Queensland Competition Authority

Final Determination

Regulated retail electricity prices 2014-15

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EXECUTIVE SUMMARY

Since the introduction of full retail competition (FRC) on 1 July 2007, electricity customers in Queensland have been able to enter into a market contract with the retailer of their choice. However, some customers (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 (QCA).

The QCA has been delegated the task of determining notified prices for all regulated retail electricity tariffs from 1 July 2013 to 30 June 2016. During that period, the QCA must set notified prices on an annual basis. This Determination relates to the second pricing determination of the Delegation, to apply from 1 July 2014 to 30 June 2015 (the 2014–15 Determination).

In preparing this Determination, the QCA 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 QCA. 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, many customers continue to access notified prices which are not cost-reflective. These arrangements were introduced to reduce 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 QCA has continued to make transitional tariffs available for 2014–15 and beyond for certain customers.

Dealing with carbon uncertainty

There is considerable uncertainty regarding the likely price of carbon in 2014–15. While the Australian Government has initiated the process for repealing the carbon tax, it is uncertain if and when the carbon tax will be repealed in 2014–15.

Given this uncertainty, the QCA has calculated two sets of retail prices. One set, which includes a full pass-through of carbon costs, is to apply up until the carbon tax is repealed. The second, with no carbon costs, could apply after the carbon tax is repealed. It is important to note that the QCA does not have the power to change retail prices mid-year, so in order to do so we would require a new delegation from the Minister for Energy and Water Supply (the Minister) if and when the carbon tax is removed. Alternatively, the Minister could choose to make a new price determination using the carbon-exclusive notified prices calculated by the QCA.

Underlying cost drivers

Cost-reflective notified prices will rise in 2014–15 due to increases in the underlying costs of supply. Most notably, the wholesale cost of energy, which reflects the price of electricity in the national generation market, is expected to increase by 21.5% compared to 2013–14, based on carbon-inclusive estimates. This is driven by expected rises in industrial demand associated with rapid development of the liquefied natural gas (LNG) export industry in Queensland and higher fuel prices (mainly gas).

The surge in wholesale energy costs is offset to some degree by modest decreases in other energy-related costs. These include the renewable energy target (RET) scheme costs and the costs of complying with the Queensland Gas Scheme, which closed on 31 December 2013.

The second major cost driver is the Queensland Government's Solar Bonus Scheme (SBS). The scheme's costs have almost doubled since 2013-14 and will continue to push up prices in future years as distributors recoup costs incurred in paying feed-in tariffs to solar customers. The scheme's impact on network tariffs is expected to peak in 2015–16, at which time about 34% of Energex's network prices will be due to the SBS.

Increases in network costs (excluding costs related to the SBS) are the third major cost driver. Network revenue allowances are approved by the Australian Energy Regulator (AER). Network prices have also increased because of lower than forecast consumption, which means that network charges must rise to recover the allowed revenue.

Retail operating costs (ROC) have increased marginally from 2013–14, in line with inflation. The cost pass-through mechanism has also been applied for the first time to pass-through small-scale renewable energy scheme (SRES) compliance costs that were under-recovered in 2013-14. However, the impact on customer bills is expected to be relatively minor (less than $2 for a typical tariff 11 customer).

The impact of price increases on individual customers will vary depending on their retail tariff(s) and their consumption.

Impacts on residential customers

The main retail tariff for residential customers is tariff 11. There are also two voluntary time-of-use tariffs (tariffs 12 and 13) which customers may choose instead of tariff 11 (if they have the appropriate metering installed). As well as tariffs 11, 12 or 13, residential customers may also use the 'off-peak' or 'controlled load' tariffs (tariffs 31 and 33).

Energex has reduced its network charges to limit the retail bill increase for a typical tariff 11 residential customer to the level indicated in the Draft Determination. Energex has also reduced its network charges for tariffs 12 and 13.

Tariff 11

Historically, tariff 11 has not been cost-reflective, with the service charge (fixed charge) being below cost and the variable charge being above cost. For 2013–14, the QCA 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, the charges for 2014–15 are higher than for 2013–14 and will increase a typical customer's annual bill from $1,407 to $1,599 (13.6%) based on carbon-inclusive prices or to $1,480 (5.1%) based on carbon-exclusive prices. While the carbon-inclusive increase is the same as in the Draft Determination, the carbon-exclusive increase is slightly lower.

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

Table 1 Tariff 11 – Charges and annual bill impacts for the typical (median) customer

		Carbon Inclusive		*Carbon Exclusive*	
Tariff Component	***Transitional 2013–14***	***Transitional 2014–15***	***Change (%)***	***Transitional 2014–15***	***Change (%)***
Fixed charge[1] (cents/day)	50.219	83.414	66.1%	83.414	66.1%
Variable charge[1] (cents/kWh)	26.730	28.015	4.8%	25.378	-5.1%
Annual Bill[2] (GST inclusive) ($)	1,407	1,599	13.6%	1,480	5.1%

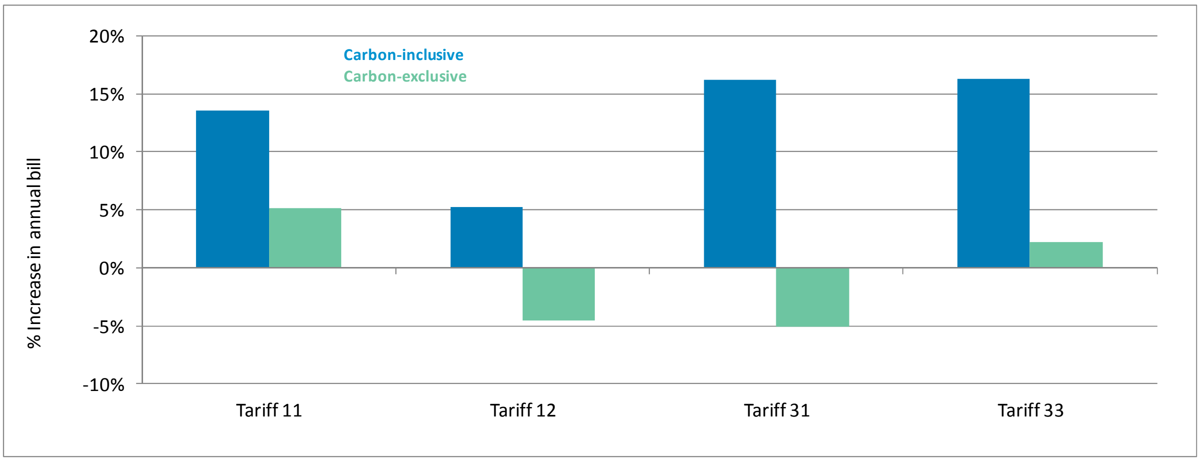
1 GST exclusive.

2 Based on a typical (median) customer on tariff 11 consuming 4,100kWh per year.

Summary of impacts on residential customers

Figure 1 shows the percentage changes that typical residential customers can expect in their annual electricity bills from 2013–14 to 2014–15 for each of the residential tariffs, inclusive and exclusive of the carbon tax. For tariff 11, bill impacts will vary depending on each individual customer's 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.

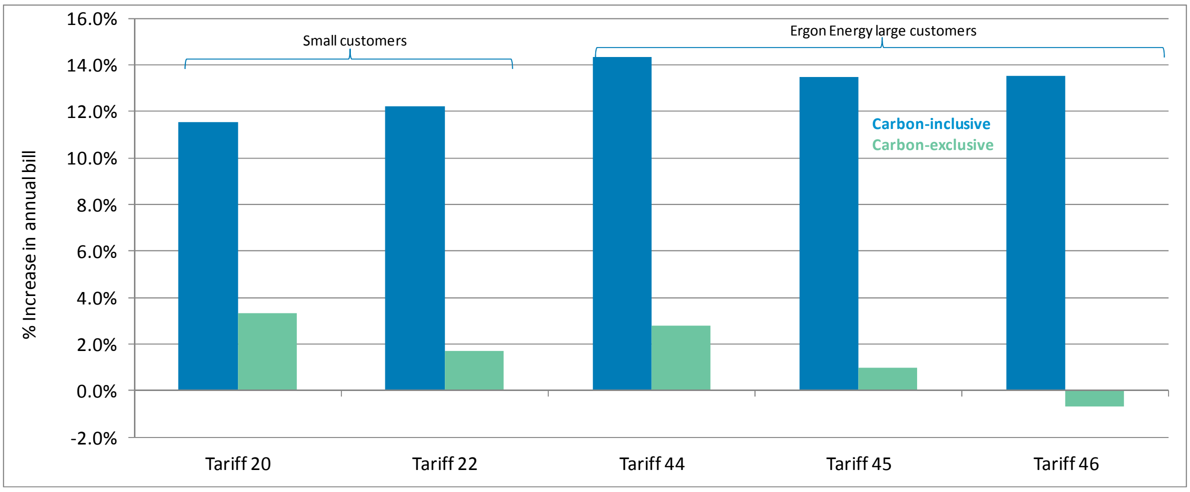
Figure 1 Change in electricity bills in 2014–15 for typical residential customers



Summary of impacts on non-residential customers

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

Figure 2 Changes in electricity bills in 2014–15 for typical business customers



Transitional arrangements

In 2013–14, the QCA extended the transitional arrangements for customers on what were then known as obsolete tariffs. These business customers benefit from the lowest electricity prices in Queensland, with prices below the cost of supply and usually much lower than the cost-reflective prices paid by similar businesses. For example, in 2013-14, an irrigator on transitional tariff 62 pays an off-peak rate of 12.669 c/kWh (GST exclusive), while a business with similar consumption, but on the cost-reflective tariff 22, pays an off-peak rate of 18.668 c/kWh.

The QCA's 2013-14 determination proposed to retain nearly all of these obsolete tariffs until the end of the decade. In 2020, customers would be expected to move to cost-reflective prices.

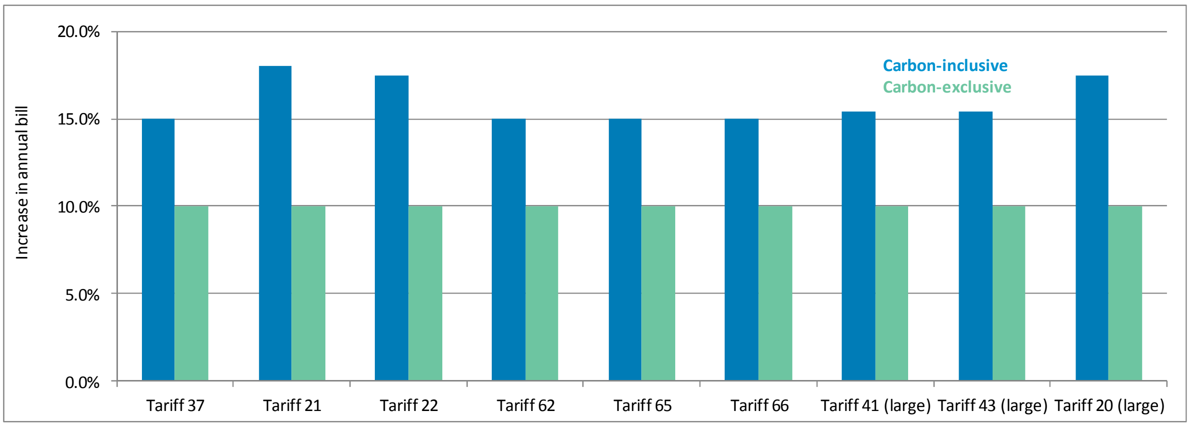
At the same time, the QCA proposed the principle that obsolete tariffs should not become less cost-reflective over the next seven years. The government subsidy to customers on transitional tariffs was around $110 million in 2012-13. The subsidy is likely to be even higher in 2013-14 after the Government capped transitional price increases at 10% while cost-reflective prices increased by around 15% or more. The QCA has retained these transitional arrangements for 2014–15.

