased the risks faced by retailers in purchasing wholesale energy.

Retail operating costs have also increased (by 24%, up from 2.5% in the Draft Determination) for small customers. This significant change comes as a result of the benchmarking approach being updated to take account of IPART's most recent estimates of retail operating costs. While the percentage increase is significant, the retail cost component is the smallest of the three and therefore the impact on costs is less than for network or energy costs.

The impact of cost increases on individual customers will vary depending on the retail tariff(s) they are supplied under and their consumption characteristics.

7.4 Customer Impacts

Figures 7.1 and 7.2 show the percentage changes that typical customers can expect in their annual electricity bills moving from 2012-13 to 2013-14.

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

Figure 7.1 shows the percentage changes that typical residential customers can expect in their annual electricity bills from 2012-13 to 2013-14 for each of the residential tariffs. For Tariff 11, bill impacts will vary depending on each individual customer's level of consumption, but will generally be higher (in percentage terms) for those consuming less than the average. For Tariff 12, bill impacts will vary depending on both the level of each individual customer's consumption and the time of day they consume. The bill impacts for

Tariff 12 are lower than for other tariffs mainly because the underlying network charge for peak consumption has decreased relative to 2012-13.

Figure 7.1: Change in Electricity Bills in 2013-14 for Residential Customers

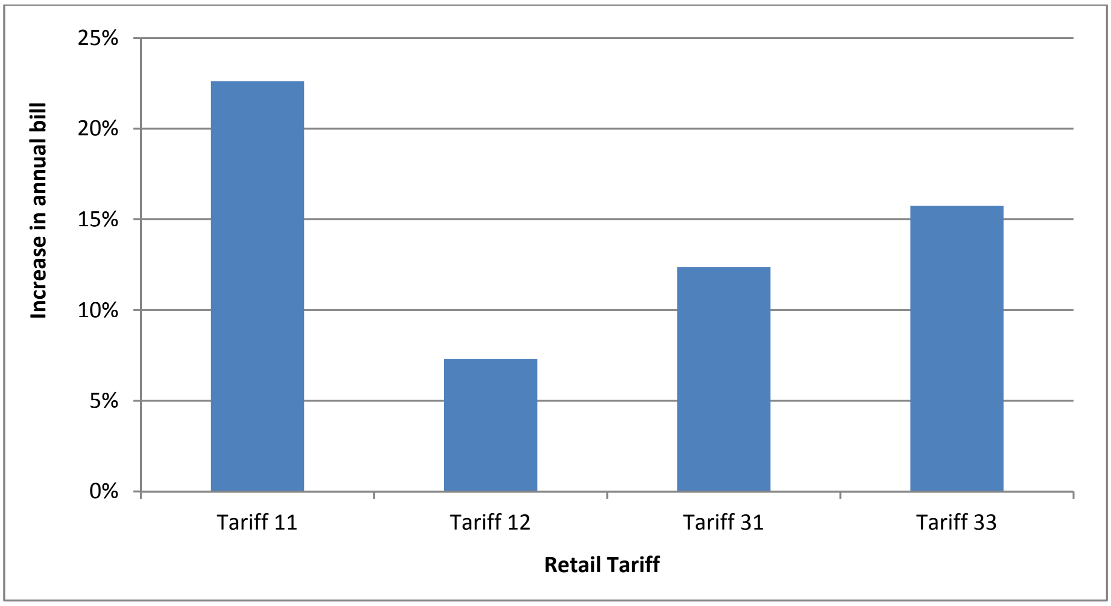
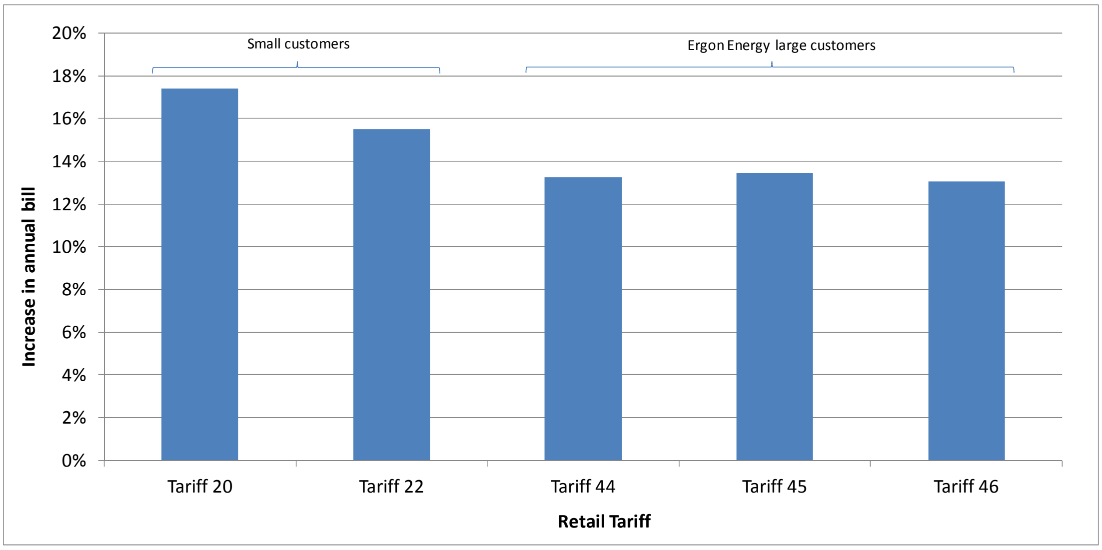


Figure 7.2 presents the increases in annual bills for typical business customers on the cost-reflective business tariffs. Bill impacts will vary depending on each individual customer's level and pattern of consumption.

Figure 7.2: Change in Electricity Bills in 2013-14 for Business Customers[a]



a. Tariffs 41, 47 and 48 are not included due to a lack of useable data at this time.

Customer impacts and percentage increases for obsolete and transitional tariffs are discussed in Chapter 6.

Tariff 11

Analysis of the impacts of the tariff freeze and transitional arrangements on residential Tariff 11 customers is provided in Chapter 6. Table 7.5 provides further scenarios to give a wider illustration of impacts for different types of customers. The table shows that the lower a customer's consumption, the higher will be the percentage increase in the customer's bill. This is due to the impact of the rising fixed charge which has increased by more than the variable charge due to the rebalancing of fixed and variable charges towards cost-reflectivity.

While a number of stakeholders remained concerned about the impact of these changes to Tariff 11 on vulnerable households, the Authority retains its view that prices should be set according to cost and that the needs of financially vulnerable consumers would be best met via targeted welfare assistance measures. A summary of current assistance arrangements directly targeting energy costs is provided in **Appendix G** and it is open to Government to consider whether these measures provide the level of relief it considers appropriate in the current circumstances.

Table 7.5: Change in Electricity Bills in 2013-14 for Tariff 11

Customer Type	*Annual consumption (kWh)*	*2012-13 Annual Bill*	*2013-14 Annual Bill*	*Typical increase*	*Typical increase*
Mostly vacant holiday home	1,000	$358.93	$495.79	$136.87	38.1%
Frugal single elderly person	2,200	$663.46	$848.63	$185.17	27.9%
Frugal elderly couple; high-earner young single person	3,070	$884.15	$1,104.32	$220.17	24.9%
Single parent one child; couple no children	4,091	$1,143.41	$1,404.70	$261.28	22.9%
Couple with one child; single parent two children;	5,112	$1,402.47	$1,704.84	$302.37	21.6%
Two parent, two child family	6,133	$1,661.53	$2,004.98	$343.45	20.7%
Two parents, two children, pool; Two parents four children	8,490	$2,259.64	$2,697.95	$438.31	19.4%
Two parents, four children, pool; Two parents six children	10,572	$2,788.12	$3,310.24	$522.12	18.7%

Note – Tariff 11 customers will typically also have some consumption under one of the off-peak tariffs (Tariff 31 or Tariff 33).

APPENDIX A: MINISTERIAL DELEGATION AND COVER LETTER

A.1: Ministerial Delegation and Cover Letter (dated 12 February 2013)

QUEENSLAND GOVERNMENT

Office of the Minister for Energy and Water Supply

Ref: EWS/002748
CTS 02289/13

Level 13 Mineral House
41 George Street Brisbane 4000
PO Box 15456 City East
Queensland 4002 Australia
Telephone +61 7 3896 3691
Facsimile +61 7 3012 9115

12 February 2013

Dr Malcolm Roberts
Chairman
Queensland Competition Authority
GPO Box 2257
BRISBANE QLD 4001

Dear Dr Roberts

I refer to the current Delegation and Terms of Reference (ToR), issued to the Queensland Competition Authority (QCA) on 5 September 2012, for determining regulated retail electricity prices for the three year delegation period 2013–14 to 2015–16 (with annual price determinations published each year), as authorised under section 90AA(1) of the *Electricity Act 1994* (the Act). Under the current Delegation, the Draft Determination on regulated prices for 2013–14 is required to be released no later than 15 February 2013.

In acknowledging your recent appointment as Chairman of the QCA Board on 29 January 2013, I have amended the current Delegation and ToR to extend the date for the release of the Draft Determination to 22 February 2013. I trust that this will provide the Board with additional time to comprehensively consider the QCA's Draft Determination for 2013–14 regulated retail prices, in advance of its public release.

Accordingly, I have attached a new Certificate of Delegation and ToR directing the QCA to publish the Draft Determination on regulated retail electricity prices for 2013–14 on 22 February 2013.

I thank the QCA for its work to date on the 2013–14 regulated pricing process, and will continue to encourage stakeholders to actively participate in the QCA's ongoing consultation process.

Should you require anything further, please contact Mr Benn Barr, A/Deputy Director-General, Energy Sector Reform, on 323 90039, or email benn.barr@dews.qld.gov.au.

Yours sincerely

[redacted]

Mark McArdle MP
Minister for Energy and Water Supply

Att: Electricity Act 1994 Delegation

Page **1** of **1**

DELEGATION TO QCA

ELECTRICITY ACT 1994
Section 90AA(1)

DELEGATION

I, Mark McArdle, the Minister for Energy and Water Supply, in accordance with the power of delegation in section 90AA(1) of the *Electricity Act 1994* (the Act), delegate to the Queensland Competition Authority (QCA) the function under section 90(1) of the Act of deciding the prices that a retail entity may charge its non-market customers for customer retail services for the tariff years from 1 July 2013 to 30 June 2016.

The following are the Terms of Reference of the price determination:

Terms of Reference

1. These Terms of Reference apply for each of the tariff years in the delegation period.

2. In each tariff year of the delegation period, QCA is to calculate the notified prices and publish an annual price determination, in the form of a tariff schedule, in accordance with these Terms of Reference.

3. In accordance with section 90(5)(a) of the Act, in making a price determination for each tariff year QCA must have regard to all of the following:

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

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

   (c) the matters set out in paragraph 5 of these Terms of Reference.

4. In accordance with section 90(5)(b) of the Act, QCA may have regard to any other matter that QCA considers relevant.

5. The matters that QCA is required by this delegation to consider are:

   (a) Uniform Tariff Policy - QCA must consider the Government's Uniform Tariff Policy, which provides that, wherever possible, non-market customers of the same class should have access to uniform retail tariffs and pay the same notified price for their electricity supply, regardless of their geographic location;

   (b) Time of Use Pricing – QCA must consider whether its approach to calculating time-of-use tariffs can strengthen or enhance the underlying network price signals and encourage customers to switch to time-of-use tariffs and reduce their energy consumption during peak times;

(c) Framework - QCA must use the Network (N) plus Retail (R) cost build-up methodology when working out the notified prices and making the price determination, where N (network cost) is treated as a pass-through and R (energy and retail cost) is determined by QCA;

(d) When determining the N components for each regulated retail tariff for each tariff year, QCA must consider the following:

(i) for residential and small business customers, that is, those who consume less than 100 megawatt hours (MWh) per annum - basing the network cost component on the network charges to be levied by Energex;

(ii) for large business customers in the Ergon Energy distribution region who consume 100MWh or more per annum - basing the network cost component on the network charges to be levied by Ergon Energy given that, from 1 July 2012, large business customers in the Energex distribution region no longer have access to notified prices;

(e) Transitional Arrangements - QCA must consider:

(i) for the standard regulated residential tariff (Tariff 11), implementing a three-year transitional arrangement to rebalance the fixed and variable components of Tariff 11, so that each component (fixed and variable) of Tariff 11 is cost-reflective by 1 July 2015;

(ii) for the existing obsolete tariffs (i.e. farming, irrigation, declining block, non-domestic heating and large business customer tariffs), implementing an appropriate transitional arrangement should QCA consider there would be significant price impacts for customers on these tariffs if required to move to the alternative cost-reflective tariffs; and

(iii) for the large business customer tariffs introduced in 2012-13 (i.e. Tariffs 44, 45, 46, 47 and 48), whether customers on these tariffs should be able to access the transitional arrangements for the obsolete large business customer tariffs should QCA consider that a transitional arrangement for the obsolete tariffs is necessary.

Interim Consultation Paper

6. As part of each annual price determination, QCA must publish an interim consultation paper identifying key issues to be considered when calculating the N

and R components of each regulated retail electricity tariff and transitioning relevant retail tariffs over the three-year delegation period.

7. QCA must publish a written notice inviting submissions about the interim consultation paper. The notice must state a period during which anyone can make written submissions to QCA about issues relevant to the price determination.

8. QCA must consider any submissions received within the consultation period and make them available to the public, subject to normal confidentiality considerations.

Consultation Timetable

9. As part of each annual price determination, QCA must publish an annual consultation timetable within two weeks after submissions on the interim consultation paper are due, which can be revised at the discretion of QCA, detailing any proposed additional public papers and workshops that QCA considers would assist the consultation process.

Workshops and additional consultation

10. As part of the Interim Consultation Paper and in consideration of submissions in response to the Interim Consultation Paper the QCA must consider the merits of additional public consultation (workshops and papers) on identified key issues.

11. Specifically, given the three-year period of the delegation the QCA must conduct a public workshop on the energy and retail cost components used to determine regulated retail tariffs prior to the release of the 2013-14 Draft Determination.

Draft Price Determination

10. As part of each annual price determination, QCA must investigate and publish an annual report of its draft price determination on regulated retail electricity tariffs, with each tariff to be presented as a bundled price, for the relevant tariff year. The draft price determination must also specify the carbon cost allowances for the relevant tariff year.

11. QCA must publish a written notice inviting submissions about the draft price determination. The notice must state a period during which anyone can make written submissions to QCA about issues relevant to the draft price determination.

12. QCA must consider any submissions received within the consultation period and make them available to the public, subject to normal confidentiality considerations.

DELEGATION TO QCA

Final Price Determination

13. As part of each annual price determination, QCA must investigate and publish an annual report of its final price determination on regulated retail electricity tariffs, with each tariff to be presented as a bundled price, for the relevant tariff year, and gazette the bundled retail tariffs. The final price determination must also specify the carbon cost allowances for the relevant tariff year.

Timing

14. QCA must make its reports available to the public and, at a minimum, publicly release for each tariff year the papers and price determinations listed in paragraphs 6 to 13.

15. QCA must publish the interim consultation paper for the 2013-14 tariff year no later than one month after the date of this Delegation and no later than 30 August before the commencement of the subsequent tariff years.

16. QCA must publish the draft price determination on regulated retail electricity tariffs on 22 February 2013 for the 2013-14 tariff year and no later than 13 December before the commencement of the subsequent tariff years.

17. QCA must publish the final price determination on regulated retail electricity tariffs for each relevant tariff year, and have the bundled retail tariffs gazetted, no later than 31 May each year.

18. This Delegation revokes my previous Delegation issued on 5 September 2012.

DATED this 12th day of February 2013.

[redacted]

SIGNED by the Honourable)
Mark McArdle,)
Minister for Energy and Water Supply) ....
(signature)

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A.2 Cover Letter to Original Delegation (dated 4 September 2012)

QUEENSLAND GOVERNMENT

Office of the Minister for Energy and Water Supply

Ref: EWS/001799
MBN6648

Level 13 Mineral House
41 George Street Brisbane 4000
PO Box 15456 City East
Queensland 4002 Australia
Telephone +61 7 3896 3691
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4 September 2012

Mr Brian Parmenter
Chairman
Queensland Competition Authority
GPO Box 2257
Brisbane Qld 4001

Dear Mr Parmenter

I attach a Delegation and Terms of Reference (ToR) to the Queensland Competition Authority (QCA) to determine regulated retail electricity prices for the next three years (with annual determinations published each year), as authorised under Section 90AA(1) of the *Electricity Act 1994* (the Act).

The Queensland Government has taken action to address cost of living pressures. In relation to regulated retail electricity prices in 2012-13, the Government froze the standard residential tariff (Tariff 11) (plus the cost of carbon) as a short-term cost of living relief measure.

The Delegation and ToR contains a number of important measures designed to assist Queenslanders in dealing with changes to electricity prices. More information on these measures is provided below.

1. Three year Delegation and ToR

This is the first Delegation on regulated retail electricity prices from this Government, and in order to provide a degree of certainty to consumers and industry, a move from an annual price determination to a three year delegation period will apply. For consumers, the Government is committed to an approach that will assist in managing short-term price shocks, and for industry an approach that may assist in the longer term investment in the sector.

The Government is seeking from the QCA a strong consultation process with a clear focus on key issues, with regard to the objectives of the Act as set out in this Delegation and ToR.

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2. Consideration of customer impacts and 'transitional arrangements'

The Government is committed to tariff reform and addressing the cost drivers of electricity prices. However, this reform needs to be carefully managed and it is important that the QCA take into account the impacts of price increases on struggling Queensland households and businesses. To assist with this, the QCA is directed to consider transitional pricing arrangements over a number of years for a range of customers accessing the following tariffs:

- Tariff 11 (the standard residential tariff);
- Transitional and obsolete tariffs, including farming and irrigation tariffs; and
- Large business tariffs in Ergon Energy's distribution area.

Whilst the Government's freeze to Tariff 11 in 2012-13 provided households with immediate relief from cost of living increases, this was a short-term measure only. However, the Government expects the QCA to ensure that Queensland households experience a smooth transition from the freeze and to fully utilise the three-year delegation period to order to achieve this.

The other tariffs noted above have been chosen for transitional measures based on the unacceptable impacts for some customers accessing these tariffs, as identified by the QCA in their Draft and Final Determinations for 2012-13. Transitional arrangements over the three-year delegation period should be designed to assist in mitigating these potential impacts.

3. Extensive Consultation with Stakeholders and the Community

The QCA is required to undertake a rigorous consultation process with all relevant parties and consider all submissions received. The QCA is not limited by the consultation schedule outlined in the Delegation and ToR and, should undertake additional consultation on key issues, and as appropriate, publish the results of this consultation.

An important aspect of the consultation process will be the publication of a consultation timetable within two weeks after submissions on the interim consultation paper are due, detailing any proposed additional public papers (other than those required by the Delegation and ToR). It is critical that all stakeholders, including retailers, customers and consumer advocacy groups understand the intent and timing of this crucial process.

Furthermore, given the three-year period of this delegation (compared to one-year delegations issued in the past) it is important that continuity in decision making is maintained in regard to key cost components. Therefore, the QCA must conduct a public workshop prior to the release of the 2013-14 Draft Determination on how the energy and retail cost components of regulated retail tariffs should be determined.

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4. Public Communication of QCA Decisions/Determinations

Every Queenslander is impacted by electricity price increases, so there will be significant public interest in the QCA's determination of regulated tariffs. Because of this, the Queensland Government expects the QCA to fully explain its decisions and encourages the QCA to, at a minimum, publish and communicate the outcomes of its reports in a clear and concise fashion using consumer oriented fact sheets and media releases. Access to this additional material should be easily accessible on the QCA website and be obvious to any new visitor to the QCA site.

5. Other matters in the Delegation and ToR

Time-of-Use Tariffs

Queensland customers should be rewarded for shifting their consumption of electricity from peak periods to off-peak periods, which has material benefits for network and generation infrastructure. The QCA should determine whether its approach to determining the rates for time-of-use tariffs can strengthen or enhance the underlying network price signals and encourage customers to switch to time-of-use tariffs and reduce their energy consumption during peak times.

Finally, I would like to point out the Queensland Government has established longer-term reform processes to address unsustainable electricity price increases. This includes establishing an Inter-departmental Committee (IDC) on Electricity Sector Reform. In recognising the key role that the cost of poles and wires (transmission and distribution networks) has on electricity prices, an Independent Review Panel (IRP) is examining the cost of these networks. These reform processes are currently underway and scheduled to report back to Government in late January 2013.

I look forward to following the QCA process for determining regulated retail electricity prices and will be encouraging stakeholders to actively participate in the consultation process, and to assist the QCA at every turn in understanding the potential impacts arising from the determination of regulated retail electricity prices.

Yours sincerely

[redacted]

Mark McArdle MP
Minister for Energy and Water Supply

Att

APPENDIX B: SUBMISSIONS

Table B.1: Submissions in Response to the Interim Consultation Paper

	Organisation/Individual
1.	AGL
2.	Atherton, P.G.
3.	Australian Sugar Milling Council
4.	Bundaberg Walkers Engineering Ltd
5.	Canegrowers
6.	CQMS Razer
7.	Dobinsons Spring & Suspension
8.	Energex
9.	EnergyAustralia
10.	Energy Options
11.	Energy Supply Association of Australia and Energy Retailers Association of Australia (Joint Submission)
12.	Ergon Energy
13.	Growcom
14.	Mareeba-Dimbulah Irrigation Area Council
15.	Meridian Energy Australia
16.	Origin Energy
17.	Pioneer Valley Water
18.	Queensland Council of Social Service Inc
19.	Queensland Farmers' Federation
20.	Queensland Government
21.	Shopping Centre Council of Australia
22.	Toowoomba Regional Council
23.	Confidential Submission

Table B.2: Submissions in Response to the Transitional Issues Paper

	Organisation/Individual
1.	AGL
2.	Association of Independent Retirees
3.	Australian Sugar Milling Council
4.	Brimblecombe, I
5.	Bundaberg Regional Irrigators Group
6.	Bundaberg Walkers Engineering Ltd
7.	Canegrowers Isis
8.	Dobinsons Spring & Suspension
9.	Energex
10.	Energy Supply Association of Australia and Energy Retailers Association of Australia (joint submission)
11.	Ergon Energy
12.	IOR Terminals Pty Ltd
13.	ISIS Central Sugar Mill Co. Ltd
14.	Linton, J
15.	Lower Burdekin Water
16.	Mareeba-Dimbulah Irrigation Area Council
17.	Morawitz, CA & G
18.	National Seniors Australia
19.	Origin Energy
20.	Pioneer Cane Growers
21.	Queensland Consumers' Association
22.	Queensland Council of Social Service Inc
23.	Queensland Government
24.	Simply Energy
25.	Sucrogen
26.	SunWater
27.	Surfpoint Pty Ltd
28.	2PH Farms

Table B.3: Submissions in Response to the Cost Components Paper

	Organisation/Individual
1.	Agforce
2.	AGL
3.	Alinta Energy
4.	Association of Independent Retirees
5.	Canegrowers
6.	CCIQ
7.	Cotton Australia
8.	Energex
9.	EnergyAustralia
10.	Energy Supply Association of Australia and Energy Retailers Association of Australia (joint submission)
11.	Ergon Energy
12.	MSF Sugar
13.	Origin Energy
14.	Origin Energy supplementary submission
15.	Pioneer Valley Water
16.	Queensland Consumers' Association
17.	Queensland Council of Social Service Inc
18.	QEnergy
19.	Queensland Farmers' Federation
20.	Seafarm
21.	Simply Energy
22.	Stanwell
23.	Toowoomba Regional Council
24.	Confidential submission

Table B.4: Submissions in Response to the Draft Determination

	Organisation/Individual
1.	AGL
2.	Alinta Energy
3.	Australian Industry Group
4.	Australian Sugar Milling Council
5.	Beck, I
6.	Bell, G
7.	Black, J & B
8.	Brimblecombe, I
9.	Bundaberg Walkers Engineering Ltd
10.	Canegrowers
11.	Canegrowers Herbert River
12.	Canegrowers Isis
13.	CCIQ
14.	Clean Energy Council
15.	Click Energy
16.	Cotton Australia
17.	Cuzens N, J, R & P
18.	Dobinsons Spring & Suspension
19.	Electrical Contractors Association
20.	Energex
21.	Energy Australia
22.	Energy Supply Association of Australia and Energy Retailers Association of Australia (joint submission)
23.	Ergon Energy
24.	Hilliar, J, V & P
25.	ISIS Central Sugar Mill Co. Ltd
26.	Lockyer Irrigators
27.	Mackay Sugar
28.	Mareeba Dimbulah Irrigation Area Council
29.	McCarthy, G
30.	McCosker, M
31.	Millar, H
32.	Momentum Energy
33.	Morawitz, C
34.	MSF Sugar
35.	Origin Energy
36.	Pioneer Cane Growers
37.	Pioneer Valley Water
38.	QEnergy
39.	Queensland Cotton

40.	Queensland Council of Social Service Inc
41.	Queensland Government
42.	Queensland Farmers' Federation
43.	Simply Energy
44.	Stanwell
45.	Stewart, A
46.	Sucrogen
47.	Toowoomba Regional Council
48.	2PH Farms

APPENDIX C: ERGON ENERGY CUSTOMER IMPACTS

All data for these figures was provided by Ergon Energy.