For carbon-inclusive prices, we have maintained the approach to transitional prices applied in 2013–14. We have set price increases based on the percentage increases in the relevant cost-reflective tariffs that customers would otherwise pay, plus additional increases to ensure the gaps in dollar terms between prices for transitional and obsolete tariffs and cost-reflective tariffs do not grow over the transition period. On this basis, price (and bill) increases for these tariffs are between 15% and 18%, as shown in Figure 3.

However, if the carbon tax is removed, the percentage increases in cost-reflective tariffs in 2014-15 will be small. As a result, applying the same escalation factors we developed for 2013–14 would do very little to reduce how far customers' bills are below cost in dollar terms. We raised this scenario in the 2013–14 Determination and indicated that higher escalation rates might be needed. Instead, we have decided to set a 10% floor to transitional price increases to prevent the subsidy received by customers on transitional tariffs from increasing.

New customers will be allowed to access the transitional tariffs, 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.

Figure 3 Change in electricity bills in 2014–15 for customers on transitional tariffs



1 INTRODUCTION

Since the introduction of full retail competition (FRC) on 1 July 2007, most electricity customers in Queensland have been able to enter into a competitive market contract with a retailer of their choice. However, most customers are still able to choose to be supplied by their retailer at the regulated or notified prices[1] determined by the Queensland Competition Authority (the QCA).

The QCA has determined notified prices under delegation from the relevant Minister (currently the Minister for Energy and Water Supply) since the start of FRC. However, amendments to the *Electricity Act 1994* (the Electricity Act) and Electricity Regulation 2006 (the Electricity Regulation) in late 2011 significantly changed the method we are required to follow when determining notified prices.

Before 2012–13, we were required to adjust notified prices annually according to our calculation of the change in the Benchmark Retail Cost Index (BRCI). Since then, we have set notified prices based on the N + R cost build-up approach, where we treat the N (network cost) component as a pass-through and determine the R (energy and retail cost) component. This means that retail tariffs are now more cost-reflective than they were under the BRCI approach, although transitional arrangements we have implemented allow certain customer groups a limited period of access to tariffs that are not cost-reflective.

On 5 September 2012, we received a Delegation from the Minister to determine notified prices for a three-year period from 1 July 2013 to 30 June 2016. On 12 February 2013, we received a revised Delegation, which changed the release date of the 2013–14 Draft Determination by one week (see **Appendix A**).

While the Delegation is for three years, we are still required to set notified prices on an annual basis. Our first price determination was made on 31 May 2013 for the period from 1 July 2013 to 30 June 2014. This will be our second price determination and will cover the period from 1 July 2014 to 30 June 2015.

1.1 Matters to consider

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

- the actual costs of making, producing or supplying the goods or services
- the effect of the price determination on competition in the Queensland retail electricity market
- the matters set out in the terms of reference.

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

The Delegation includes a terms of reference which requires that we consider a number of specific matters, including:

[1] Large non-residential customers in south east Queensland (Energex's distribution area) no longer have access to notified prices.

- basing each annual price determination on the N + R cost build-up approach
- in accordance with the Queensland Government's uniform tariff policy (UTP), ensuring 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
- basing the network cost component for residential and small business customers on the network charges to be levied by Energex, and for large business customers, on the network charges to be levied by Ergon Energy
- transitional arrangements for the standard residential tariff (tariff 11), tariffs that were classed as obsolete for 2012–13, and customers on the large customer business tariffs introduced in 2012-13.

1.2 Approach to this review

The Delegation and legislation under which we must make the 2014-15 Determination have not changed since we made our 2013-14 Determination. Given this, and for the purposes of consistency and regulatory certainty, we have broadly maintained the approaches we adopted when making our 2013–14 Determination, including the transitional arrangements we put in place for tariff 11 and the transitional and obsolete tariffs.

The two key factors that we are required to consider when making our price determination are cost-reflectivity and the impact on competition. Consistent with the 2013–14 Determination, we consider that part of our role in setting notified prices is to facilitate the development of competition in the Queensland retail electricity market and provide a transition to price deregulation, particularly in south east Queensland.

Competition in south east Queensland has developed considerably since it was introduced more than six years ago. As a result, around 70% of customers in south east Queensland are supplied under market contracts. The Queensland Government has announced that it will replace retail price regulation with price monitoring in south east Queensland by 1 July 2015, if certain pre-conditions are met[2].

What about regional customers?

In accordance with the Delegation, we have continued to set notified prices that are consistent with the Queensland Government's UTP. As noted above, this means that non-market customers of the same class will have access to the same notified prices wherever they live, even though the costs of supply are considerably higher in regional areas than in the more densely populated south-east of the state.

In order to maintain the UTP, the Queensland Government subsidises the notified prices payable by regional customers supplied by Ergon Energy Queensland (EEQ)[3] via a community service obligation (CSO) payment. This means that most customers in regional Queensland, particularly small customers, do not have access to lower priced competitive market offers

[2] Department of Energy and Water Supply, *The 30-year electricity strategy, Discussion paper*, September 2013, p. 9.

[3] Ergon Energy Queensland is a subsidiary retail business owned by Ergon Energy Corporation Limited (EECL), which is the regulated network business. EECL is referred to in this Final Determination as Ergon Energy.

because other retailers do not have access to the CSO subsidy. As a result, less than 1% of regional customers are supplied by a retailer other than EEQ.

Given that competition is weak, the Queensland Government plans to maintain price regulation for customers in regional Queensland. However, it is also considering options for improving competition, including moving towards a network-based subsidy within three years[4]. On 18 October 2013, the QCA received a Direction from the Minister to provide advice on the efficiency and effectiveness of the UTP and options for maintaining the UTP. We have also been asked to provide advice on approaches to setting notified prices in regional Queensland once price monitoring commences in south east Queensland[5]. We released an issues paper in December 2013[6] and provided our final advice to the Minister at the end of April 2014.

1.3 The review process to date

On 31 July 2013, we released an interim consultation paper advising interested parties of the commencement of the review. We received 25 submissions in response.

We engaged ACIL Allen (formerly ACIL Tasman) to provide expert advice on estimating energy costs. We also held a technical workshop on energy cost issues on 27 September 2013, which was attended by 19 stakeholders.

On 11 December 2013, we released our Draft Determination and ACIL Allen's draft report on the cost of energy (ACIL draft report). This was followed by a series of workshops in Toowoomba, Bundaberg, Rockhampton, Mackay, Proserpine, Townsville, Cairns, Mareeba, Brisbane and Mt Isa in February 2014. We received 32 submissions (including one confidential submission) in response to the Draft Determination.

All papers released, non-confidential submissions received in response, and workshop materials are available from our website, www.qca.org.au. A list of all submissions received to date is provided in **Appendix B**.

We are now releasing this Final Determination, which includes regulated retail tariffs and prices for 2014-15 and explains how these were determined. In making our Final Determination, we have taken into account the requirements of the Electricity Act and the Delegation, matters raised in submissions, ACIL Allen's final report on the cost of energy (ACIL final report) and our own investigations.

[4] Ibid, p. 10.

[5] The Direction Notice is available on the QCA's website: www.qca.org.au.

[6] QCA, *Issues Paper*, *Review of Regional Electricity Price Regulation*, December 2013

2 NETWORK COSTS

Network costs are the costs associated with transporting electricity through the transmission and distribution networks and typically account for around 50% of the final cost of electricity for small customers.

Energex and Ergon Energy have not introduced any new tariffs or changes in the structure of their tariffs for 2014–15, and stakeholders did not raise any new issues with the approach to passing through network costs established for 2013–14. As a result, we have maintained our approach for 2014–15, which includes:

- basing regulated retail tariffs for non-residential customers with consumption greater than 100 megawatt hours (MWh) per year, and for street lighting, on Ergon Energy network tariffs
- basing regulated retail tariffs for all other customers on Energex network tariffs.

2.1 Background

Retail electricity prices comprise three main cost components – network costs, energy costs and retail costs. Network costs are the largest of these and are the costs of transporting electricity from generators to customers, which requires the use of 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 and businesses.

In Queensland, the main transmission network service provider is Powerlink and the two main distribution network service providers are Energex and Ergon Energy. Energex's network services south east Queensland, while Ergon Energy's network extends across the remainder of the state.

As regulated monopoly businesses, Powerlink, Energex and Ergon Energy all earn regulated revenues that are determined by the Australian Energy Regulator (AER). In addition to recovering their own distribution network costs, Energex and Ergon Energy pass Powerlink's costs on to customers in network prices that are also approved by the AER.

The Delegation requires the QCA to adopt a cost-reflective N+R pricing model under which the network costs (N) are to be passed through to customers. The Delegation also requires us to consider:

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

2.2 Network tariffs for residential customers, small business customers and unmetered supplies

Residential tariffs

For the 2013–14 Determination, we used Energex's network tariffs as the basis for setting flat, time-of-use and controlled load regulated tariffs for residential customers.

There was broad support in submissions for continuing to use Energex network tariffs as the basis for notified prices for residential customers in 2014–15. Retailers and distributors agreed that the 2013–14 approach was in accordance with the terms of reference and did not propose any changes to the approach for 2014–15. EnergyAustralia added that maintaining a consistent approach would improve regulatory certainty. Submissions from some customers questioned the structure of, and the costs included in, network prices.

QCA position

We have continued using Energex's network tariffs as the basis for regulated retail tariffs for residential customers. This approach was supported in submissions and is consistent with the Delegation. Any further refinement of, or addition to, these tariffs is a matter for Energex and the AER to determine within the requirements of the National Electricity Rules (NER).

Energex has reduced its network charges to limit the retail bill increase for a typical tariff 11 residential customer to the level indicated in the Draft Determination. Energex has also reduced its network charges for tariffs 12 and 13. Energex's charges for each residential network tariff for 2014–15 are presented in Table 2.

Small business and unmetered supplies

For the 2013–14 Determination, we used Energex's network tariffs as the basis for regulated retail tariffs for business customers consuming less than 100 MWh per year.

Retailers and distributors supported the same approach for 2014–15, on the basis that it is consistent with the requirements of the Delegation.

Farming groups highlighted the effect of previous pricing determinations on their businesses, and called for the creation of a specific 'food and fibre' tariff tailored specifically for the needs of farmers and irrigators. Farming groups also questioned the costs included in network prices.

QCA position

Regarding comments by farming groups about the impact of retail electricity price increases on their businesses, we have updated our assessment of customer impacts and have maintained the transitional arrangements we implemented in 2013–14, which are designed to assist customers in the transition to cost-reflective tariffs (see Chapter 6).

In relation to suggestions by farming groups about network charges, we are required by the Delegation to treat network charges as a pass-through. As a result, we cannot second-guess the tariff structure, or the magnitude of charges, and choose not to pass these costs through in regulated retail prices. Nor can we require the distributors to develop new tariffs for specific customer groups.

Ergon Energy has consulted with farmers and irrigators as part of its network tariff review, which is the appropriate avenue for stakeholders to comment on these issues. However, while Ergon Energy proposes to change the structure of distribution charges for small customers in 2014-15, this will not affect notified prices for 2014–15 because small customer tariffs are based on Energex network tariffs under the terms of the Delegation.

We have continued using 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.

Energex's proposed charges for small business and unmetered supplies are provided in Table 3.

2.3 Network tariffs for large business customers and street lighting

For the 2013–14 Determination, we considered that network charges for Ergon Energy’s east pricing zone, transmission region one, provided the best available basis for setting regulated tariffs for business customers consuming more than 100 MWh per year, and for regional street lighting customers.