SMALL CUSTOMERS

Figure C.1: Change in Electricity Bills in 2013-14 for Customers on Tariff 21

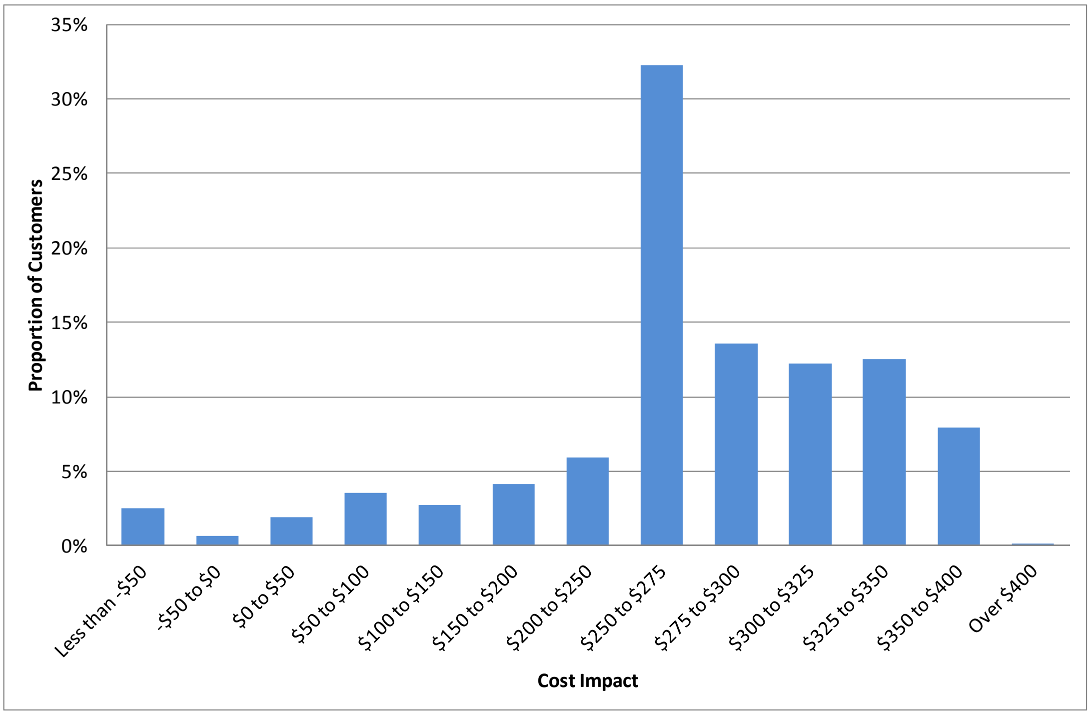


Figure C.2: Change in Electricity Bills in 2013-14 for Customers on Tariff 37

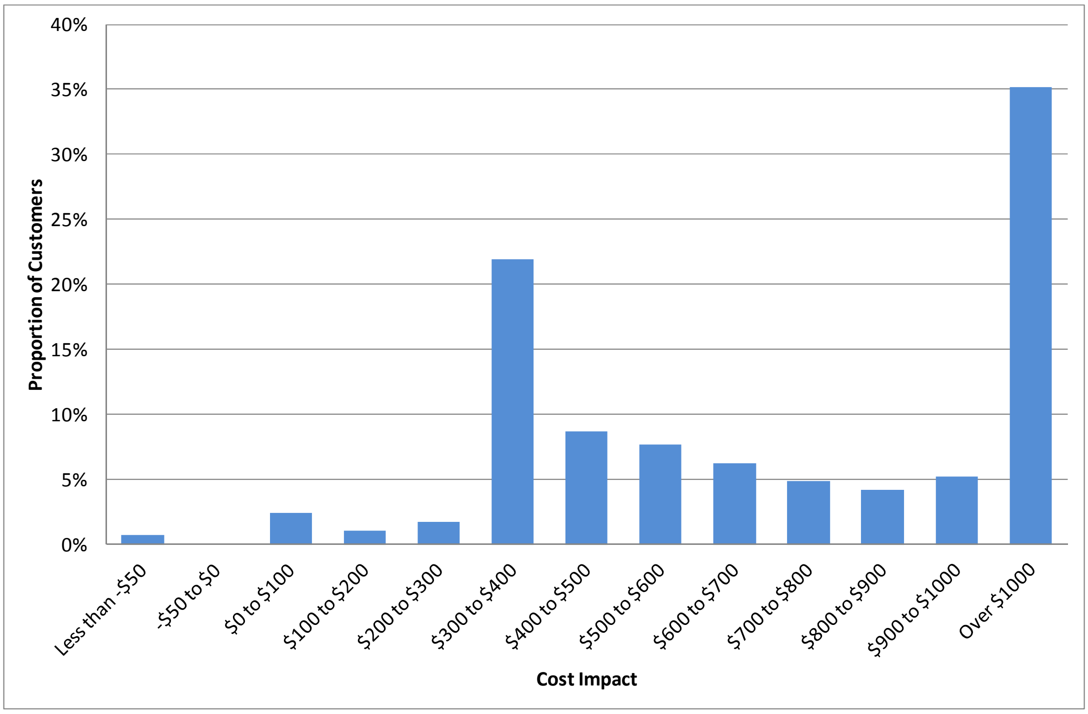


Figure C.3: Change in Electricity Bills in 2013-14 for Customers on Tariffs 62 & 63

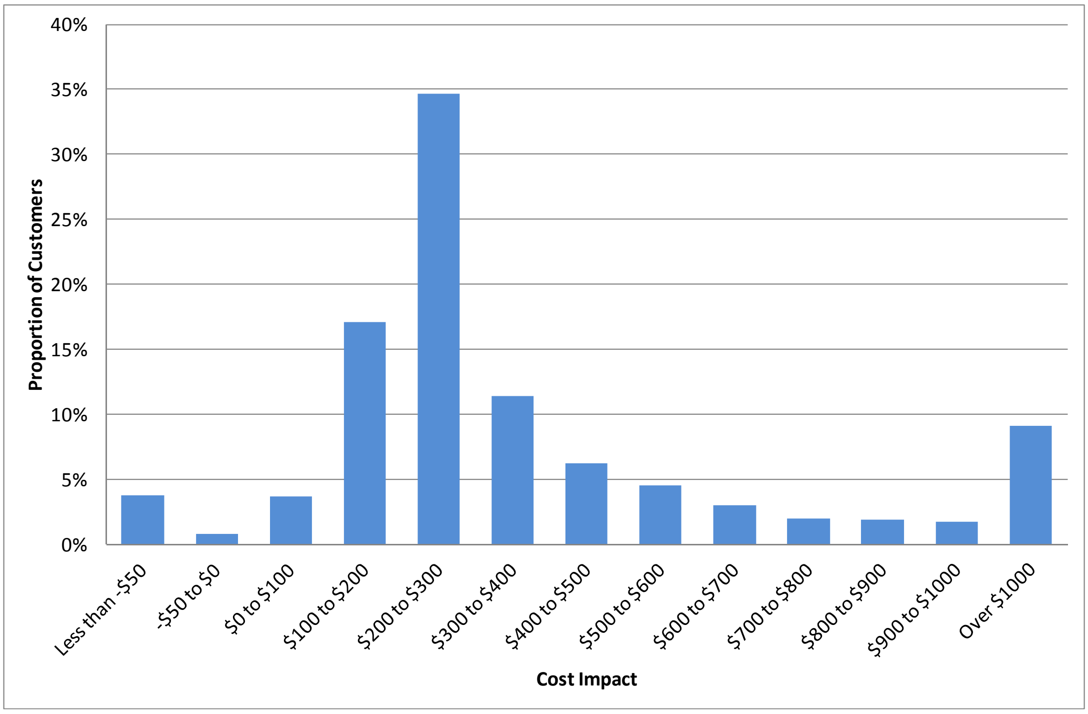


Figure C.4: Change in Electricity Bills in 2013-14 for Customers on Tariffs 64 & 65

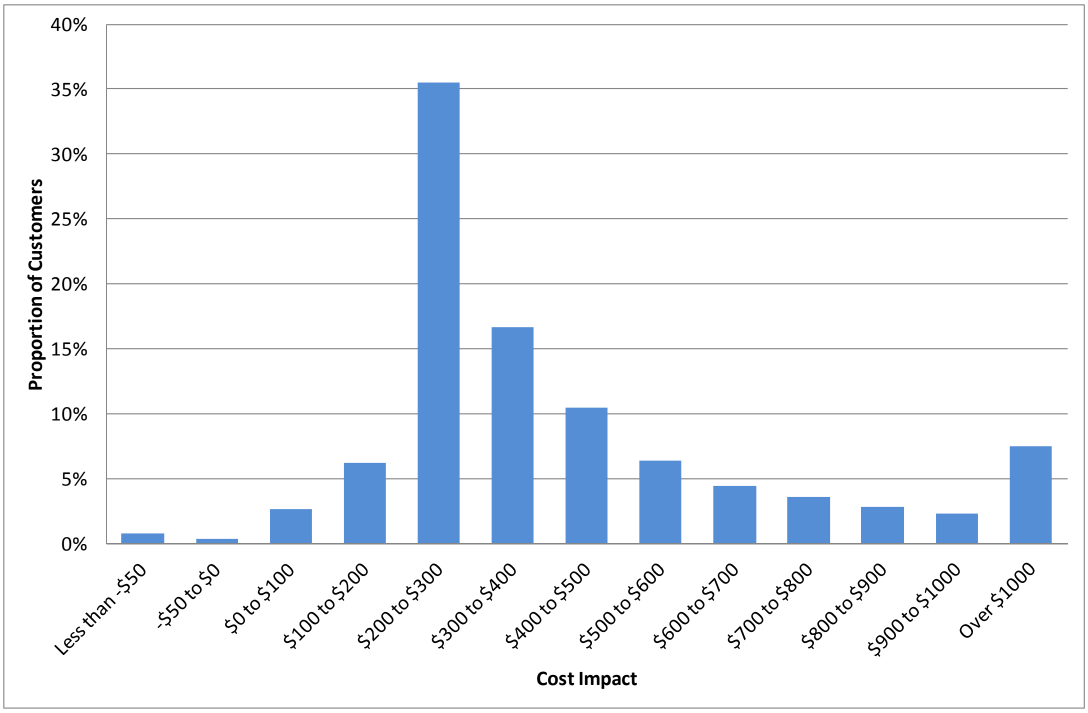
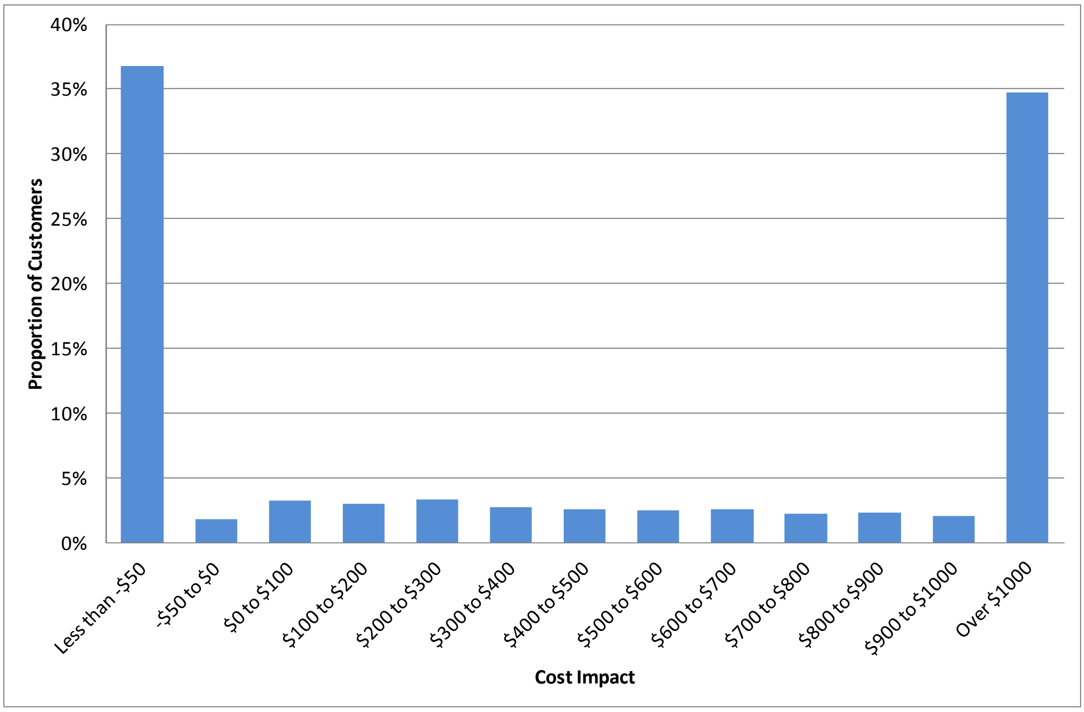


Figure C.5: Change in Electricity Bills in 2013-14 for Customers on Tariff 66



LARGE CUSTOMERS

Note that in calculating large customer impacts, Ergon Energy used a derived demand profile for customers where actual customer demand data was unavailable. As a result, Ergon indicated that cost impacts may be over- or understated. The figures for each tariff include impacts for customers that may also be on other tariffs.

Figure C.6: Change in Electricity Bills in 2013-14 for Customers on Tariff 20 (large)

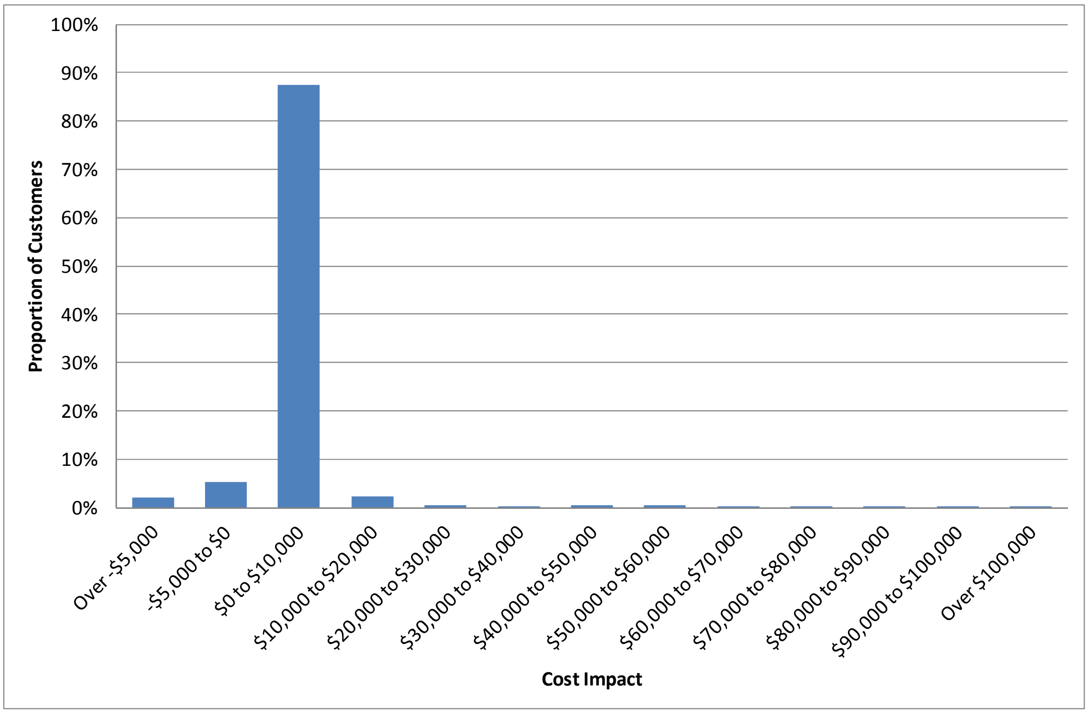


Figure C.7: Change in Electricity Bills in 2013-14 for Customers on Tariff 22 (large)

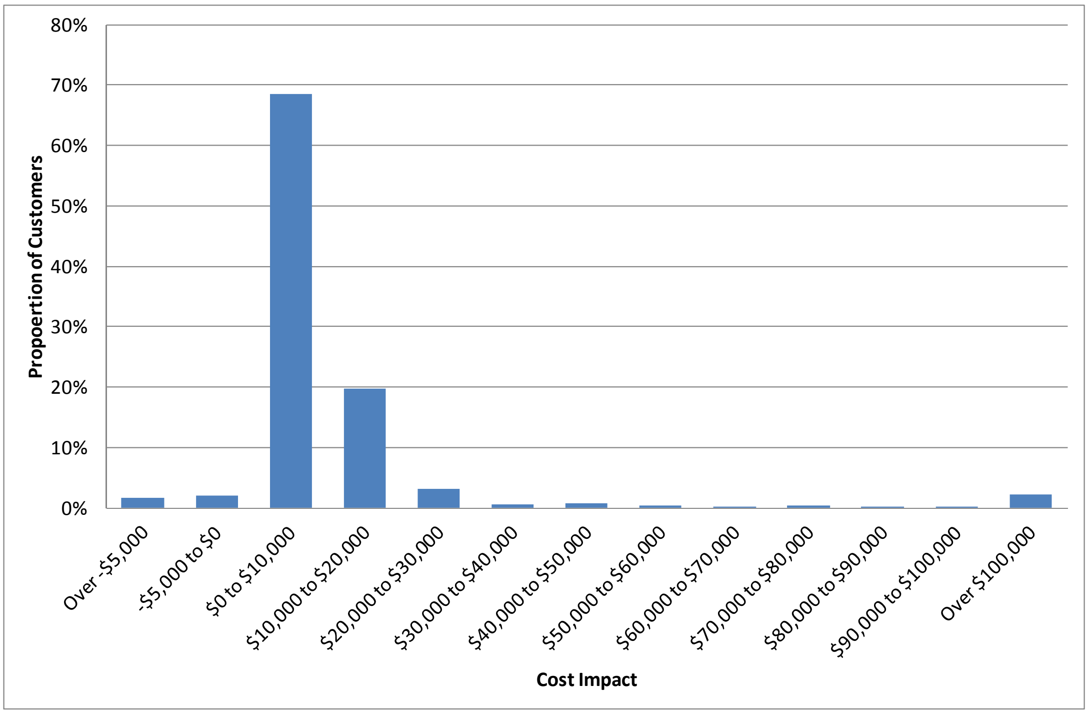


Figure C.8: Change in Electricity Bills in 2013-14 for Large Customers on Tariff 37

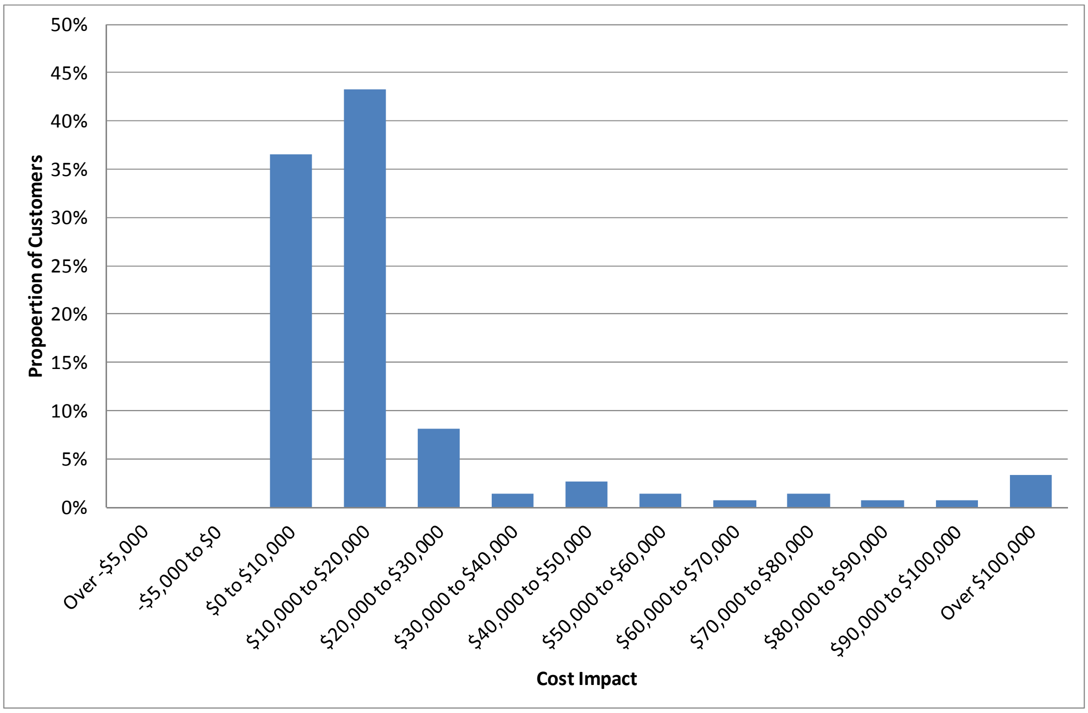


Figure C.9: Change in Electricity Bills in 2013-14 for Customers on Tariff 41 (large)

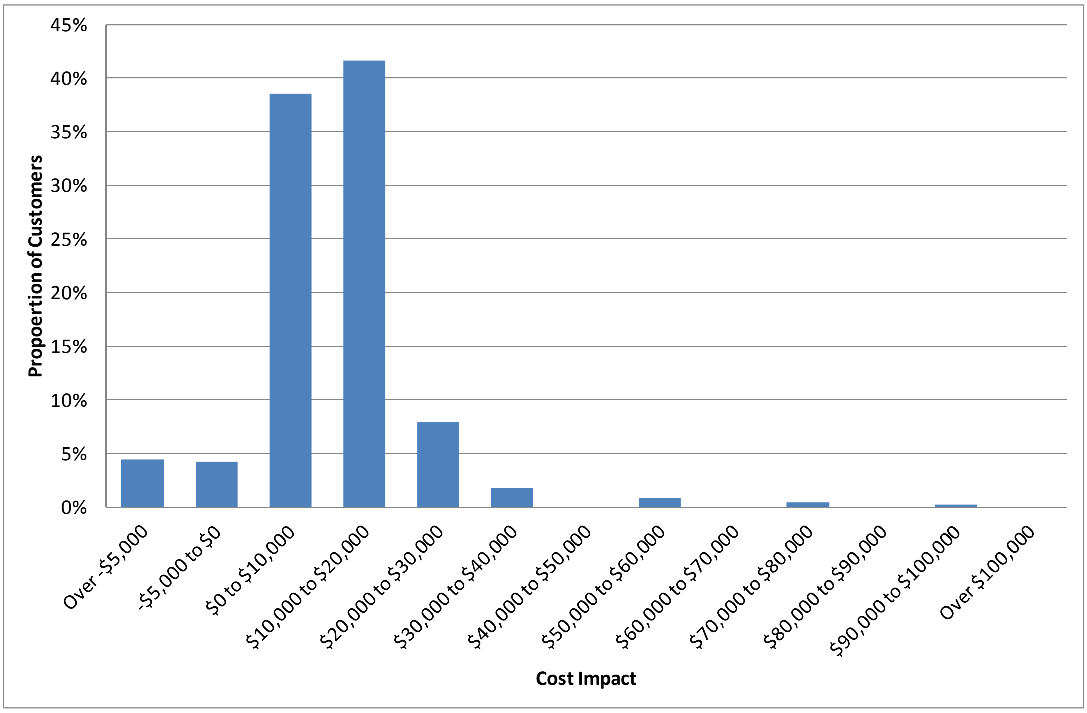


Figure C.10: Change in Electricity Bills in 2013-14 for Customers on Tariff 43 (large)

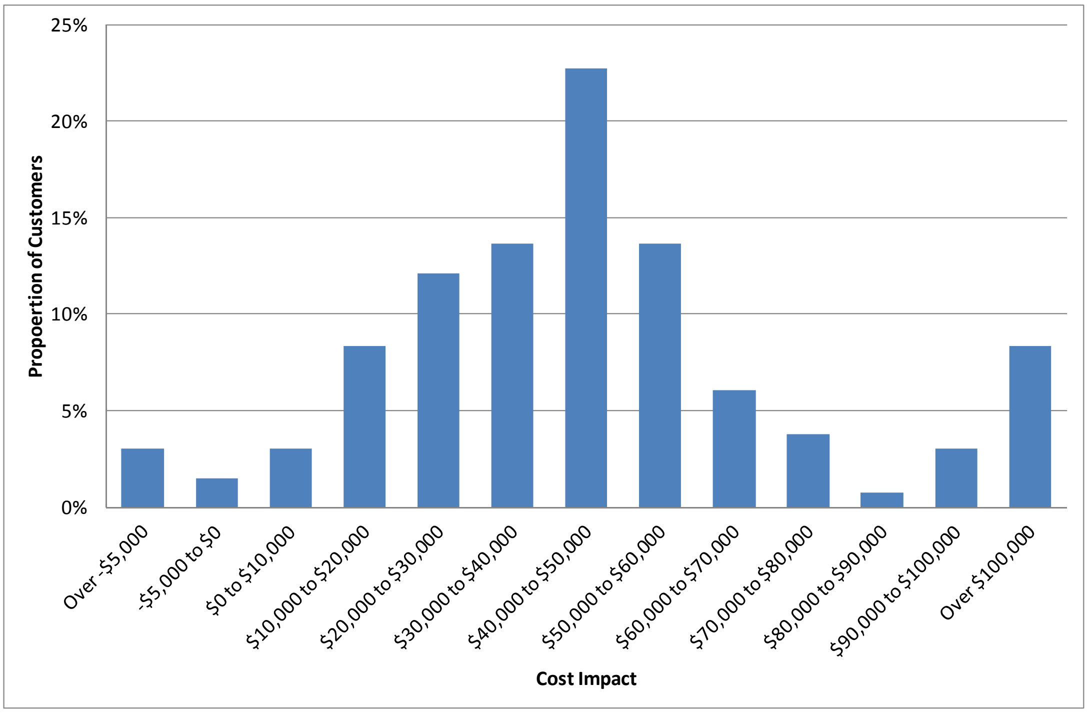


Figure C.11: Change in Electricity Bills in 2013-14 for Customers on Tariff 53 (large)

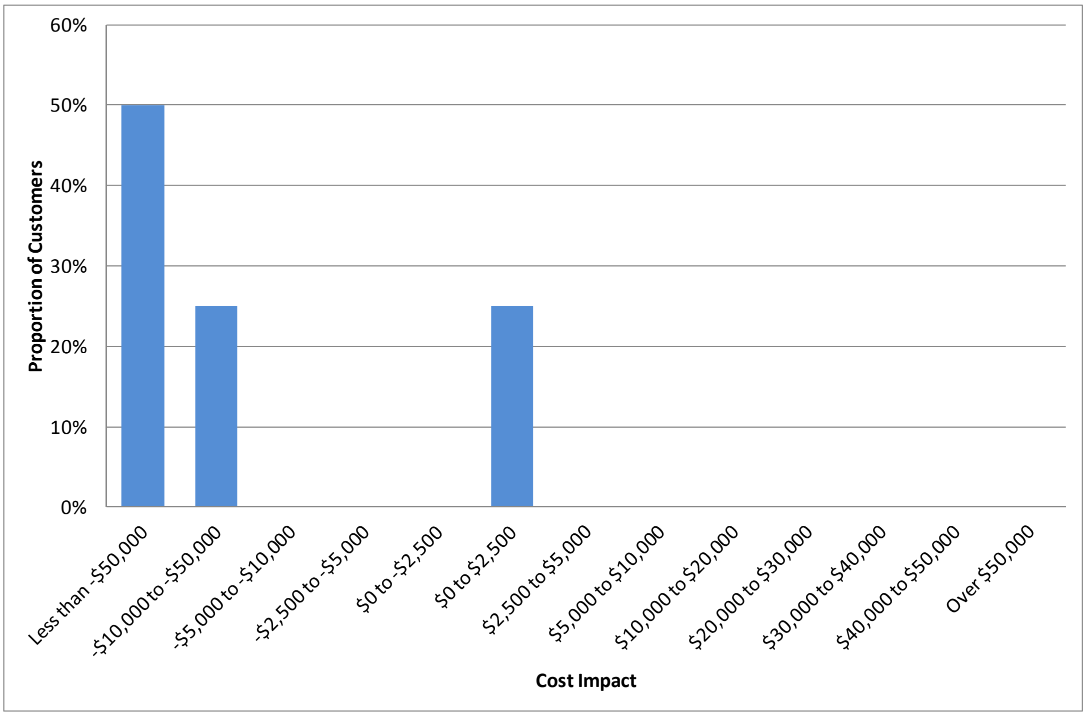


Figure C.12: Change in Electricity Bills in 2013-14 for Large Customers on Tariff 62