There was general support in submissions to maintain this approach for 2014–15. Ergon Energy stated that network tariffs for its east pricing zone, transmission region one, most closely reflect network price signals applicable to large customers in Ergon Energy's supply area. We agree with this view, on the basis that the east pricing zone includes around 90% of large regional customers and transmission zone one has more customers than either of the other two transmission zones.

Ergon Energy's proposed 2014-15 network charges for business customers consuming more than 100 MWh per year, and for regional street lighting customers, are presented in Table 4. The fixed charges for business customers are significantly higher than those for 2013–14. However, this is because Ergon Energy has decided to use the fixed charges to recover revenue that is recovered via minimum monthly demand charges, which will no longer apply. Customers will only be charged for demand use above a minimum monthly threshold. Ergon Energy indicated that these changes will have minimal impacts on customers.

EnergyAustralia supported using Ergon Energy network tariffs as the basis for large customer tariffs, but suggested that new tariffs should be developed for customers outside Ergon Energy’s east pricing zone, transmission region one, to reflect the transmission and distribution network tariffs that apply in those areas. This would improve the cost-reflectivity of notified prices for large customers. In addition, it would remove barriers to competition, as regulated prices for customers outside Ergon Energy's east zone are not cost-reflective, preventing retailers other than EEQ from making offers to customers in these areas. However, the Delegation requires us to consider the Government's UTP, which requires non-market customers of the same class to have access to the same notified prices, regardless of their geographic location. This requires us to set a single network tariff for each customer class.

EEQ raised the issue of street lighting charges for customer connection assets that are owned and maintained by Ergon Energy and suggested that EEQ should be included in any discussion of a price path for passing these charges through to customers. However, as these are not network charges, and can be recovered directly from customers, section 90(3) of the Electricity Act prevents us from including them in notified prices. We understand that the Queensland Government is developing a price path to recover these charges from customers.

QCA position

We have continued using network tariffs for Ergon Energy’s east pricing zone, transmission region one (presented in Table 4), as the basis for regulated retail tariffs for large customers and street lighting.

2.4 Network tariffs for very large customers

In our 2013–14 Determination, we noted that a key difficulty in setting notified prices for very large customers (those consuming more than 4 gigawatt hours (GWh) per year) was that Ergon Energy had confidential, individually-tailored network charges that reflected the unique circumstances of each customer in this diverse group. For this reason, we considered that it was not feasible to base notified prices on the approved (individual) network charges for these customers. Instead, we based the regulated retail tariff (tariff 48) for very large regional customers on the same network tariff (for high voltage demand customers) that tariff 47 was based on.

Ergon Energy supported continuing with this approach for 2014–15 and noted that the Queensland Government is reviewing electricity charges for very large customers. Until the outcome from that review is known, Ergon Energy suggested that its high voltage demand network tariff should be used in determining the regulated retail tariff 48.

Cotton Australia suggested that network charges for very large customers should not be applied in a way that makes electricity uneconomic for businesses west of the Great Dividing Range. However, we note that using network charges in Ergon Energy's east zone already protects customers in the west from the much higher network charges they would pay if they were not on a regulated tariff. Making the network cost element of notified prices for very large customers in the west even lower could only be achieved by making the same reductions for all very large customers, in accordance with the Government's UTP. We do not consider this is possible because it is at odds with the requirement in the Electricity Act that we have regard to the costs of supply in setting notified prices.

QCA position

We have continued using network tariffs for Ergon Energy’s high voltage demand customers in the east pricing zone, transmission region one, as the basis for the regulated retail tariff for very large customers.

Ergon Energy's proposed network charges for this tariff are presented in Table 4.

2.5 Alignment of retail and network prices

Using an N+R approach to setting notified prices requires a formal process to ensure the ongoing alignment of network and retail prices 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 to the AER by the end of April each year. However, there is also no formal limit on the time the AER can take to approve the distributors’ pricing proposals. In previous years, this occurred after the QCA had to publish final notified prices. Any change in the network prices approved by the AER after the QCA has published final notified prices would potentially result in a misalignment of network and retail prices.

In its September 2012 proposal to the Australian Energy Market Commission (AEMC), the Independent Pricing and Regulatory Tribunal (IPART) proposed changes to the NER that 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 QCA. However, it appears that the AEMC does not expect to make a final determination on this request until August 2014.

Previously, we have used proposed network prices the distributors provide to the AER by the end of April each year for the Final Determination. Any material difference between the network tariffs used in the Final Determination and those charged to retailers would be accounted for via the cost pass-through mechanism we implemented in 2013–14, as discussed in Chapter 5.

There was broad support for this approach amongst those stakeholders that commented. EEQ and QEnergy supported the change to the NER proposed by IPART as the preferred solution, while recognising that our approach was appropriate under the current rules.

QCA position

We have continued using network prices provided by Energex and Ergon Energy for this Final Determination. In the event that the final network prices charged to retailers differ from those used in this Final Determination, we will consider using the pass-through mechanism discussed in Chapter 5 to adjust for any material difference, although this will depend on the regulatory arrangements in place for 2015-16.

2.6 Network prices for 2014–15 notified prices

The QCA's Final Determination is to base regulated retail tariffs for 2014–15 on:

- Ergon Energy network tariffs and charges for non-residential customers with consumption greater than 100 MWh per year and for street lighting
- Energex network tariffs and charges for all other customers, including other unmetered loads.

The network charges to be used as the basis for notified prices for 2014–15 are presented in the following tables.

Table 2 Energex network charges for 2014–15 for regulated residential retail tariffs (GST exclusive)

Retail tariff	*Energex network tariff*	*Fixed charge[1] c/day*	*Variable rate (flat) c/kWh*	*Variable rate 1 (off-peak) c/kWh*	*Variable rate 2 (shoulder) c/kWh*	*Variable rate 3 (peak) c/kWh*
Tariff 11 – Residential (flat rate)	8400	59.100	12.640			
Tariff 12 – Residential (time-of-use)	8900	59.100		7.928	11.068	20.042
Tariff 13 – Residential PeakSmart (time-of-use)	7600	59.100		5.956	10.802	19.560
Tariff 31 – Night rate (super economy)	9000		5.544			
Tariff 33 – Controlled supply (economy)	9100		10.061			

1 Charged per metering point.

Table 3 Energex network charges for 2014–15 for other small customer regulated retail tariffs and unmetered supplies other than street lighting (GST exclusive)

Retail tariff	*Energex network tariff*	*Fixed charge[1] c/day*	*Demand charge $/kW/month*	*Variable rate (flat)[2] c/kWh*	*Variable rate (off-peak) c/kWh*	*Variable rate (peak) c/kWh*
Tariff 12 – Residential (time-of-use)[3]	8900	59.100		11.068	7.928	20.042
Tariff 20 – Business (flat rate)	8500	80.500		13.432		
Tariff 22 – Business (two part time-of-use)	8800	80.500			9.240	15.240
Tariff 41 – Low voltage (demand)	8300	677.200	24.139	1.497		
Tariff 91 – Unmetered	9600			10.061		

1 Charged per metering point.

2 Shoulder for tariff 12.

3 Tariff 12 can be accessed by small business customers provided it is in conjunction with a primary business tariff.

Table 4 Ergon Energy network charges for 2014–15 large customer regulated retail tariffs and street lighting (GST exclusive)

Retail tariff	*Ergon Energy network tariff*	*Fixed charge[1] c/day*	*Demand charge $/kW/month*	*Variable rate (flat) c/kWh*
Tariff 44 - Over 100 MWh small (demand)	EDST1	4,436.774	34.589	1.767
Tariff 45 - Over 100 MWh medium (demand)	EDMT1	14,892.378	31.035	1.767
Tariff 46 - Over 100 MWh large (demand)	EDLT1	43,657.361	29.739	1.767
Tariff 47 - High voltage (demand)	EDHT1	35,912.216	21.924	1.701
Tariff 48 - Over 4 GWh High voltage (demand)	EDHT1	35,912.216	21.924	1.701
Tariff 71 - Street Lighting[2]	EVUT1	0.600		20.758

1 Charged per metering point.

2 The fixed charge for street lighting applies to each lamp.

3 ENERGY COSTS

The second main component of retail electricity prices is the cost a retailer will incur, either directly or indirectly, in supplying energy to cover the load of its customers.

For 2014–15, the QCA has decided to maintain a hedging-based approach to estimating wholesale energy costs. In response to stakeholder concerns about carbon uncertainty, we have decided to base wholesale energy cost estimates on carbon-exclusive contracts with a full pass-through of the carbon tax, until the carbon tax is removed.

We have also developed energy cost estimates based on carbon-exclusive contracts with no pass-through of the carbon tax. These are included in the carbon-exclusive notified prices we have calculated (provided in Appendix G) that could apply in the event that the carbon tax is removed.

All other energy costs and energy losses have been calculated on the same basis as in 2013–14.

3.1 Background

In previous decisions, we have included allowances for a range of energy costs that are incurred by retailers, which can be broadly broken into three categories:

- wholesale energy costs
- other energy costs, including green schemes and market fees
- energy losses.

We engaged ACIL Allen to provide advice on each energy cost component in accordance with the terms of reference (ToR) for its engagement (available on our website). We are of the view that retaining the same consultant for this review that we engaged in prior years will provide continuity and certainty to stakeholders.

Requirements of the Electricity Act and Delegation

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

- the actual costs of making, producing or supplying the goods or services
- the effect of the price determination on competition in the Queensland retail electricity market
- any matter required under the Delegation
- any other matter we consider relevant.

The Delegation requires the QCA to consider whether our 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 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 the physical electricity is purchased from the National Electricity Market (NEM), this is a volatile spot market and retailers routinely hedge their price risk. There are a range of measures that a retailer can take to reduce its exposure to volatile prices in the NEM, including purchasing financial derivatives (futures, swaps, options, etc.), entering longer-term power purchase agreements (PPAs) with generators, and investing in generation assets. The wholesale energy costs that a retailer ultimately faces are a function of its exposure to NEM pool prices and the cost of its hedging strategy.

Potential approaches for 2014–15

The two prevalent approaches for estimating wholesale energy costs are the hedging-based model and the long-run marginal cost (LRMC) model. Throughout a number of previous price reviews, we have made clear our preference for using a hedging-based approach, because of its transparency and because we consider it provides the best estimate of the electricity purchase costs faced by a retailer in a given year. We reiterated this preference in our consultation paper.

Retailers and industry organisations highlighted their preference that LRMC be factored into energy cost estimates. However, none provided new information that would compel us to consider changing our approach for 2014–15. Most submissions recognised our preference for the hedging-based approach and focussed their submissions on improvements to that approach.

We remain of the view that the hedging-based approach is best for estimating energy costs. The approach better reflects the value of the electricity that retailers supply, and retaining it for 2014–15 will provide certainty to stakeholders. The AEMC also endorsed the hedging-based approach as the best-practice method for estimating wholesale energy costs for retail prices.[7]

For these reasons, and drawing on our considerations from previous reviews, we have decided to retain the hedging-based approach for 2014–15.

Dealing with carbon uncertainty under a hedging-based approach

Since the carbon tax was introduced in 2012–13, the QCA has used energy cost estimates provided by ACIL Allen that are based on carbon-inclusive energy contracts traded through the Australian Securities Exchange (ASX).[8]

While retailers hedge some of their energy purchases using these contracts, we understand most use alternative methods to hedge the majority of their energy purchases. These alternative methods commonly involve purchasing over-the-counter (OTC) contracts, investing in generation, and entering bilateral contracts with generators. The majority of these alternatives have carbon "pass-through" clauses[9], which mean that retailers pay an underlying carbon-exclusive price for the contract plus an additional amount that reflects the costs associated with the carbon tax, calculated at the time of contract settlement.

In previous years, when market participants expected the carbon tax to remain in place for the entire year, the price of carbon-inclusive ASX contracts aligned very closely with the price of carbon-exclusive OTC contracts plus the carbon pass-through. As a result, we accepted ACIL Allen's advice that carbon-inclusive ASX contract prices were an acceptable proxy for the energy costs incurred by retailers.

[7] AEMC, *Advice on Best Practice Retail Price Regulation Methodology - Final Report,* September 2013.
[8] And previously under the Benchmark Retail Cost Index methodology.
[9] Generally based on the Australian Financial Markets Association (AFMA) Carbon Benchmark Addendum.

However, as evidenced in a number of submissions, carbon-inclusive energy contracts for 2014–15 no longer include the full costs that would be associated with the carbon tax if it was to remain in place for the full year ($22/MWh). Rather, ACIL Allen's analysis suggests a market expectation that the carbon tax will be in place for only 14% of the year (which implies an effective carbon price of $3/MWh). This is in contrast to the carbon costs in the alternative OTC hedging instruments used by retailers that include a carbon pass-through provision, where the cost of carbon will be around $22/MWh while the carbon tax is in place and $0/MWh if it is removed.

As the Delegation requires the QCA to set regulated prices to apply for the entire year, using carbon-inclusive contracts could be reasonable because they represent the market's best guess at expected energy costs for the year, during which only part of the carbon tax will apply. This approach was supported by the Queensland Council of Social Service (QCOSS).

However, under this approach, there would be no change to electricity prices if the carbon tax is removed. This would be at odds with the expectations of customers that electricity prices would likely decrease if the tax is removed.

Furthermore, retailers expressed concern that the use of carbon-inclusive ASX contract prices to set retail prices to apply for the entire year might increase their risks. If the market for carbon-inclusive contracts is correct about when the carbon tax will be repealed, then notified prices based on those contracts would allow retailers to recover their costs, even though they hedge most of their energy purchases by other means. This is because the full carbon costs they will face while the tax remains in place (paid through carbon pass-through clauses) will be offset by the zero carbon costs they will face when the tax is removed.

However, if the market is incorrect, and the carbon tax is removed later than expected, retailers may not recover their carbon costs through the energy cost allowance. Conversely, if the carbon tax is removed earlier than expected, retailers would recover more than their actual carbon costs for the year.

In these circumstances, we consider a better approach is to set notified prices that include the full impact of the carbon tax, to apply for as long as it remains in place. A separate set of prices that does not include any carbon costs could then be implemented after the carbon tax is removed. We think this approach will result in retail price outcomes that better reflect the expectations of customers and the costs faced by retailers.

Origin, EnergyAustralia, Council on the Ageing (COTA), EEQ, the Energy Supply Association of Australia (ESAA), the Energy Retailers' Association of Australia (ERAA) and AGL supported this approach in submissions and it was met with broad support at the technical workshop.

However, AGL noted that some retailers would have already incurred costs to hedge their potential exposure to carbon in 2014–15. AGL suggested that, in the event that a carbon price does not apply in 2014–15, these costs should be recognised in setting wholesale energy costs. No other retailers suggested this approach.

We do not expect this to be a significant issue for larger retailers, which together supply almost 90% of customers in south east Queensland. Larger retailers have noted over a number of years that they hedge the vast majority of their electricity purchases by investing in generation, entering PPAs or purchasing OTC contracts, most of which have a carbon pass-through clause.

To the extent that some smaller retailers may hold carbon-inclusive contracts, they will recover their costs if the market is correct about the timing of the repeal. If the repeal is later than expected, these retailers will have a windfall gain. However, if the repeal is earlier than expected they may not recover their full costs.

Regardless of the approach the QCA takes to setting notified prices, these smaller retailers are likely to under-recover their costs if the carbon tax is repealed earlier than expected because the majority of their customers are on market contracts. In this event, these retailers would be forced to absorb any carbon costs incurred in order to stay competitive (with larger retailers that are not incurring any carbon costs) or because they are required to by the Australian Competition and Consumer Commission (ACCC).[10]

As a result, setting post-carbon tax notified prices based on carbon-inclusive ASX contract prices may not allow smaller retailers to recoup any carbon costs already incurred. It will simply provide the larger retailers, who have the vast majority of non-market customers and zero or low carbon costs after the tax is removed, with a windfall gain.

Carbon-inclusive ASX contract prices have moved closer to the estimated carbon-exclusive OTC contract prices since the Draft Determination, revealing the market's increasing expectations that the carbon tax will be removed sometime during 2014–15. However, until the carbon tax is actually removed, the QCA considers it prudent to set prices assuming that the tax will be in place for the full year and adjust prices only when it is removed. To do otherwise might place retailers at considerable risk if the carbon tax remains in place longer than anticipated.

Taking this approach means setting an initial set of prices that we acknowledge are too high to apply for the entire year, given market expectations that the carbon tax will be repealed mid-year. However, we consider this approach is allowed under section 90(5)(b) of the Electricity Act, which allows the QCA to have regard to any other matter we consider relevant to setting prices.

For these reasons we have also calculated notified prices that could apply after the carbon tax is removed that do not include any allowance for carbon costs.

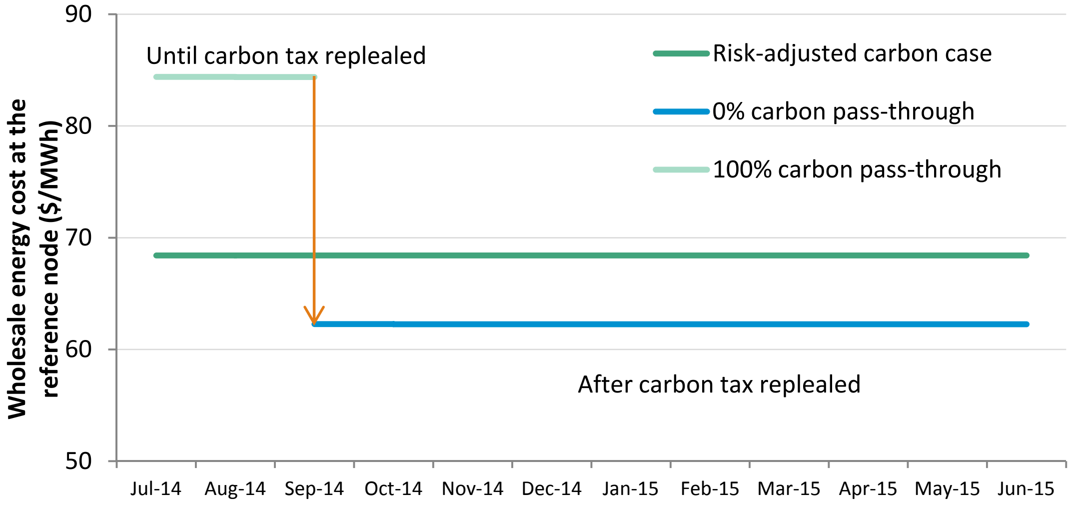
In order to implement this approach, we asked ACIL Allen to develop two sets of energy cost estimates for 2014–15 (in addition to the full-year estimates we originally requested) based on:

- contract prices including a full pass-through of the carbon tax. This allowance would be applicable until the carbon tax is removed
- contract prices with no pass-through of the carbon tax. This allowance would be applicable if the carbon tax is removed.

Figure 4 illustrates the different outcomes of each approach based on ASX Energy data available as at 31 March 2014. Application of our previous methodology, based on carbon-inclusive contracts, results in a wholesale energy cost estimate for the Energex net system load profile (NSLP) of $68/MWh at the regional reference node. The new scenarios with a 0% and 100% pass-through of carbon result in costs of $62/MWh and $84/MWh.

[10] Australian Government, *Clean Energy Legislation (Carbon Tax Repeal) Bill 2013,* November 2013.

Figure 4 Wholesale energy costs for Energex NSLP— different carbon scenarios for 2014–15



Note: Repeal of the carbon tax is assumed to occur during August and is for illustrative purposes only. This assumption is based on market expectations that the carbon tax will remain in place for 14% of the 2014-15 year.

It is important to note that the QCA does not have the power to change retail prices mid-year. In order to do so, we would require a new delegation from the Minister if and when the carbon tax is removed. Alternatively, the Minister could choose to make a new price determination using the carbon-exclusive notified prices calculated by the QCA.

A further complication is that the carbon tax might be 'repealed' from 1 July 2014, even if parliament passes the repeal bills at some later date.[11] If this eventuates, generators might be required to pay back carbon costs to retailers retrospectively, who could then be expected to pay these costs back to customers. It is unclear how such a process would be implemented. However, we think it is unlikely that notified prices will be affected because reimbursement will be required for all customers (not just those on notified prices), and will involve compensating customers who actually paid carbon costs between 1 July 2014 and when the tax is removed (not providing some carbon-related discount in notified prices that would potentially benefit customers who did not incur any carbon costs).

Enhancing time-of-use signals

The Delegation requires the QCA 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.

In previous reviews, the QCA 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 the Australian Energy Market Operator (AEMO), which is based on the relevant distributor's NSLP.

To resolve this issue, the Queensland Government has to propose amendments to AEMO's Metrology Procedures to align Queensland's procedures with those of other states.

[11] Australian Government, *Clean Energy Legislation (Carbon Tax Repeal) Bill 2013*, November 2013.

Other modelling considerations

Submissions also queried a number of technical aspects of ACIL Allen's modelling methodology, including:

- the number of high-price periods in ACIL Allen's spot price forecasts for 2013–14
- the relationship between a one-in-ten year load outcome and a one-in-42 year load outcome
- the impact of consecutive hot days on electricity consumption and spot prices
- the correlation between demand outcomes and temperatures above 35 degrees Celsius
- the treatment of timing differences between the assumed hedging strategy and the actual purchases of contracts by retailers
- the averaging method for deriving the inferred risk-adjusted carbon price
- the assumptions about cap contract volumes
- the frequency of positive payouts from cap contracts.

ACIL Allen has considered and responded to these issues in its draft and final reports. Following consideration of the various criticisms and suggestions provided in the submissions, ACIL Allen has made some minor refinements to its method for estimating wholesale energy costs, which are discussed in its final report. With the exception of these changes, no other compelling new material has been presented in submissions to persuade ACIL Allen to further modify its modelling approach. The QCA accepts ACIL Allen's advice on these matters.

Detailed explanations of ACIL Allen's modelling approach, data sources and assumptions are contained in its draft and final reports to the QCA.

2014–15 Wholesale energy costs – carbon inclusive and exclusive

Table 5 outlines ACIL Allen’s wholesale energy cost estimates for 2014–15 based on hedged price outcomes, with and without a carbon pass-through. Wholesale energy costs at the regional reference node (including carbon) are expected to increase by 21.5% compared to 2013–14 reflecting:

- the tightening of the supply-demand balance for electricity due to increased load from LNG plants in Gladstone
- significantly higher fuel prices (mainly gas) compared with 2013–14.

Table 5 Estimated carbon-inclusive and -exclusive wholesale energy costs at the regional reference node for 2014–15

Settlement class	***Retail tariff***	***Carbon-exclusive***		***Carbon-inclusive***	
		$/MWh	***% change from 2013–14***	***$/MWh***	***% change from 2013–14***
Energex NSLP and unmetered supply	11, 12, 13, 20, 22, 41, 91	62.26	30.4%	84.38	21.5%
Energex Controlled Load 9000	31	36.60	44.9%	58.67	24.7%
Energex Controlled Load 9100	33	50.71	39.0%	72.03	24.4%
Ergon Energy NSLP and streetlights	44, 45, 46, 47, 48, 71	55.75	31.7%	77.75	21.3%

Source: ACIL Allen, Estimated Energy Costs for 2014–15, May 2014.