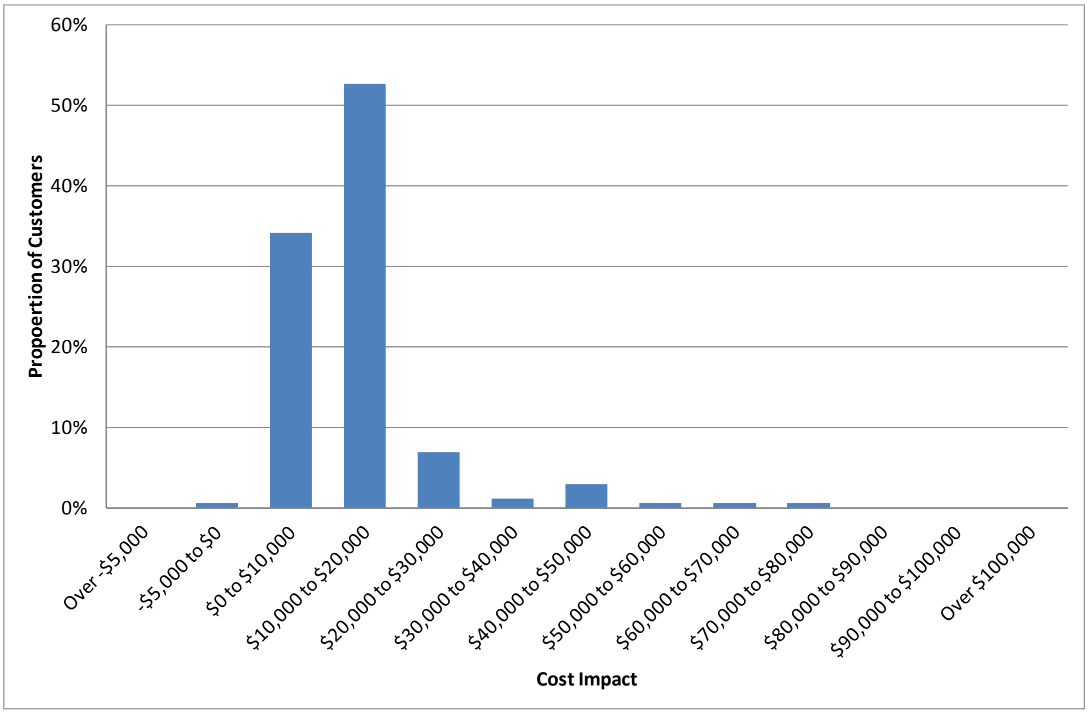


Figure C.13: Change in Electricity Bills in 2013-14 for Large Customers on Tariff 65

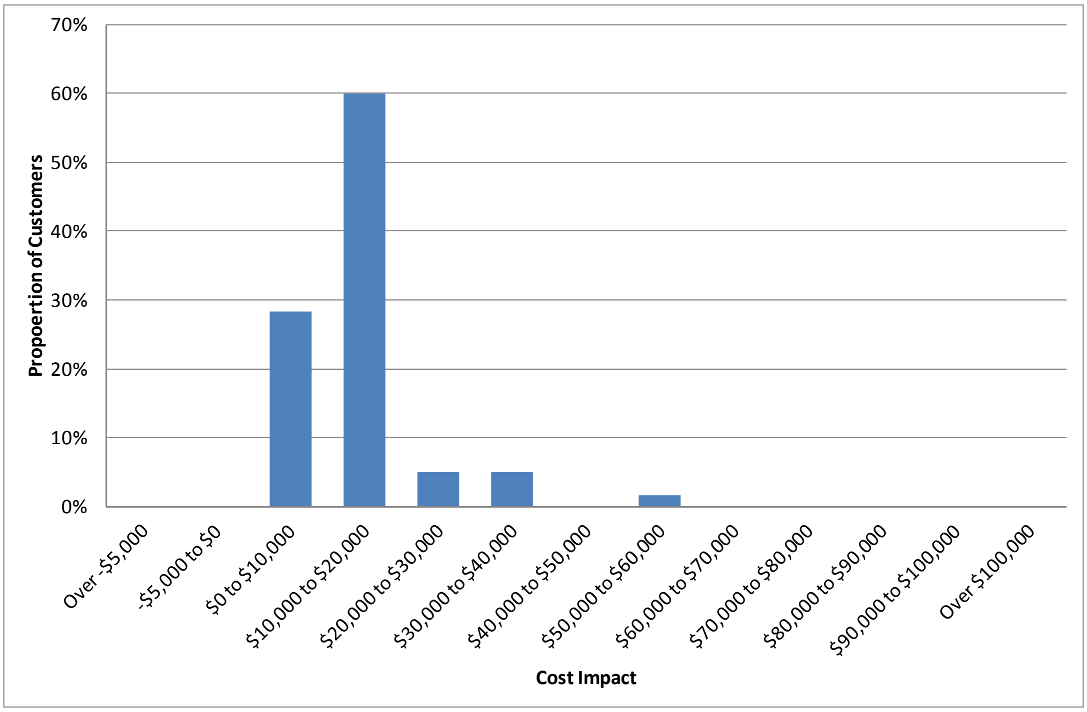
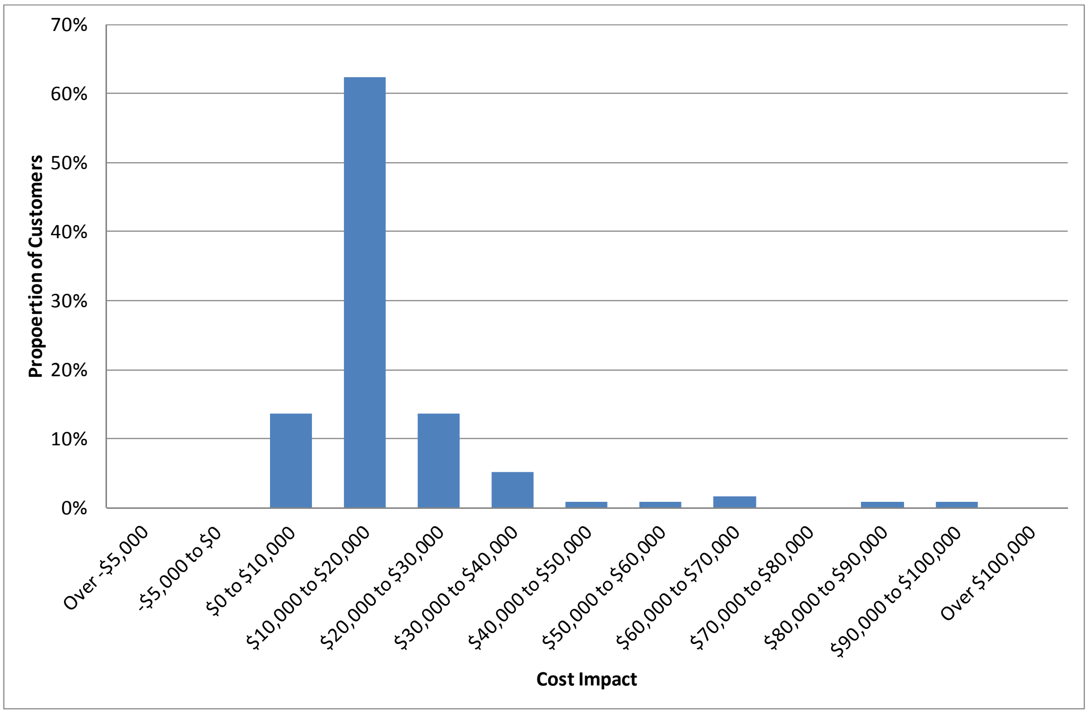


Figure C.14: Change in Electricity Bills in 2013-14 for Large Customers on Tariff 66



APPENDIX D: COST-REFLECTIVE RETAIL TARIFFS AND PRICES

Table D.1: Residential Regulated Retail Tariffs (GST Exclusive)

Retail tariff	*Tariff component*	*Fixed charge* [a]	*Variable rate (flat)*	*Variable rate 1 (off-peak)*	*Variable rate 2 (shoulder)*	*Variable rate 3 (peak)*
		c/day	*c/kWh*	*c/kWh*	*c/kWh*	*c/kWh*
Tariff 11 - Residential (flat rate)	Network	43.900	11.957			
	Energy		8.671			
	Retail	44.397				
	Margin	5.337	1.247			
	Headroom	4.682	1.094			
	Total [b]	*98.316*	*22.969*			
Tariff 12 - Residential (time of use)	Network	57.900		8.779	11.457	19.141
	Energy			8.671	8.671	8.671
	Retail	44.397				
	Margin	6.183		1.055	1.217	1.681
	Headroom	5.424		0.925	1.067	1.475
	Total [b]	*113.904*		*19.430*	*22.412*	*30.968*
Tariff 13 - Residential (PeakSmart)	Network	57.900		6.779	11.457	19.141
	Energy			8.671	8.671	8.671
	Retail	44.397				
	Margin	6.183		0.934	1.217	1.681
	Headroom	5.424		0.819	1.067	1.475
	Total [b]	*113.904*		*17.203*	*22.412*	*30.968*
Tariff 31 - Night rate (super economy)	Network		4.838			
	Energy		6.271			
	Retail					
	Margin		0.671			
	Headroom		0.589			
	Total [b]		*12.370*			
Tariff 33 - Controlled supply (economy)	Network		8.779			
	Energy		7.433			
	Retail					
	Margin		0.980			
	Headroom		0.860			
	Total [b]		*18.052*			

a. Charged per metering point.

b. Totals may not add due to rounding.

c. These are the cost-reflective charges. The transitional charges that customers will actually pay in 2013-14 are presented in Table 7.1 of Chapter 7.

Table D.2: Cost-Reflective 2013-14 Small Customer Regulated Retail Tariffs and Unmetered Supplies Other Than Street Lighting (GST Exclusive)

Retail tariff	*Tariff component*	*Fixed charge [a]* c/day	*Demand charge* $/kW/month	*Variable rate (flat)* c/kWh	*Variable rate (off-peak)* c/kWh	*Variable rate (peak)* c/kWh
Tariff 20 - Business (flat rate)	Network	72.500		12.181		
	Energy			8.671		
	Retail	44.397				
	Margin	7.066		1.260		
	Headroom	6.198		1.106		
	Total [b]	*130.161*		*23.218*		
Tariff 22 - Business (time of-use)	Network	72.500			8.095	14.227
	Energy				8.671	8.671
	Retail	44.397				
	Margin	7.066			1.013	1.384
	Headroom	6.198			0.889	1.214
	Total [b]	*130.161*			*18.668*	*25.496*
Tariff 41 - Low voltage (demand)	Network	677.200	20.887	1.439		
	Energy			8.671		
	Retail	44.397				
	Margin	43.617	1.263	0.611		
	Headroom	38.261	1.107	0.536		
	Total [b]	*803.475*	*23.257*	*11.257*		
Tariff 91 - Unmetered	Network			9.448		
	Energy			8.671		
	Retail					
	Margin			1.095		
	Headroom			0.961		
	Total [b]			*20.175*		

a. Charged per metering point.

b. Totals may not add due to rounding.

Table D.3: Cost-Reflective 2013-14 Large Customer Regulated Retail Tariffs and Street Lighting (GST Exclusive)

Retail tariff	*Tariff component*	*Fixed charge* [a] *c/day*	*Demand charge* *$/kW/month*	*Variable rate (flat)* *c/kWh*
Tariff 44 - Over 100 MWh small (demand)	Network	582.600	31.682	1.913
	Energy			8.565
	Retail	196.788		
	Margin	47.110	1.915	0.633
	Headroom	41.325	1.680	0.556
	Total [b]	867.823	35.277	11.667
Tariff 45 - Over 100 MWh medium (demand)	Network	2,235.400	27.486	1.913
	Energy			8.565
	Retail	196.788		
	Margin	147.015	1.661	0.633
	Headroom	128.960	1.457	0.556
	Total [b]	2,708.163	30.605	11.667
Tariff 46 - Over 100 MWh large (demand)	Network	3,642.700	26.416	1.913
	Energy			8.565
	Retail	196.788		
	Margin	232.079	1.597	0.633
	Headroom	203.578	1.401	0.556
	Total [b]	4,275.146	29.413	11.667
Tariff 47 - High voltage (demand)	Network	2,306.200	21.109	1.853
	Energy			8.210
	Retail	196.788		
	Margin	151.294	1.276	0.608
	Headroom	132.714	1.119	0.534
	Total [b]	2,786.996	23.504	11.205
Tariff 48 – Over 4 GWh High voltage (demand)	Network	2,306.200	21.109	1.853
	Energy			8.210
	Retail	561.607		
	Margin	173.346	1.276	0.608
	Headroom	152.058	1.119	0.534
	Total [b]	3,193.210	23.504	11.205
Tariff 71 - Street lighting [c]	Network	0.600	0.000	23.435
	Energy			8.565
	Retail			
	Margin	0.036	0.000	1.934
	Headroom	0.032	0.000	1.697
	Total [b]	0.668	0.000	35.631

a. Charged per metering point.

b. Totals may not add due to rounding.

c. The fixed charge for street lighting applies to each lamp.