3.3 Other energy costs

In addition to wholesale energy costs, there are a range of other energy costs including those relating to:

- the large-scale renewable energy target (LRET) scheme
- the small-scale renewable energy scheme (SRES)
- NEM participation fees and ancillary services charges
- prudential requirements.

The inclusion of a cost pass-through mechanism to account for under-recovered SRES costs (where material) is discussed in Chapter 5.

LRET costs

The LRET scheme 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) that is determined on the basis of achieving the annual target, which increases annually toward the ultimate goal of 41,000 GWh by 2020.[12]

For the 2013–14 Determination, ACIL Allen estimated LRET costs using the 2013 renewable power percentage (RPP) for the first half of the pricing period and the 2014 LRET target for the second half of the pricing period, as the 2014 RPP was not published at the time of the Final Determination. To estimate the cost of meeting these targets, ACIL Allen used LGC prices published by the Australian Financial Markets Association (AFMA).

[12] *Renewable Energy (Electricity) Act 2000.*

In submissions, retailers proposed (as they have in previous reviews) that an approach based on the LRMC of renewable generation was more appropriate than using LGC prices from AFMA. EnergyAustralia and Origin Energy pointed to the low level of liquidity in the secondary LGC market as support for adopting an LRMC approach.

QCOSS disagreed with this view in its submission on the basis that market-based LRET costs more closely reflect the costs to retailers.

Following an examination of market prices over recent years, ACIL Allen concluded that the market price has reacted as expected to uncertainty over carbon pricing and the recently announced review of the LRET and provides an accurate basis to estimate LRET compliance costs. ACIL Allen has provided a detailed explanation of its calculation of LRET costs in its draft report, along with information on LGC prices and assumptions underpinning the RPPs.

EEQ suggested that falling liquidity could be accounted for by using a four-year book-build period. EEQ also suggested that the Tradition Financial Services (TFS) market data would be more transparent than the AFMA data used in previous years.

ACIL Allen has retained its previous approach for estimating LRET costs, on the basis that there were no new or persuasive arguments in submissions.

The QCA has considered, and decided against, adopting an LRMC approach for estimating LRET costs in previous pricing determinations. We have a preference for using market-based approaches to estimating costs where possible rather than proxies such as LRMC on the basis that market-based approaches are more transparent and more likely to reflect the costs incurred by a retailer in any given year. On this basis, we accept ACIL Allen's advice on this matter, and its LRET cost estimates outlined in Table 6.

Small-scale renewable energy scheme (SRES) costs

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.

For the 2013–14 Determination, ACIL Allen estimated SRES costs using the binding 2013 small-scale technology percentage (STP) target for the first half of the pricing period and the non-binding 2014 target for the second half of the pricing period, as the binding target was not published at the time of the Final Determination. To estimate the cost of meeting these targets, ACIL Allen used the clearing house price of $40 per STC, on the basis that it expected any difference between market prices and the clearing house price to diminish over time. QCOSS disagreed with this approach and considered that market prices should be used to estimate the STC price.

With the exception of QCOSS, stakeholders were broadly in favour of retaining the existing approach for 2014–15. QEnergy argued for an additional allowance for the forecast risk between the non-binding STP (which, due to timing issues, must be used in the Final Determination) and the binding STP published by the Clean Energy Regulator (CER).

The QCA acknowledges QEnergy's concern regarding the use of non-binding STPs and the potential for it to create a shortfall between the SRES allowance in notified prices and the liability retailers actually face. We have implemented a pass-through mechanism to account for this, which means that an additional allowance is unnecessary. The pass-through mechanism and the treatment of the 2013–14 SRES shortfall are discussed further in Chapter 5. ACIL Allen has retained its previous approach for estimating SRES costs, on the basis that submissions were generally supportive of the approach. We are satisfied with ACIL Allen's approach and accept its SRES cost estimates, as outlined in Table 6.

NEM participation fees and ancillary services charges

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

For the 2013–14 Determination, ACIL Allen used AEMO budget and fee projections as the source of forecast NEM participation fees. Ancillary services charges were based on the average historical costs observed over the preceding 52 weeks.

Submissions generally supported retaining this approach for 2014–15. Given this support, ACIL Allen followed the same approach for 2014–15 and its cost estimates are outlined in Table 6.

Prudential capital

Prudential capital costs relate to the financial guarantees a retailer must provide to AEMO and initial margins lodged with the ASX for futures contracts. In 2013–14, we provided an allowance to reflect the higher capital requirements faced by retailers that use futures to hedge rather than entering into PPAs or investing in generation.

Submissions raised no objections to the methodology used by ACIL Allen to determine costs for 2013–14, with the exception of QEnergy and QCOSS. QEnergy argued that wholesale market volatility had increased since the 2013–14 Determination, and to avoid having last-minute calls for additional prudential capital impact on its cash flow, it now holds excess prudentials with AEMO as a matter of course. QEnergy suggested that the allowance calculated by ACIL Allen was insufficient to cover these higher prudential costs. QCOSS considered that the case for including a prudential capital allowance as a separate cost item is not proven.

We maintain our view that it is appropriate to account for prudential costs in the context of estimating the cost of energy because we still rely on futures contracts as the basis of our wholesale energy costs estimates. We note comments made by QEnergy regarding increased market volatility and the effect on AEMO prudential requirements. ACIL Allen has estimated prudential allowances based on current market volatility levels, as outlined in Table 6.

Summary of other energy costs for 2014–15

Table 6 shows the other energy cost allowances for 2014–15 which will be applied uniformly across all tariffs.

Table 6 Other energy costs —all tariffs— excluding losses

Cost Component	*2013–14 Final Determination*	*2014–15 Final Determination*	*Change*
	$/MWh	*$/MWh*	*%*
Queensland Gas Scheme[1]	0.25	0.00	-100.0%
LRET	4.15	4.01	-3.4%
SRES	5.74	4.12	-28.2%
NEM Fees	0.37	0.47	27.0%
Ancillary Services	0.30	0.48	61.0%
Prudential Capital	0.58	0.71	22.8%
Total	**11.38**	**9.79**	**-14.0%**

Source: ACIL Allen, Estimated Energy Costs for 2014–15, May 2014.

1 The Queensland Gas Scheme ended on 31 December 2013.

Note: Totals may not add due to rounding.

3.4 Energy losses

A retailer must purchase sufficient energy to supply its customers' load and allow for the transmission and distribution losses that will be incurred. In the 2013–14 Determination, we applied transmission and distribution losses published by AEMO in a manner that aligns with AEMO's settlement process. Submissions supported this approach.

ACIL Allen has retained its approach to applying losses for 2014–15 and its loss factors are presented in Table 7.

3.5 Total energy cost allowances for 2014–15

Table 7 shows the total carbon-inclusive energy cost allowances for each retail tariff for 2014–15.

Table 7 Total carbon-inclusive energy allowances for 2014–15

Settlement class	*Retail Tariff*	*Wholesale energy*	*Other energy*	*Energy losses*	*Total energy allowance*		*Change from 2013–14*
		$/MWh	*$/MWh*	*%*	*$/MWh*	*c/kWh*	*%*
Energex NSLP and unmetered supply	11, 12, 13, 20, 22, 41, 91	84.38	9.79	7.1%	100.82	**10.082**	16.27%
Energex Controlled Load 9000	31	58.67	9.79	7.1%	73.30	**7.330**	16.89%
Energex Controlled Load 9100	33	72.03	9.79	7.1%	87.60	**8.760**	17.85%
Ergon Energy NSLP – small, medium and large demand and streetlights	44, 45, 46, 71	77.75	9.79	15.2%	100.89	**10.089**	17.79%
Ergon Energy NSLP-high voltage demand and customers over 4 GWh high voltage demand	47, 48	77.75	9.79	8.9%	95.35	**9.535**	16.14%

Source: ACIL Allen, Estimated Energy Costs for 2014–15, May 2014.

4 RETAIL COSTS

In setting the R component of notified prices, the QCA makes an allowance for retail costs, which comprise retail operating costs (ROC) and the retail margin. ROC are the costs associated with services provided by a retailer to its customers. The retail margin is the reward to investors for a retailer's exposure to systematic risks associated with providing customer retail services.

Consistent with the 2013–14 Determination, we have adopted a benchmarking approach to set retail costs for this Final Determination. As we are not aware of more recent relevant benchmarks to use, or new information to update our analysis, we have:

- maintained the 2013–14 ROC allowances in real terms and continued to apply ROC to the fixed component of retail tariffs
- maintained the retail margin at 5.7% of total costs (including the margin) and continued to apply it equally (on a percentage basis) to each component (fixed, variable and demand) of each retail tariff.

4.1 Retail operating costs

ROC are the costs of services provided by a retailer to its customers and typically comprise 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

For our 2012–13 and 2013–14 Determinations, we adopted a benchmarking approach to estimate the ROC allowances because we considered that a bottom-up approach may not necessarily have produced results that were any more robust or defensible.

Retailers generally supported a continuation of the benchmarking approach for the 2014–15 Determination, as did QCOSS. Queensland Dairyfarmers' Organisation (QDO) disagreed with the approach because it is based on cost data from retailers that may not reflect opportunities for cost efficiencies. The Queensland Consumers' Association favoured a bottom-up approach because it considered that this would provide a better estimate of retailers' actual costs.

We consider that there are sensible reasons to continue with a benchmarking approach. Firstly, we have previously set out in detail our reasons for pursuing a benchmarking approach and consider that these reasons remain valid[13]. Secondly, it will provide certainty to stakeholders, particularly as this is the second year of a three-year delegation period. Thirdly, the Queensland Government's[14] recent proposal to remove retail price regulation in south east Queensland by 1 July 2015 suggests that it is questionable whether changing to a potentially data-intensive bottom-up approach for one year is warranted. Depending on the regulatory framework that

[13] QCA, *Regulated Retail Electricity Prices 2013-14, Final Determination*, May 2013, pp. 43-44; QCA, *Regulated Retail Electricity Prices 2012-13, Final Determination*, May 2012, pp. 56-57.

[14] Queensland Government, *Response to the Interdepartmental Committee on Electricity Sector Reform*, June 2013; p. 9; and Minister for Energy and Water Supply, The Honourable Mark McArdle, *Media Release: End of electricity price regulation to improve competition*, 17 June 2013.

will be established to regulate retail prices in regional Queensland, it is likely that we will need to reconsider the approach to setting ROC in future.

QCA position

We have decided to continue to use a benchmarking approach to determine the ROC allowance for 2014–15 notified prices.

4.1.2 Implementing the benchmarking approach

In previous determinations, we set three separate ROC allowances for small, large and very large customers, and have done the same for this Final Determination.

Establishing a benchmark ROC allowance for residential and small customers

In our 2013–14 Determination, we increased the ROC allowance to reflect the allowance adopted by IPART in its 2013 to 2016 draft decision[15]. IPART estimated ROC using a bottom-up approach based on cost information provided by retailers and then benchmarked this estimate against regulatory decisions in other jurisdictions and retailers' publicly reported costs. We considered that it was appropriate to adopt IPART's estimate because it reflected the most up-to-date and relevant information on the efficient level of ROC. We also considered that it was appropriate to add back IPART's estimate of the costs associated with late payments ($3.80 per customer) because, unlike in New South Wales (NSW), retailers in Queensland cannot charge a separate late payment fee. This resulted in a total benchmark ROC allowance of $113.80 ($2012–13).