APPENDIX E: TARIFF SCHEDULE

Queensland Government Gazette

RETAIL ELECTRICITY PRICES FOR CUSTOMERS ON STANDARD RETAIL CONTRACTS AND STANDARD LARGE CUSTOMER RETAIL CONTRACTS

Electricity Act 1994

Pursuant to the Certificate of Delegation from the Minister for Energy and Water Supply (dated 12 February 2013) and sections 90(2) and 90AB of the *Electricity Act 1994* (the Electricity Act), I hereby state that the Queensland Competition Authority decided that, on and from 1 July 2013, the notified prices that a retail entity must charge its customers on a Standard Retail Contract or Standard Large Customer Retail Contract (also referred to as a Standard Retail Contract), subject to the provisions of sections 55, 90, 91 and 91A of the Electricity Act, are the applicable prices set out in the attached Tariff Schedule or, as the case may be, the prices obtained by applying the applicable methodology or process set out in the attached Tariff Schedule.

This Tariff Schedule does not apply to customers on a Standard Retail Contract supplied under Origin Energy Electricity Limited's Special Approval number SA02/11 (being customers on a Standard Retail Contract connected to Essential Energy's New South Wales network which extends into southern Queensland). Under the terms of the Special Approval, these customers will generally pay no more for electricity than other Queensland customers on a Standard Retail Contract of similar usage categories or classes.

The Tariff Schedule does not apply to customers in Energex Limited's distribution area who consume 100 megawatt hours (MWh) per annum or more, unless the customer is classified as residential. For a residential customer, including a residential body corporate, there is no maximum consumption threshold. From 1 July 2012, business (non-residential) customers in the Energex distribution area who consume 100 MWh per annum or more do not have access to notified prices.

Eligible customers may access the transitional tariffs in Part 2 of the Tariff Schedule. These tariffs will be available for a set period of time as a transitional measure to assist customers in moving to the alternate cost-reflective tariffs in the future. Customers on the transitional tariffs may opt to transfer to the new cost-reflective tariffs in Part 1 of the Tariff Schedule at any time.

As required by section 90AB(4) of the Electricity Act, the notified prices are exclusive of the goods and services tax ('GST') payable under the *A New Tax System (Goods and Services Tax) Act 1999* (Cth) ('the GST Act').

In addition to the applicable tariff, a retail entity may charge a customer on a Standard Retail Contract an additional amount in accordance with a program or scheme for the purchase of electricity from renewable or environmentally-friendly sources (whether or not that additional amount is calculated on the basis of the customer's electricity consumption), but only if –

(A) the customer voluntarily participates in such program or scheme;

(B) the retail entity has obtained the customer's consent (as defined in the Electricity Industry Code) to charge the customer an additional amount (and whether such amount is inclusive or exclusive of GST), provided that if a customer is participating in such a program or scheme at 30 June 2013 the customer is taken to have provided explicit informed consent for the retail entity to charge the customer the additional amount payable under the program or scheme; and

(C) the retail entity gives the customer prior written notice of any change to the additional amount payable under the program or scheme.

Dated this 31st day of May 2013.

Dr Malcolm Roberts, Chairman
Queensland Competition Authority

Note 1: For the purposes of sections 55, 90, 91 and 91A of the Electricity Act, the tariffs and other retail fees and charges in this Tariff Schedule are exclusive of GST payable under the GST Act.

Note 2: This Tariff Schedule replaces the Tariff Schedule published in the Queensland Government Gazette on 29 June 2012.

Note 3: This Tariff Schedule is structured in several Parts:

Parts 1 to 5 (inclusive) apply to customers on a Standard Retail Contract and customers on a Standard Large Customer Retail Contract of Ergon Energy Queensland Pty Ltd.

Part 6 applies to eligible customers on a Standard Retail Contract of Ergon Energy Queensland Pty Ltd. Eligible customers on a Standard Retail Contract of other retail entities may apply directly to the Department of Energy and Water Supply for relief from electricity charges if a drought declaration is in force – see Part 6 for more detail.

Note 4: 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 4 (Application of Tariffs for Customers on Notified Prices – General).

Note 5: Any reference in this Tariff Schedule to a time is a reference to Eastern Standard Time.

Note 6: "NMI" means the National Metering Identifier and is applicable to the point at which a premises is connected to a distribution entity's network.

Note 7: A primary tariff is the tariff that reflects the primary use of the premises or the majority of the load, and is capable of existing by itself against a NMI. A secondary tariff is any other tariff.

Note 8: Only days that supply is connected are to be counted for billing of charges.

Note 9: A service fee is a fixed amount charged monthly to cover the costs of maintaining electricity supply to a premise, including the costs associated with electricity meter reading, the provision of equipment and general administration. Retailers may use different terms for this charge, including Service Charge, Daily Supply Charge and Service to Property Charge.

Note 10: Unless otherwise defined, the terminology used in this Tariff Schedule is intended to be consistent with the energy laws.

Part 1

TARIFFS FOR RESIDENTIAL, COMMERCIAL AND RURAL APPLICATIONS

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

This tariff is applicable to a customer who is classified as residential by the relevant retail entity and can be accessed by a small business customer providing it is in conjunction with a primary business tariff (Tariff 20, 21, 22, 41, 62, 65 or 66) at the same NMI.

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

This tariff cannot be used in conjunction with Tariff 12 (Residential) (Time-of-Use) or Tariff 13 (Residential) (PeakSmart – Time-of-Use) at the same NMI.

Where a NMI has multiple meters, the consumption for all meters that record consumption for Tariff 11 will be aggregated for billing purposes.

No large business customers are eligible for this tariff.

All Consumption	**26.730 c/kWh**
plus a Service Fee per metering point per day of	**50.219 c**

Further applications of this tariff are described in Part 4 (Application of Tariffs for Customers on Notified Prices – General) and Part 5 (Concessional Applications of Tariffs 11, 12 and 13 (Residential)).

***Tariff 12* – Residential (Lighting, Power and Continuous Water Heating) (Time-of-Use) –**

This tariff is applicable to a customer who is classified as residential by the relevant retail entity and can be accessed by a small business customer providing it is in conjunction with a primary business tariff (Tariff 20, 21, 22, 41, 62, 65 or 66) at the same NMI.

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

This tariff cannot be used in conjunction with Tariff 11 (Residential) or Tariff 13 (Residential) (PeakSmart –Time-of-Use) at the same NMI.

Where a NMI has multiple meters, the consumption for all meters that record consumption for Tariff 12 will be aggregated for billing purposes.

No large business customers are eligible for this tariff.

Customers must have the appropriate metering installed in order to access this tariff.

All consumption

Weekdays:

Off-Peak (10pm-7am)	**19.430 c/kWh**
Shoulder (7am-4pm), (8pm-10pm)	**22.412 c/kWh**
Peak (4pm-8pm)	**30.968 c/kWh**

Weekends:

Off-Peak (10pm-7am)	**19.430 c/kWh**
Shoulder (7am-10pm)	**22.412 c/kWh**

plus a Service Fee per metering point per day of **113.904 c**

Further applications of this tariff are described in Part 4 (Application of Tariffs for Customers on Notified Prices – General) and Part 5 (Concessional Applications of Tariffs 11, 12 and 13 (Residential)).

Tariff 13 – Residential (Lighting, Power and Continuous Water Heating) (PeakSmart Time-of-Use) –

This tariff is applicable to a customer who is classified as residential by the relevant retail entity and can be accessed by a small business customer providing it is in conjunction with a primary business tariff (Tariff 20, 21, 22, 41, 62, 65 or 66) at the same NMI.

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

This tariff cannot be used in conjunction with Tariff 11 (Residential) or Tariff 12 (Residential) (Time-of-Use) at the same NMI.

This tariff is only available to customers who have a total of at least 4kW cooling capacity (or equivalent rated input load) at the NMI that is under demand management by the applicable distribution entity, including at least one activated PeakSmart Air-Conditioning Unit (connected with a signal receiver).

A 'PeakSmart Air-Conditioning Unit' means an air-conditioning system with functionality added by the manufacturer that meets all specific criteria as indicated in the Australian Standard AS4755.3.1, 'Interaction of demand response enabling devices and electricity products – Operational instructions and connections for air conditioners.'

Under this tariff, supply will be available to the premise at all times; however, demand management of PeakSmart Air Conditioning units is variable and will be managed at the absolute discretion of the distribution entity.

Periodic validation of system compliance may be required and will be undertaken at the absolute discretion of the distribution entity.

This tariff is available at the absolute discretion of the distribution entity. If this tariff becomes unavailable in future years, customers on this tariff will automatically be transferred to Tariff 12, unless the customer contacts their retailer to request they are transferred to an alternative tariff for which they are eligible.

Where a NMI has multiple meters, the consumption for all meters that record consumption for Tariff 13 will be aggregated for billing purposes.

No large business customers are eligible for this tariff.

Customers must have the appropriate metering installed in order to access this tariff.

All consumption

Weekdays:

Off-Peak (10pm-7am)	**17.203 c/kWh**
Shoulder (7am-4pm), (8pm-10pm)	**22.412 c/kWh**
Peak (4pm-8pm)	**30.968 c/kWh**

Weekends:

Off-Peak (10pm-7am)	**17.203 c/kWh**
Shoulder (7am-10pm)	**22.412 c/kWh**

plus a Service Fee per metering point per day of **113.904 c**

Further applications of this tariff are described in Part 4 (Application of Tariffs for Customers on Notified Prices – General) and Part 5 (Concessional Applications of Tariffs 11, 12 and 13 (Residential)).

***Tariff 20* – Business General Supply –**

This tariff can not be accessed by large business customers. Refer Part 2 for transitional tariffs for large business customers.

Residential customers can access this tariff providing:

- the electricity is used in separately metered common sections of residential premises consisting of more than one flat or home unit; or
- it is in conjunction with a primary residential tariff at the same NMI.

All Consumption **23.218 c/kWh**

plus a Service Fee per metering point per day of **130.161 c**

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

This tariff can not be accessed by large business customers. Refer Part 2 for transitional tariffs for existing large business customers.

Residential customers can access this tariff providing:

- the electricity is used in separately metered common sections of residential premises consisting of more than one flat or home unit; or
- it is in conjunction with a primary residential tariff at the same NMI.

Customers must have the appropriate metering installed in order to access this tariff.

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

All Consumption **25.496 c/kWh**

For electricity consumed at other times -

All Consumption **18.668 c/kWh**

plus a Service Fee per metering point per day of **130.161 c**

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

Eligible customers can access this tariff providing it is in conjunction with a residential or business tariff at the same NMI at the discretion of the distribution entity.

This tariff is not available to large business customers in Ergon Energy Corporation Limited's distribution area.

This tariff is applicable when electricity supply is:
- permanently connected to apparatus; or
- connected to apparatus by means of a socket-outlet as approved by the distribution entity; or
- permanently connected to specified parts of apparatus;

as set out below (but not applicable, except as described in (c) below, if provision has been made to supply such apparatus or the specified part thereof under a different tariff during the restricted period) -

(a) Electric storage water heaters with thermostatically controlled or continuously operating heating units and which comply with the construction and performance requirements of Australian Standard 1361 or 1056 or previous Standards superseded by these two Standards or similar electric water heaters which are approved for connection by the distribution entity.

Where the heating unit rating exceeds 1,800 watts, it shall not exceed 13.5 watts per litre of heat storage volume for heat exchange type water heaters or 15.5 watts per litre of rated hot water delivery for other storage type water heaters.

The following conditions shall apply to any booster heating unit fitted -

(i) its rating shall not exceed that of the main heating unit;

(ii) it shall be connected so as to prevent it being energised simultaneously with the main heating unit;

(iii) electricity consumed by the booster heating unit shall be metered under and charged at the tariff applicable to general power usage at the premises concerned;

(iv) it shall be located in accordance with the provisions of the above Standards.

(b) Solar-heated water heaters. Where the electric heating unit rating exceeds 1,800 watts, it shall not exceed 13.5 watts per litre of storage tank capacity. If a circulating water pump is fitted to the system, continuous supply will be available to the pump, and electricity consumed shall be metered under and charged at the tariff applicable to general power usage at the premises concerned.

(c) One-shot boost for solar-heated water heaters with electric heating units as described in (b) above. A current held changeover relay may be fitted to the water heater to deliver, at the customer's convenience, a 'one-shot boost' supply to the electric heating element at times when supply is not available under this Tariff 31 (generally between the hours of 7.00 am and 10.00 pm). Such supply is subject to thermostatically controlled switchoff. Electricity consumed during operation of the one-shot boost shall be metered under and charged at the tariff applicable to general power usage at the premises concerned. Supply and installation of a current held changeover relay, including the cost of same, is the responsibility of the customer.

(Reference in this Tariff Schedule to a 'booster heating unit' does not mean a current held changeover relay which is capable of delivering a 'one-shot boost'.)

(d) Heat pump 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 it 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.

The distribution entity will provide and install the load control equipment at its cost. Additional charges may apply for other distribution services associated with the load control equipment, where the costs of the requested service are not included in the distribution entity's network charges.

Supply will be available for a minimum of 8 hours per day, but the times when supply is available is subject to variation at the absolute discretion of the distribution entity. In general, this supply will be between the hours of 10.00 pm and 7.00 am.

All Consumption **12.370 c/kWh**

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

Eligible customers can access this tariff providing it is in conjunction with a residential or business tariff at the same NMI at the discretion of the distribution entity.

This tariff is not available to large business customers in Ergon Energy Corporation Limited's distribution area.

This tariff is applicable when electricity supply is:

(a) connected to apparatus (e.g. pool filtration system) by means of a socket-outlet as approved by the distribution entity; or

(b) permanently connected to apparatus as set out below (but not applicable if provision has been made to supply such apparatus under a different tariff in the periods during which supply is not available under this tariff) –

(i) Electric storage water heaters with thermostatically controlled or continuously operating heating units and which comply with the construction and performance requirements of Australian Standard 1361 or 1056 or previous Standards superseded by these two Standards or similar electric water heaters which are approved for connection by the distribution entity.

Where the heating unit rating exceeds 1,800 watts, it shall not exceed 13.5 watts per litre of heat storage volume for heat exchange type water heaters or 15.5 watts per litre of rated hot water delivery for other storage type water heaters.

(ii) Solar-heated water heaters. Where the electric heating unit rating exceeds 1,800 watts, it shall not exceed 13.5 watts per litre of storage tank capacity.

(iii) Heat pump 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 at the absolute discretion of the distribution entity.

(v) Other individual loads in domestic installations, but is not applicable –

- to arc or resistance welding plant;
- where the apparatus is duplicated in order that supply may be obtained on a different tariff for the same purpose during the restricted period.

The distribution entity will provide and install the load control equipment at its cost. Additional charges may apply for other distribution services associated with the load control equipment, where the costs of the requested service are not included in the distribution entity's network charges.

Supply will be available for a minimum of 18 hours per day, but the times when supply is available is subject to variation at the absolute discretion of the distribution entity.

All Consumption **18.052 c/kWh**

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

This tariff will be retained for a period of no more than seven years from 1 July 2013. 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 **44.410 c/kWh**

For electricity consumed between the hours of 10.30 pm and 4.30 pm **17.755 c/kWh**

Minimum Payment per day of **24.932 c**

***Tariff 41* – Business Low Voltage General Supply (Demand) –**

This tariff can not be accessed by large business customers. Refer Part 2 for transitional tariffs for large business customers.

Demand Charge –

$23.257 per kilowatt per month of chargeable demand.

Energy Charge –

All Consumption **11.257 c/kWh**

plus a Service Fee per metering point per day of **803.475 c**

The chargeable demand in any month shall be the maximum demand recorded in that month.

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

Customers must have the appropriate metering installed in order to access this tariff.

***Tariff 41 (Large)* – Business Low Voltage General Supply (Demand) (Obsolescent) –**

No new customers will be supplied under this tariff. It is available only to large business customers in Ergon Energy Corporation Limited's distribution area taking supply under Tariff 41 at 30 June 2012. This tariff will only be available until 30 June 2015.

Demand Charge -

$46.840 per kilowatt per month of chargeable demand.

Energy Charge -

All Consumption **9.848 c/kWh**

plus a Service Fee per metering point per day of **219.231 c**

The chargeable demand in any month shall be –
(a) the maximum demand recorded in that month; or
(b) 60 per cent 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 NMI.

***Tariff 43 (Large)* – General Supply Demand – Time-of-Use (Obsolescent) –**

No new customers will be supplied under this tariff. It is available only to large business customers in Ergon Energy Corporation Limited's distribution area taking supply under Tariff 43 at 30 June 2012. This tariff will only be available until 30 June 2015.

Demand Charge –

$20.286 per kilowatt per month of chargeable demand.

Energy Charge –

For electricity consumed between the hours of 7.00am and 11.00pm, Monday to Friday inclusive -

All Consumption **20.039 c/kWh**

For electricity consumed at other times –

All Consumption **8.010 c/kWh**

plus a Service Fee per metering point per day of **219.231 c**

The chargeable demand in any month shall be –
(a) the maximum demand recorded in that month; or
(b) 60 per cent 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 must have the appropriate metering installed in order to access this tariff.

***Tariff 44* – Business Over 100MWh (Demand Small) – Ergon Energy Corporation Limited distribution area ONLY –**

This tariff will be available to Ergon Energy Queensland Pty Ltd customers.

This tariff can be accessed by business customers classified as SAC >100MWh per annum by the distribution entity. The tariff is based on the Ergon Energy Corporation Limited network tariff of Demand Small.

A Standard Asset Customer (SAC) is a large business customer in Ergon Energy Corporation Limited's distribution area whose annual energy consumption generally exceeds 100MWh.

This tariff cannot be used in conjunction with any other tariff at that NMI.

Demand Charge –

$35.277 per kilowatt per month of chargeable demand.

Energy Charge –

All Consumption **11.667 c/kWh**

plus a Service Fee per metering point per day of **867.823 c**

The chargeable demand in any month shall be the maximum demand recorded in that month with a minimum chargeable demand of 30kW to apply.

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

Customers must have the appropriate metering installed in order to access this tariff.

***Tariff 45* – Business Over 100MWh (Demand Medium) – Ergon Energy Corporation Limited distribution area ONLY –**

This tariff will be available to Ergon Energy Queensland Pty Ltd customers.

This tariff can be accessed by business customers classified as SAC >100MWh per annum by the distribution entity. The tariff is based on the Ergon Energy Corporation Limited network tariff of Demand Medium.

A Standard Asset Customer (SAC) is a large business customer in Ergon Energy Corporation Limited's distribution area whose annual energy consumption generally exceeds 100MWh.

This tariff cannot be used in conjunction with any other tariff at that NMI

Demand Charge –

$30.605 per kilowatt per month of chargeable demand.

Energy Charge –

All Consumption **11.667 c/kWh**

plus a Service Fee per metering point per day of **2,708.163 c**

The chargeable demand in any month shall be the maximum demand recorded in that month with a minimum chargeable demand of 120kW to apply.

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

Customers must have the appropriate metering installed in order to access this tariff.

***Tariff 46* – Business Over 100MWh (Demand Large) – Ergon Energy Corporation Limited distribution area ONLY –**

This tariff will be available to Ergon Energy Queensland Pty Ltd customers.

This tariff can be accessed by business customers classified as SAC >100MWh per annum by the distribution entity. The tariff is based on the Ergon Energy Corporation Limited network tariff of Demand Large.

A Standard Asset Customer (SAC) is a large business customer in Ergon Energy Corporation Limited's distribution area whose annual energy consumption generally exceeds 100MWh.

This tariff cannot be used in conjunction with any other tariff at that NMI

Demand Charge –

$29.413 per kilowatt per month of chargeable demand.

Energy Charge –

All Consumption **11.667 c/kWh**

plus a Service Fee per metering point per day of **4,275.146 c**

The chargeable demand in any month shall be the maximum demand recorded in that month with a minimum chargeable demand of 400kW.

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

Customers must have the appropriate metering installed in order to access this tariff.

***Tariff 47* – Business - High Voltage General Supply (Demand) – Ergon Energy Corporation Limited distribution area ONLY –**

This tariff will be available to Ergon Energy Queensland Pty Ltd customers.

This tariff can be accessed by business customers classified as SAC >100MWh per annum by the distribution entity. The tariff is based on the Ergon

Energy Corporation Limited network tariff of Demand High Voltage.

A Standard Asset Customer (SAC) is a large business customer in Ergon Energy Corporation Limited's distribution area whose annual energy consumption generally exceeds 100MWh.

This tariff cannot be used in conjunction with any other tariff at that NMI.

This tariff cannot be accessed by business customers who are classified as Connection Asset Customers or Individually Calculated Customers by the distribution entity.

Demand Charge –

$23.504 per kilowatt per month of chargeable demand.

Energy Charge –

All Consumption **11.205 c/kWh**

plus a Service Fee per metering point per day of **2,786.996 c**

The chargeable demand in any month shall be the maximum demand recorded in that month with a minimum chargeable demand of 400kW.

'Demand' shall mean the average demand in kilowatts over a period of 30 minutes, as measured on the distribution entity's meters. Supply under this tariff will be at a standard high voltage, the level of which shall be prescribed by the distribution entity. Credits for high voltage supply are not applicable to this tariff.

Customers must have the appropriate metering installed in order to access this tariff.

***Tariff 48* – Business - General Supply (>4 Gigawatt Hours (GWh)) (Demand) – Ergon Energy Corporation Limited distribution area ONLY –**

This tariff will be available to Ergon Energy Queensland Pty Ltd customers.

This tariff can only be accessed by business customers who are classified as Connection Asset Customers or Individually Calculated Customers by the distribution entity. The tariff is based on the Ergon Energy Corporation Limited network tariff of Demand High Voltage.

A Connection Asset Customer is a large business customer in Ergon Energy Corporation Limited's distribution area whose annual energy consumption generally exceeds 4GWh.

An Individually Calculated Customer is a large business customer in Ergon Energy Corporation Limited's distribution area whose annual energy consumption generally exceeds 40GWh.

Demand Charge –

$23.504 per kilowatt per month of chargeable demand.

Energy Charge –

All Consumption **11.205 c/kWh**

plus a Service Fee per metering point per day of **3,193.210 c**

The chargeable demand in any month shall be the maximum demand recorded in that month with a minimum chargeable demand of 400kW.

'Demand' shall mean the average demand in kilowatts over a period of 30 minutes, as measured on the distribution entity's meters. Credits for high voltage supply are not applicable to this tariff.

Customers must have the appropriate metering installed in order to access this tariff.

Part 2

TRANSITIONAL TARIFFS FOR NEW AND EXISTING CUSTOMERS

The following tariffs are available as a transitional measure to assist new and existing customers in moving to alternate cost-reflective tariffs in the future. Transitional tariffs will be retained for a period of no more than seven years from 1 July 2013.

***Tariff 20 (Large)* – Business General Supply (Transitional) –**

This transitional tariff will be retained for a period of no more than seven years from 1 July 2013, and will be available to large business customers in Ergon Energy Corporation Limited's distribution area.

This tariff cannot be accessed by small business or residential customers.

All Consumption **29.157 c/kWh**

plus a Service Fee per metering point per day of **59.606 c**

***Tariff 21* – Business General Supply (Transitional) –**

This transitional tariff will be retained for a period of no more than seven years from 1 July 2013.

This tariff can only be accessed by a residential customer if it is in conjunction with a primary residential tariff at the same NMI.

This tariff shall not apply in conjunction with Tariff 20, 22 or 62.

First 100 kilowatt hours per month	**42.854 c/kWh**
Next 9,900 kilowatt hours per month	**40.265 c/kWh**
Remaining kilowatt hours per month	**30.653 c/kWh**
plus a Minimum Payment per day of	**63.064 c**

***Tariff 22 (Small and Large)* – Business General Supply – Time-of-Use (Transitional) –**

This transitional tariff will be retained for a period of no more than seven years from 1 July 2013.

This tariff can only be accessed by a residential customer if it is in conjunction with a primary residential tariff at the same NMI.

Customers must have the appropriate metering installed in order to access this tariff.

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

All Consumption **39.297 c/kWh**

For electricity consumed at other times -

All Consumption **13.838 c/kWh**

plus a Service Fee per metering point per day of **145.698 c**

***Tariff 62* - Farm - Time-of-Use (Transitional) -**

This transitional tariff will be retained for a period of no more than seven years from 1 July 2013.

This tariff can only be accessed by a residential customer if it is in conjunction with a primary residential tariff at the same NMI.

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

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	**39.085 c/kWh**
Remaining kilowatt hours	**33.053 c/kWh**

For electricity consumed at other times -

All Consumption **13.820 c/kWh**

plus a Service Fee per metering point per day of **65.918 c**

***Tariff 65* - Irrigation - Time-of-Use (Transitional) -**

This transitional tariff will be retained for a period of no more than seven years from 1 July 2013.

This tariff can only be accessed by a residential customer if it is in conjunction with a primary residential tariff at the same NMI.

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 **31.178 c/kWh**

For electricity consumed at other times –

All Consumption **17.173 c/kWh**

plus a Service Fee per metering point per day of **65.918 c**

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 (Transitional) –**

This transitional tariff will be retained for a period of no more than seven years from 1 July 2013.

This tariff can only be accessed by a residential customer if it is in conjunction with a primary residential tariff at the same NMI.

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

First 7.5 kilowatts	$**31.693** per kW
Remaining kilowatts	$**95.291** per kW

Energy Charge –

All Consumption **16.342 c/kWh**

plus a Service Fee per metering point per day of **145.282 c**

Minimum Annual Fixed Charge - As calculated for 7.5 kW (Note – 7.5 kW is equivalent to 10.05 h.p.)

Any customer taking supply under this tariff who requests a temporary disconnection will not be reconnected unless the outstanding balance of the Annual Fixed Charge for part of the year corresponding to the period of disconnection has been paid.

Part 3

TARIFFS FOR UNMETERED SUPPLY INCLUDING STREET LIGHTS, TRAFFIC SIGNALS, WATCHMAN LIGHTING AND TEMPORARY SERVICES

Tariff 71 **– Street Lights –**

Notified prices for Tariff 71, published in accordance with section 90 of the Electricity Act, will only apply in Ergon Energy Corporation Limited's distribution area. The *Electricity Regulation Amendment (No.1) 2008* provides that, from 1 July 2008, street lighting customers in Energex Limited's distribution area will be defined as market customers and so will not have access to the notified prices.

Street lighting customers are as defined in Queensland legislative instruments, being State or local government agencies for street lighting loads.