In our 2013–14 Determination, we expressed the view that this allowance should be maintained in real terms for the remainder of the delegation period, subject to considering any updated analysis in IPART's final decision. However, IPART did not change the ROC allowance between its draft and final decisions. We have also reviewed the recent price determination of the Office of the Tasmanian Economic Regulator (OTTER)[16] and the recent draft price determination of the ACT's Independent Competition and Regulatory Commission (ICRC)[17]. However, we do not consider that either decision provides any new information because both regulators effectively applied a benchmarking approach to set ROC.

AGL, EnergyAustralia, ERAA and Origin Energy considered that the 2013–14 ROC allowance should be maintained in real terms.

QCOSS suggested that the ROC allowance should be based on the costs of large retailers that have achieved economies of scale. In contrast, Alinta Energy and Lumo Energy suggested that the allowance should be higher, as it should be set for a smaller new entrant retailer, rather than a larger incumbent. When setting ROC, we aim to reflect the efficient costs of supplying customers, not the potentially higher costs of small retailers. We also make an allowance for headroom, which is intended to sustain an appropriate level of competition.

EEQ suggested that we should consider adjusting the benchmark to account for Queensland-specific issues that may impact ROC. In particular, EEQ suggested that retailers' costs have increased because:

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

[16] OTTER, *Report on the investigation of maximum prices for interim price-regulated electricity retail services for small customers on mainland Tasmania, Report*, July 2013; and OTTER, *Statement of Reasons on Changes to the Interim Price-regulated Retail Service Price Determinations*, December 2013.

[17] ICRC, *Standing offer prices for the supply of electricity to small customers, Draft Report,* February 2014.

- rising electricity prices have led to higher debt levels
- retail tariff reform has required retailers to invest in updating their systems and processes.

We consider that significant increases in electricity prices are not unique to Queensland. IPART noted that one of the main reasons it increased the ROC allowance was increased debt levels. EEQ was the only retailer that claimed that retail tariff reform had increased ROC. We consider that reviewing and modifying tariffs is a normal business activity for retailers operating in a competitive market and does not warrant an adjustment to the benchmark.

While Cotton Australia suggested that the costs for late payment should not be included in notified prices, we maintain our view that those costs should be accounted for because, unlike in NSW, retailers in Queensland cannot charge a separate late payment fee, as noted above.

Customer acquisition and retention costs

Cotton Australia, QCOSS, the Queensland Consumers' Association and the Queensland Farmers' Federation suggested that there should be no allowance for CARC, mainly because many customers in Ergon Energy's area cannot access a competitive offer. Retailers generally supported the inclusion of a CARC allowance.

We maintain our view from previous consideration 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. Failing to recognise a legitimately incurred cost may reduce the incentive for retailers to actively participate in the market.

For our 2013–14 Determination, we assessed the reasonableness of our 2012–13 allowance against a range of estimates that IPART included in its 2013 to 2016 draft decision. The QCA's 2012–13 allowance of $43 ($2012–13) was lower than IPART's estimate based on information from retailers ($48), and around the mid-point of the range of estimates of publicly listed companies ($34 to $51). This suggested that our 2012–13 allowance was set at a reasonable level and we decided to maintain it in real terms for 2013–14.

QCOSS and the Queensland Consumers' Association considered that, if a CARC allowance continues to be included, it should be lowered because some retailers have stopped door-to-door marketing. Origin Energy suggested that there was no evidence to support the claim that CARC should be reduced, while Alinta Energy suggested that CARC should not be reduced, even if retailers' marketing strategies have changed. AGL suggested that CARC should be maintained in real terms.

Our CARC allowance is not based on any particular form of marketing and we consider that it is set at a reasonable level.

QCA position

In the absence of compelling reasons to change our approach, we have decided to maintain the 2013–14 ROC allowance (including CARC) in real terms and will again include an additional allowance for regulatory fees (see below).

Establishing benchmark ROC allowances for large business customers

We have previously found limited evidence with which to determine an appropriate ROC allowance for large customers, because regulators in most other jurisdictions only determine retail electricity prices for small customers. However, for our 2012–13 Determination, we were able to draw on analysis conducted by Frontier Economics (Frontier) for the Western Australian

Office of Energy in 2009[18] and Economic Regulation Authority (ERA)[19] in 2012. Frontier's analysis suggested that the cost of servicing larger customers was significantly higher than the cost of servicing smaller 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 with which to determine the ROC for large customers, we accepted that retailers may incur higher costs to target larger customers, as they are less numerous and hence low-cost blanket marketing would not be appropriate. We also noted that larger customers are likely to require more time and effort on the part of retailers, 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 manage their accounts.

We decided to set higher ROC allowances for large and very large customers based on Frontier's analysis. No additional allowance was provided for CARC because it was implicitly included in Frontier's estimates. We maintained these allowances in real terms for our 2013–14 Determination.

The Queensland Dairyfarmers' Organisation (QDO) questioned our methodology for calculating the ROC allowances in tariffs for large and very large customers, and our claim that larger customers are more expensive to serve than smaller customers. It suggested that retailers may enjoy some efficiencies in serving large customers, but did not say what those efficiencies might be.

QCA position

As we are not aware of any new evidence with which to update our estimates for 2014–15, we have maintained the 2013–14 allowances for large and very large customers in real terms, and will again include an additional allowance for regulatory fees (see below).

Regulatory fees

As we have in the past, we have included an allowance for the regulatory fees that we charge retailers. Alinta Energy and Origin Energy supported the inclusion of such an allowance.

QCOSS disagreed with the inclusion of regulatory fees, unless it can be shown that regulatory fees differ materially between Queensland and other jurisdictions. QCOSS suggested that if regulatory fees do differ, it is the difference between fees in Queensland and other jurisdictions that should be reflected in ROC, not the full amount of regulatory fees in Queensland.

Our ROC estimate is based on IPART's ROC estimate and we understand that IPART does not impose a levy on retailers to cover the costs of regulating the electricity industry in NSW. Therefore, we consider it appropriate to include a separate allowance for regulatory fees.

The aggregate of fees to be paid by retailers is calculated based on our estimate of the annualised cost of performing our functions over the five-year period from 1 July 2010 to 30 June 2015. The total cost to be paid by retailers in 2014–15 is estimated to be $2,792,000.

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

[19] Frontier Economics, *Retail Operating Costs – A Report Prepared for the Economic Regulation Authority of Western Australia*, February 2012.

This total cost is to be recovered from retailers according to their market share. Based on the most recently available data on customer numbers of 2,094,705 (as at 31 March 2014), this translates into a cost per customer of $1.33 for 2014–15.

QCA position

We have included an allowance of $1.33 per customer for regulatory fees.

Conclusion on retail operating costs

In summary, we have:

- set three different ROC allowances to reflect the costs of supplying small, large and very large customers
- escalated the 2013–14 ROC allowances by the forecast change in the consumer price index (CPI), except for regulatory fees which are separately estimated
- included a separate allowance for QCA regulatory fees.

These allowances are presented in Table 8.

Table 8 Final Determination — 2014–15 ROC ($ per customer)

	2013-14 Final Determination	***2014-15 Final Determination***
Small customers consuming up to 100 MWh/yr:		
Benchmark ROC	116.65	119.85
+ CARC	44.25	45.46
+ Regulatory fees	1.27	1.33
Total ROC	162.16	166.65
Large customers (consuming between 100 MWh and 4 GWh/yr):		
Benchmark ROC (incl CARC)	717.50	737.23
+ Regulatory fees	1.27	1.33
Total ROC	718.77	738.56
Large customers (consuming more than 4 GWh/yr):		
Benchmark ROC (incl CARC)	2,050.00	2,106.38
+ Regulatory fees	1.27	1.33
Total ROC	2,051.27	2,107.71

Where relevant, CPI of 2.75% is used, which is consistent with the mid-range of the RBA forecast of 2.25-3.25% for the 12 months to 30 June 2015. Source: Reserve Bank of Australia, Statement on Monetary Policy, February 2014.

4.1.3 Applying ROC to retail tariffs

In our 2013-14 Determination, we decided to allocate the ROC allowances to the fixed component of retail tariffs because we could not find any evidence to suggest that these costs vary with electricity consumption. No ROC allowances were applied to the controlled load retail tariffs and unmetered retail tariffs because we assumed that customers accessing those tariffs will also access another general supply tariff and pay their fixed charges in that context.

While most submissions did not comment on this issue, AGL and EnergyAustralia supported a continuation of the approach adopted in 2013–14.

EEQ suggested that most accounts that include an unmetered supply tariff (tariff 71 - street lights and tariff 91 - other unmetered supply), do not also include another general supply tariff, meaning that ROC are not recovered. It is unclear why EEQ has not raised this issue before. Further information obtained from EEQ showed that these accounts are often held by customers (such as state or local government agencies) that are charged other tariffs on different accounts. These customers will pay ROC through other tariffs they are on. This outcome is consistent with our consideration of the issue in our 2012-13 Determination[20], where we set out our view that a customer should pay ROC once, regardless of how many tariffs they access.

In the absence of compelling reasons to change our approach, we have continued with the approach adopted in the 2013-14 Determination, which is to apply the ROC allowance to the fixed component of each retail tariff, except:

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

Conclusion on retail operating costs

We have applied the relevant ROC allowance (for small, large and very large customers) to the fixed component of each retail tariff, as follows:

- the small customer ROC of $166.65 per customer will apply to all residential and small business customer retail tariffs (tariffs 11, 12, 13, 20, 22 and 41)
- the large customer ROC of $738.56 per customer will apply to retail tariffs where consumption is generally between 100 MWh and 4 GWh per year (tariffs 44, 45, 46 and 47)
- the very large customer ROC of $2,107.71 per customer will apply to the retail tariff where consumption is generally greater than 4 GWh per year (tariff 48)
- no ROC will apply to controlled load retail tariffs (tariffs 31 and 33) or unmetered retail tariffs (tariffs 71 and 91).

Table 9 presents these allowances as daily charges.

Table 9 Final Determination — ROC allowances for 2014–15 — Fixed Charge[1]

Retail Tariff	***2013-14 Final Determination (c/day)***	***2014-15 Final Determination (c/day)***
11, 12, 13, 20, 22, 41	44.397	45.626
44, 45, 46, 47	196.788	202.208
48	561.607	577.059

1 Charged per metering point.

[20] QCA, *Final Determination: Regulated Retail Electricity Prices 2012-13*, May 2012.

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 customer retail services. A retail margin that 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 our 2012–13 and 2013–14 Determinations, we set the retail margin on an earnings-before-interest, tax, depreciation and amortisation (EBITDA) basis. This meant that an allowance for depreciation and amortisation was implicitly included. The retail margin was also calculated as a percentage of total costs.

In our 2012–13 and 2013–14 Determinations, we adopted a benchmarking approach to set the retail margin. We adopted this approach because we were 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.

AGL, EEQ, EnergyAustralia, Origin Energy and QCOSS broadly supported continuing the benchmarking approach for 2014–15. Consistent with our reasons for continuing to adopt a benchmarking approach to set ROC, we consider that it is appropriate to continue with a benchmarking approach to set the retail margin. Origin Energy supported our approach of applying the retail margin to all costs, as managing the network pass through creates significant cash flow risks for retailers. In contrast, Queensland Consumers' Association was concerned that calculating the retail margin as a percentage of total costs means that the size of the margin increases in dollar terms when costs rise.

While we estimate 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, as the Essential Services Commission of South Australia (ESCOSA)[21] did in its 2010 determination. Given that the alternative would simply result in a higher margin to be applied to fewer costs (than if it were applied to all cost components), we consider that the choice between these two approaches would make little difference.