Street lights are deemed to illuminate roads. In Queensland, there are two main types of roads, being:

- Local government roads – roads for which a local government has control. These roads comprise land that is:
  - dedicated to public use as a road; or
  - developed for (or has as one of its main uses) the driving or riding of motor vehicles and is open to, or used by, the public;
  - a footpath or bicycle path; or
  - a bridge, culvert, ford, tunnel or viaduct,

  and excludes State-controlled roads and public thoroughfare easements; and
- **State-controlled roads** – roads that are declared under the *Transport Infrastructure Act 1994* (Qld) to be a State-controlled road, for which the relevant Minister for that Act has control (i.e. of the Department of Transport and Main Roads).

All consumption will be determined in accordance with the metrology procedure issued by the Australian Energy Market Operator.

All Consumption	**35.631 c/kWh**
plus a Service Fee per lamp per day of	**0.668 c**

Tariff 91 **- Other Unmetered Supply –**

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

Unmetered Supply applies where:

1. the load pattern is predictable;
2. for the purposes of settlements, the load pattern (including load and on/off time) can be reasonably calculated by a relevant method set out in the metrology procedure; and
3. it would not be cost effective to meter the connection point taking into account:
   (i) the small magnitude of the load;
   (ii) the connection arrangements; and
   (iii) the geographical and physical location.

Charges are based on consumption determined by the distribution entity.

All Consumption	**20.175 c/kWh**

Charges for installation, maintenance and removal of supply to an unmetered installation may apply in addition to the above charge for electricity supplied. These charges are unregulated.

Part 4

APPLICATION OF TARIFFS FOR CUSTOMERS ON NOTIFIED PRICES – GENERAL

Customers on a Standard Retail Contract may choose to be charged on any of the tariffs that the retail entity agrees are applicable to the customer's installation and provided that appropriate metering is in place.

Tariffs are applied to the electricity consumed at a connection point (as identified by a National Metering Identifier or NMI), as measured by the meter or meters at that connection point. The distribution entity is responsible for the establishment of connection points. Whilst customers have the ability to, at their expense if applicable, request additional meters at their connection point to enable particular tariff arrangements, the distribution entity will only create a new connection point where they have a legislative right or obligation to do so.

If there has been a material change of use at the customer's premises, such that the tariff on which the customer is being charged is no longer applicable, the retail entity may require the customer to transfer to a tariff applicable to the changed use.

If a change to the customer's meter is required to support the applicability of a tariff, other than Tariff 12 or Tariff 13, to a customer, the customer may request the retail entity to arrange for the required meter to be installed at the customer's cost.

For all tariffs, excluding Tariffs 11, 12 and 13, 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.

Residential customers have the option, on application in writing or another form acceptable to the retail entity, of switching from Tariff 11 to Tariff 12, or from Tariff 11 to Tariff 13, provided they have the appropriate metering installed. Prior to 30 June 2014, customers will also be entitled to a further option of switching back to Tariff 11 within 12 months following a switch to either Tariff 12 or Tariff 13. Additional charges may apply should a customer wish to switch tariffs again prior to 30 June 2014.

The date of effect of a tariff change will be:

- the date of the last meter read (provided it is an actual meter read, not an estimated meter read); or
- if field work is required to support the change in tariff (e.g. a new meter is required to be installed), the date the field work is completed.

Billing information for application of monthly or annually based charges

The monthly or annual charges shall be calculated pro rata having regard to the number of days in the billing cycle that supply was connected (days) and one-twelfth of 365.25 days (to allow for leap years). That is:

$$Pa = \frac{P \times 12}{365.25} \times \text{days for monthly charges}$$

$$Pa = \frac{P1}{365.25} \times \text{days for annual charges}$$

Where
Pa is the amount to be billed
P is the monthly charge
P1 is the annual charge
days is the number of days in the billing cycle that supply was connected

Supply Voltage

(a) Low Voltage

Except where otherwise stated, the tariffs in Parts 1 and 2 will apply to supply taken at low voltage (480/240 volts or 415/240 volts, 50 Hertz A.C., as required by the distribution entity).

(b) High Voltage

(i) Customer plant requirements

By agreement between the customer and the distribution entity, supply may be given and metered at a standard high voltage, the level of which shall be prescribed by the distribution entity.

Where high voltage supply is given, a customer shall supply and maintain all equipment including transformers and high voltage automatic circuit breakers but excepting meters and control apparatus beyond the customer's terminals.

(ii) Credits where L.V. tariff is metered at H.V.

Where supply is given in accordance with (i) above and metered at high voltage then, except in cases where high voltage tariffs are determined or provided by agreement to meet special circumstances, the tariffs applied will be those pertaining to supply at low voltage ("the relevant tariff"), EXCEPT THAT, after billing the energy and demand components of the tariff, a credit will be allowed of –

- 5 percent of the calculated tariff charge where supply is given at voltages of 11kV to 33 kV; and
- 8 percent of the calculated tariff charge where supply is given at voltages of 66 kV and above,

(provided that the calculated tariff charge after application of the credit must not be less than the Minimum Payment or other minimum charge calculated by applying the provisions of the relevant tariff.)

Card-operated Meters in Remote Communities

If a customer is a small excluded customer for a premises (as defined in section 23 of the Electricity Act), the distribution entity may at its absolute discretion agree with:

(a) the relevant local government authority on behalf of the customer; and
(b) the customer's retail entity, that the electricity consumed by the customer is to be measured and charged by means of a card-operated meter.

If, immediately prior to 1 July 2007, electricity being consumed by a customer at a premises is being measured and charged by means of a card-operated meter, the electricity consumed at the premises may continue to be measured or charged by means of a card-operated meter.

The methodology for applying the appropriate tariffs to customers subject to card-operated meters is as follows:

(a) If electricity supplied to a residential customer is measured and charged by means of a card-operated meter:
    (i) for Tariff 11 (Residential – Lighting, Power and Continuous Water Heating), all consumption shall be charged at the 'All Consumption' rate (**26.730 cents/kWh**), plus a Service

Fee of **50.219 cents** per day shall apply;

(ii) for Tariff 31 (Night Rate – Super Economy), all consumption shall be charged at the 'All Consumption' rate (**12.370 cents/kWh**); and

(iii) for Tariff 33 (Controlled Supply – Economy), all consumption shall be charged at the 'All Consumption' rate (**18.052 cents/kWh**).

(b) If electricity supplied to a business customer is measured and charged by means of a card operated meter, all consumption shall be charged at the 'All Consumption' rate under Tariff 20 (General Supply) (**23.218 cents/kWh**), plus a Service Fee of **130.161 cents** per day 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 **$15**; and

(c) financial institution fee for a dishonoured payment – no more than the **fee incurred** by the retail entity.

Part 5

CONCESSIONAL APPLICATIONS OF TARIFFS 11, 12 and 13 (RESIDENTIAL)

***Tariff 11* – Residential (Lighting, Power and Continuous Water Heating), *Tariff 12* – Residential (Lighting, Power and Continuous Water Heating) (Time-of-Use) and *Tariff 13* – Residential (Lighting, Power and Continuous Water Heating) (PeakSmart – Time-of-Use) are available to customers satisfying the criteria set out in any one of A, B or C, as follows:**

A. Those separately metered installations where all electricity consumed is used in connection with the provision of a Meals on Wheels service or for the preparation and serving of meals to the needy and for no other purpose.

B. Charitable residential institutions which comply with all the following requirements—

(a) Domestic Residential in Nature. The total installation, or that part supplied and separately metered, must be domestic residential (i.e. it must include the electricity usage of the cooking, eating, sleeping and bathing areas which are associated with the residential usage). Medical facilities, e.g. an infirmary, which are part of the complex may be included as part of the total installation; and

(b) Charitable and Non-Profit. The organisation must be:

(i) a deductible gift recipient under section 30-227(2) of the *Income Tax Assessment Act 1997* to which donations of $2.00 and upwards are tax deductible; and

(ii) a non-profit organisation that:

A. imposes no scheduled charge on the residents for the services or accommodation that is provided (i.e. organisations that provide emergency accommodation facilities for the needy); or

B. if scheduled charges are made for the services or accommodation provided, then all residents must be pensioners or, if not pensioners, persons eligible for subsidised care under the *Aged Care Act 1997* or the *National Health Act 1953*.

C. Organisations providing support and crisis accommodation which comply with the following requirements—

The organisation must:

(a) meet the eligibility criteria of the Specialist Homelessness Services (formerly known as Supported Accommodation Assistance Program) administered by the State Department of Housing and Public Works and is therefore eligible to be considered for funding under this program. (Funding provided to organisations under the Specialist Homelessness Services 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 6

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 may be eligible for one or more of the following forms of relief from electricity charges:

(A) 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, does not have access to, or has severely restricted access to, farm or irrigation water, the fixed components of the customer's electricity charges shall be waived. These fixed charge components include annual fixed charges under Tariff 66, service fees, and minimum payments, but exclude minimum demand charges.

Provided the drought declaration remains operative, the waiver applies to all eligible fixed charges applicable to any account being used for pumping water for farm or irrigation purposes. The waiver shall continue to apply until the drought declaration is revoked.

(B) Deferral of Payment

If a customer of Ergon Energy Queensland Pty Ltd who is a farmer in a drought declared area or whose property is individually drought declared cites financial difficulties as a result of the drought, the customer is entitled to defer payment of the customer's electricity accounts relating to farm consumption.

Ergon Energy Queensland Pty Ltd may charge interest on deferred accounts. However, the rate of any interest charged must not be more than the Bank Bill reference rate for 90 days, as published on the first business day of each quarter.

Subject to the maximum rate of interest that may be charged, the terms of the deferred payment and the repayment of deferred amounts following revocation of the drought declaration will be as agreed between Ergon Energy Queensland Pty Ltd and the customer concerned.

Eligibility for Relief

A customer of Ergon Energy Queensland Pty Ltd seeking relief from electricity charges on the basis that the customer is a farmer who is in a drought declared area or whose property is individually drought declared, must apply in writing to Ergon Energy Queensland Pty Ltd.

If required by Ergon Energy Queensland Pty Ltd, the customer must provide:

(a) evidence that the customer's property is in a drought declared area or is individually drought declared, including the effective date of such drought declaration;

(b) evidence of the water pumping restrictions applicable to the customer's property; and

(c) for tariffs other than Tariffs 62, 65 and 66, a Statutory Declaration stating the specific account(s), and that the connection is being used primarily for pumping water for farm or irrigation purposes; and/or

(d) a Statutory Declaration stating that the customer is experiencing financial difficulties as a result of the drought, the specific account(s) and that the connection is being used primarily for farm purposes.

Standard Retail Contract customers of other retail entities

Standard Retail Contract customers of retail entities other than Ergon Energy Queensland Pty Ltd who are farmers in drought declared areas or who have a property which is individually drought declared under Queensland Government administrative processes can apply directly to the Department of Energy and Water Supply for relief from electricity charges as outlined in (A) above.

APPENDIX F: ASSUMPTIONS USED TO DETERMINE CUSTOMER IMPACTS

Table F.1: Tariff Assumptions

Retail Tariff	*Tariff Type*	*Consumption kWh per annum*	*Demand kW per month*	*Peak*	*Shoulder*	*Off Peak*
Tariff 11	Residential (flat rate)	4,250				
Tariff 12	Residential (time-of-use)	11,000		16%	53%	32%
Tariff 31	Night rate (super economy)	2,000				
Tariff 33	Controlled supply (economy)	2,000				
Tariff 20	Business (flat rate)	5,375				
Tariff 22	Business (time-of-use)	15,250		48%		52%
Tariff 44	Large business (demand small)	203,157	54			
Tariff 45	Large business (demand medium)	785,260	206			
Tariff 46	Large business (demand large)	2,422,237	518			

Sources: Energex and Ergon Energy

APPENDIX G: SUMMARY OF CONCESSIONAL ARRANGEMENTS FOR ENERGY IN QUEENSLAND

Concession Name	*Customers Who Are Eligible*[1]	*Annual Amount*
Electricity Rebate	Customers with a Pensioner Concession Card issued by either Centrelink or Department of Veterans' Affairs, a Department of Veterans' Affairs Gold Card (and recipient of the War Widow Pension or special rate TPI Pension), or a Queensland Government Seniors Card.	$230.46
Medical Cooling and Heating Electricity Concession Scheme	Queensland residents with a qualifying medical condition requiring cooling or heating to prevent the decline of symptoms, who reside at their principal place of residence which has an air-conditioning unit.	$230.46
Reticulated Natural Gas Rebate	As for Electricity Rebate.	$64.23
Home Energy Emergency Assistance Scheme (HEEAS)	Customers must either hold a current eligible concession card or have a base income of no more than the Commonwealth Government's maximum income rate for part-age pensioners or be on their retailer's hardship program or payment plan.	Up to $720 per household per year for a maximum of 2 years
Electricity Life Support Concession Scheme	Customers must be medically assessed in accordance with the eligibility criteria determined by Queensland Health. In addition, oxygen concentrators must be provided rent-free by Queensland Health to persons who hold an eligible concession card and meet the eligibility criteria of the Medical Aids Subsidy Scheme. Kidney dialysis machines must be provided rent-free by Queensland Health to persons based on clinical needs and supplied through Queensland hospitals.	$469.44 per year for each Oxygen Concentrator; $314.40 for each Kidney Dialysis Machine
Drought relief	Certain farmers who use electricity for irrigation pumping	The fixed electricity charge is waived for Ergon Energy customers. The fixed electricity charge is reimbursed for non-market customers of other retail entities.