QCA position

We have continued to apply the benchmarking approach to estimate the retail margin and to calculate the retail margin as a percentage of total costs.

4.2.2 Implementing the benchmarking approach

In our 2013–14 Determination, we set the retail margin at 5.7% to reflect the margin that IPART adopted in its 2013 to 2016 draft decision. IPART engaged a consultant to provide advice on a feasible range for the retail margin using three approaches — expected returns, benchmarking and bottom-up — and applied equal weighting to the margins estimated under each approach. We decided that it was appropriate to adopt the same retail margin as IPART, because it was the most recently estimated benchmark available, it was based on extensive analysis, and we considered that retailers face similar levels of risk in Queensland and NSW.

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

AGL, EnergyAustralia, ERAA and Origin Energy considered that a retail margin of 5.7% should continue to apply in 2014–15. QCOSS suggested that the margin should be lower because:

- retailers' risks are lower than when prices were set under the BRCI approach
- our revised approach to estimating wholesale energy costs, which uses the 95th percentile of hedged outcomes, reduces retailers' risk.

We have adopted a retail margin that reflects the most up-to-date estimate of the appropriate margin for retailers in the circumstances they now face. It has not been determined by reference to the margin established under the BRCI. We also note that the retail margin accounts for retailers' exposure to systematic risks, while other aspects of the determination (including the wholesale energy cost allowance) account for other risks.

In light of our continued role in regulating prices for regional customers, and given that a significant number of large regional customers are supplied under notified prices, EEQ suggested that we should consider seeking expert advice to determine retail margins for each customer group. EEQ considered that this would be consistent with our approach to setting different allowances for other cost components, such as ROC. As we have previously acknowledged, there may be justification for adopting this approach, for instance on the basis of differences in risk between customer groups, but we consider that it is likely to be a highly subjective process. Nevertheless, we may reconsider this issue depending on the regulatory framework that will be established to regulate retail prices in regional Queensland.

We do not consider that the recent decisions of OTTER[22] and the ICRC[23] provide any new information because, as with ROC, both regulators applied a benchmarking approach to set the retail margin. We also note that there was no change in the margin adopted by IPART between its draft and final reports.

QCA position

We consider that it is appropriate to continue to set the retail margin at 5.7% for 2014–15.

4.2.3 Applying the retail margin to retail tariffs

For our 2012–13 and 2013–14 Determinations, we 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, high-use customers would pay more than low-use customers. We considered that this approach was appropriate because the retail margin is calculated as a percentage of total costs.

EEQ and EnergyAustralia supported a continuation of this approach for 2014–15. We agree and do not consider that there is sufficient evidence to suggest that an alternative approach would be more cost-reflective.

Conclusion on retail margin

We have set the retail margin at 5.7% of total costs, inclusive of the margin, and have applied it equally (on a percentage basis) to each component of each retail tariff.

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[22] OTTER, *Report on the investigation of maximum prices for interim price-regulated electricity retail services for small customers on mainland Tasmania, Report, July 2013; and OTTER, Statement of Reasons on Changes to the Interim Price-regulated Retail Service Price Determinations*, December 2013.
[23] ICRC, *Standing offer prices for the supply of electricity to small customers, Draft Report,* February 2014.

5 COMPETITION AND OTHER ISSUES

5.1 Competition considerations

We remain of the view that it is appropriate to include an allowance for headroom to support competition in south east Queensland for residential and small business customers and to promote competition outside south east Queensland for large business customers.

We consider that competition in south east Queensland is relatively effective and there are indications that it may have improved since the 2013–14 Determination was released. Competition is still limited for large business customers in regional Queensland and does not appear to have significantly improved, even with the introduction of more cost-reflective retail tariffs in 2012–13. There are other factors that may be preventing the development of competition in regional Queensland, for instance, the inability of large business customers on market contracts to revert to notified prices, the UTP arrangements and the availability of transitional and obsolete tariffs, which are below cost-reflective levels.

Consistent with our 2013–14 Determination, we have made an allowance for headroom of 5% of the estimated efficient costs of supply for all retail tariffs.

5.1.1 Introduction

Under the Delegation and section 90(5)(a) of the Electricity Act, we are required to have regard to the effect of our price determination on competition in the Queensland retail electricity market.

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 in 2007, although it is largely limited to south east Queensland as a result of the Government's UTP. In south east Queensland, most customers (around 70%) are supplied under a competitive market contract. In contrast, the vast majority of customers in regional Queensland (around 99%) are supplied under a standard contract and pay notified prices.

Where competition is effective, it generally provides the best means of delivering the goods and services that customers demand at prices that reflect efficient costs. Regulation will almost always be an imperfect substitute for competition because:

- it can distort incentives for businesses to compete and innovate
- regulators have imperfect information upon which to determine efficient costs and prices
- regulated prices are not as responsive to changes in costs as competitively-determined prices.

Following a recommendation from the Interdepartmental Committee (IDC) on Electricity Sector Reform, the Queensland Government announced that it will replace retail price regulation with price monitoring in south east Queensland by 1 July 2015, if certain conditions relating to customer protection and engagement are met. The Queensland Government expects that this will increase competition, resulting in better outcomes for customers in terms of choice, efficiency and customer service[24]. Price regulation will be retained in regional Queensland because competition is limited. However, the Queensland Government is considering options for improving competition, including moving towards a network-based subsidy within three years[25]. We provided advice to the Minister on issues relating to the UTP and regional price regulation on 30 April 2014.

Consistent with the 2013–14 Determination, we consider that a key objective of notified prices is to facilitate the development of competition in the Queensland retail electricity market and to provide a transition to price deregulation, particularly in south east Queensland. In our previous two price determinations, we have aimed to achieve this objective by:

- estimating the efficient costs of supply and setting notified prices on a cost-reflective basis
- adding an explicit allowance for excess profit or 'headroom' in notified prices above the estimated efficient costs of supply.

5.1.2 2013–14 Determination on headroom

In our 2013–14 Determination, we included an explicit allowance for headroom of 5% of the estimated efficient costs of supply in all retail tariffs. This was the same level of headroom included in the 2012–13 Determination.

We decided that the headroom allowance should be maintained at 5% based on an assessment of the state of competition in south east Queensland, the expected effects of other aspects of the price determination on competition, and the impact on customers that do not have access to, or choose not to take up, competitive market offers.

Our assessment of the state of competition revealed that, on several measures, the level of competition appeared to have been maintained or improved. We also acknowledged that declining switching rates and indications from some retailers that they were no longer actively marketing in Queensland may have indicated that competition had slowed.

However, we did not consider that there was sufficient evidence to suggest that competition was declining in south east Queensland. We also noted that, even if competition was declining, it would be difficult to determine whether (and to what extent) any decline was driven by our 2012–13 Determination or the Queensland Government's decision to freeze tariff 11 in 2012–13.

5.1.3 Should there be an allowance for headroom?

Retailers supported the inclusion of a headroom allowance. QCOSS and Queensland Consumers' Association objected to the inclusion of headroom because it increases prices for customers who do not have the option of, or choose not to take up, a market contract and because the south east Queensland market would remain competitive without it. QCOSS also suggested that retailers should enter the market because they are more efficient than incumbents, not because a headroom allowance increases prices above efficient levels.

[24] Queensland Government, *Response to the Interdepartmental Committee on Electricity Sector Reform*, June 2013; p. 9; and Minister for Energy and Water Supply, The Honourable Mark McArdle, *Media Release: End of electricity price regulation to improve competition*, 17 June 2013.

[25] Department of Energy and Water Supply, *The 30-year electricity strategy, Discussion paper*, September 2013, p. 10.

We still consider that an allowance for headroom is justified to support competition. As we have previously argued, competition is still largely price driven, so retailers compete by offering a discount to the notified price to attract customers 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.

The Australian Sugar Milling Council (ASMC), Cotton Australia and QFF objected to the inclusion of headroom because there is a limited prospect of successful competition in regional Queensland. We acknowledge that competition is extremely limited for most regional customers, although there is some competition in the large customer segment (see below). Nevertheless, most regional customers benefit from notified prices that are still lower than the actual costs of supply, as a result of the UTP.

QCOSS suggested that by including headroom the QCA has not complied with the Delegation, which requires that prices reflect costs. QCOSS and Canegrowers Isis suggested that headroom was not a valid cost component. Similarly, Canegrowers suggested that headroom does not reflect the cost of supplying irrigators. We agree that headroom is not a cost. However we still consider that an allowance for headroom is justified to support competition and can therefore be included in notified prices according to the requirements for setting prices set out in the Electricity Act[26].

We consider that including a reasonable level of headroom in retail tariffs strikes an appropriate balance between promoting competition, while recognising that some customers do not have access to, or choose not to accept, a competitive market offer.

The QCA's position

We have continued to include an allowance for headroom, above our estimate of the efficient costs of supply, to ensure competition is maintained in south east Queensland for residential and small business customers and to promote competition for large business customers outside of south east Queensland.

5.1.4 How much headroom?

As noted above, retail tariffs currently include an allowance for headroom of 5% of the estimated efficient costs of supply. We have considered whether headroom is set at an appropriate level to provide sufficient incentive for retailers to compete to acquire and retain customers and for customers to exercise market choice and seek out the best deal.

Residential and small business customer tariffs

To inform our decision about the level of headroom to include in residential and small business customer tariffs, we assessed the state of competition in south east Queensland, including the impact of our 2013–14 Determination (to the extent possible). Under the UTP arrangements, any reasonable level of headroom would be insufficient to encourage retailers to offer market contracts to the majority of residential and small business customers outside of south east Queensland.

[26] Section 90(5)(a) of the Act requires the QCA to have regard to the actual costs of making, producing or supplying the goods or services and the effect of the price determination on competition in the Queensland retail electricity market. Section 90(5)(b) allows the QCA to have regard to any other matters it considers relevant.

There was general support in submissions to continue with the approach to assessing competition that we adopted last year, where we considered the following factors:

- switching rates
- the number of active retailers and degree of market concentration
- available market offers
- customer participation and engagement.

ERAA suggested that competition in south east Queensland was effective. Some retailers acknowledged that there were some positive signs that competition was starting to improve. For instance, Origin Energy considered that the 2013–14 Determination was likely having a positive impact on competition, particularly because it recognises more realistic allowances for ROC, the retail margin and prudential requirements. Origin Energy also suggested price regulation was the only remaining barrier to effective competition in south east Queensland. However, ERM Power and QEnergy considered that notified prices were too low and were negatively impacting competition.

Retailers generally agreed that competition would significantly improve if prices were deregulated and welcomed the Queensland Government's announcement that it intends to replace price regulation with price monitoring in south east Queensland by mid-2015.

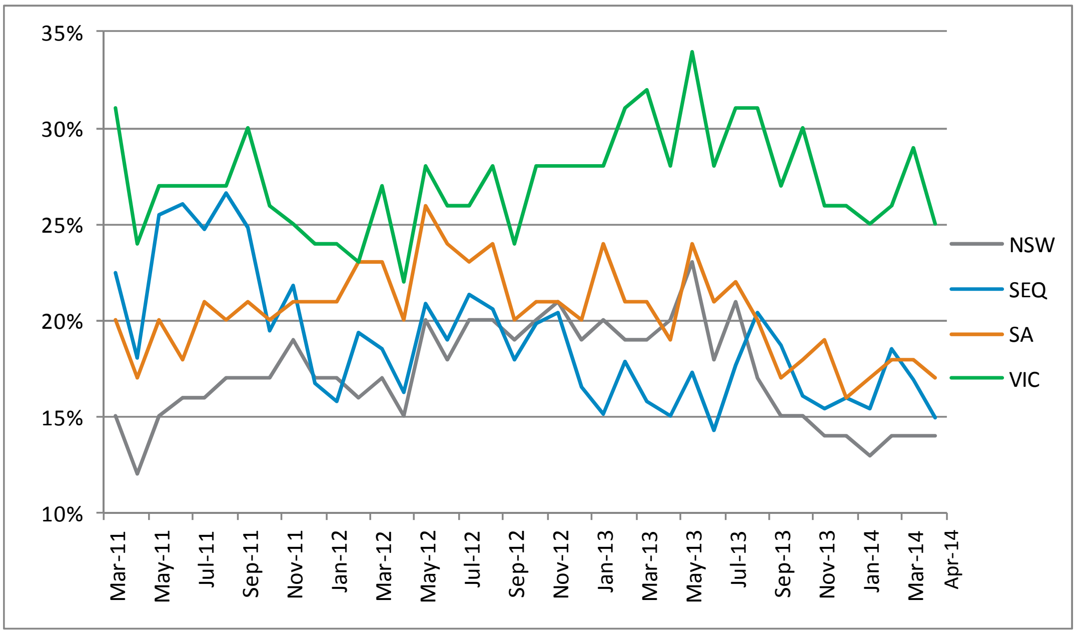
Switching rates

Retailers have previously argued that switching rates provide the most useful indicator of the level of competition in a market. In the 2013–14 Determination, we acknowledged that switching rates had been declining in recent years and that this may have indicated that competition had slowed. However, we have also previously noted that switching rates are one indicator of competitiveness, but are not the only indicator, nor necessarily the best.

AGL and QEnergy suggested that switching rates were low, which indicated that the level of competition was not strong, while ERAA, Origin Energy and EnergyAustralia acknowledged that switching rates had increased in recent months.

AEMO publishes switching rates for Queensland, NSW, South Australia and Victoria. As the Queensland switching rate is significantly impacted by the inclusion of customers in the Ergon Energy area, we have removed Ergon Energy's customers from the calculation to show how the south east Queensland switching rate compares to other states since March 2011.

Figure 5 Monthly annualised switching rates in south east Queensland and other states



Source: AEMO Monthly Retail Transfer Statistics; retailer data provided to the QCA.

Switching rates can change quite significantly from month to month, making it difficult to identify clear trends. As noted by Origin Energy, variation in switching rates can occur due to seasonal and other factors unrelated to underlying levels of competition.

Based on the first 10 months of 2013-14, the average switching rate in south east Queensland in 2013–14 is 17%, down slightly from the average rate of 18% in 2012–13. The average switching rate has decreased in NSW (from 20% in 2012–13 to 15% in 2013–14), South Australia (from 22% to 18%) and in Victoria (from 29% to 28%). In April 2014, the annualised south east Queensland switching rate was 15%, which was higher than in NSW (14%), but lower than in South Australia (17%) and Victoria (25%). At current switching rates, south east Queensland would be considered a very active market by international standards[27].

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 the 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 and/or smaller retailers are expanding their market share, this suggests that the market is attractive to new entrants and that barriers to entry or expansion are relatively low.

There are 14 retailers supplying residential and small business customers in Queensland. This is down from 15 when we published our 2013-14 Determination, because AGL purchased Australian Power and Gas (APG) in October 2013[28]. The market share of second tier retailers in south east Queensland has generally increased over the last couple of years, as shown in Figure

[27] VaasaETT, *World Energy Retail Market Rankings, 2012*, June 2012, p. 11.

[28] http://www.agl.com.au/about-agl/media-centre/article-list/2013/oct/aglstakeoverofferclosed, accessed on 1 May 2014.

6. It has increased since the release of the 2013–14 Determination, from 16.6% in June 2013 to 17.4% in March 2014, even with the recent transfer of APG's customers to a first tier retailer.

Figure 6 South east Queensland market shares: incumbent vs second tier retailers

Source: QCA analysis of retailer data.

QEnergy highlighted that it was not actively seeking customers in Queensland because notified prices were too low, while Alinta Energy stated that it was only making offers to large unregulated business customers for the same reason. QEnergy suggested that advertising activity by retailers as a whole was low. Although it is not possible to verify these claims, we note that the purpose of including an allowance for headroom is to support or promote competition, not to ensure that individual retailers have a viable business.

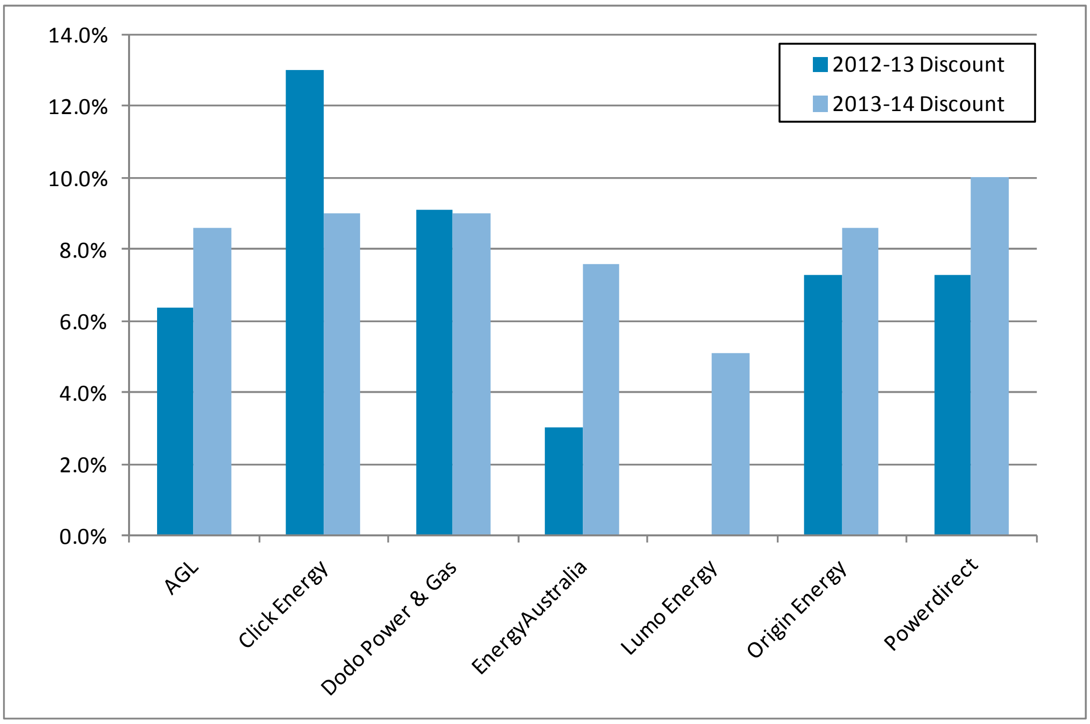
Market offers

As competition between retailers is still mostly price based, the extent and level of discounting by retailers can provide another indication of the state of competition. While we do not have access to information on the market offers available to business customers, there are 66 supply offers[29] available to residential customers, consisting of offers for both 'standard' electricity supply and 'green' electricity supply. These market offers provide customers with a range of contractual terms and conditions combined with other incentives[30]. Of the 66 supply offers available, 39 offer prices lower than the tariff 11 notified price.

A comparison of the best generally available discounts offered by retailers to residential customers in 2012–13 and 2013–14 is presented in Figure 7[31].

[29] As at 8 May 2014.
[30] These can include pay on time discounts, cash rebates for joining a retailer, retailer-funded feed-in tariffs, points for loyalty schemes and offers with no fixed term.
[31] We have excluded Simply Energy's market offer (which provides a 12% discount off usage charges) because it is only available to RACQ members.

Figure 7 Discounts offered to residential customers (percentage off total bill)



Source: QCA's price comparator, accessed 8 May 2014. Discounts are relative to tariff 11 notified prices. Where the discount is applied to the usage component only and/or cash rebates are offered, the total discount is calculated assuming typical annual consumption of 4,100 kWh. Excludes offers to solar PV customers. In 2012–13, Lumo Energy offered frequent flyer points and green energy instead of discounts.

Most retailers' discounts are larger in 2013–14 than 2012-13, although the maximum discount is 10%, which is lower than in 2012-13 (13%). These discounts reflect a point in time only. Retailers operating in a competitive market would be expected to review and change their offers, including in response to their competitors' offers. We note that retailers have been making changes to the offers on the QCA's price comparator more regularly this year than they have in the past.

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. A lack of customer engagement is a recognised issue in retail electricity markets, even in those markets that do not have price regulation.

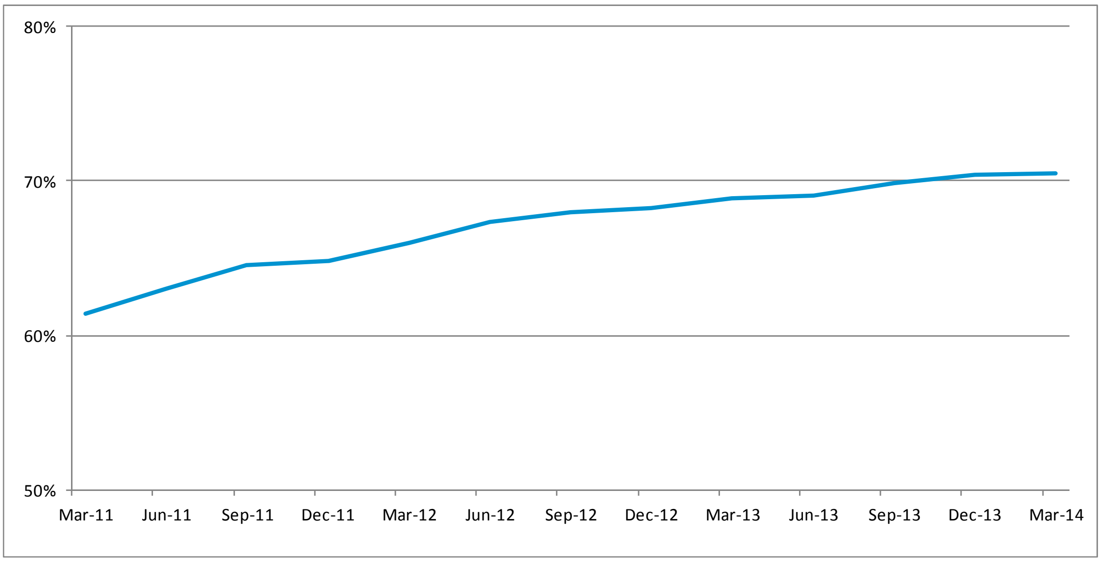
While we consider that a lack of customer engagement in the retail electricity market may indicate that competition is not as effective as it could be, higher electricity prices in recent times may be providing some impetus for customers to become more proactive in securing a better deal. For example, over 73,000[32] customers signed up to the 'Big Queensland Electricity Switch' campaign, which aimed to use the power of group switching to negotiate a better electricity deal. The Queensland Government is also considering ways to increase customer engagement[33].

[32] Source: https://www.onebigswitch.com.au/campaigns/big-qld-electricity-switch, accessed 8 November 2013.

[33] Department of Energy and Water Supply, *The 30-year electricity strategy, Discussion paper*, September 2013.

As shown in Figure 8, the percentage of customers on market contracts has generally been increasing since March 2011, which suggests that retailers are offering sufficient inducements to encourage customers to move from a standard contract to a market contract. As at 30 March 2014, 70.5% of south east Queensland electricity customers were supplied under a market contract, up from 69.1% in June 2013.

Figure 8 Proportion of south east Queensland customers on market contracts



Source: Data provided by retailers. One retailer advised that they mistakenly classified a large number of customers as market, rather than non-market, from the March quarter 2011 to the September quarter 2013. The retailer corrected this error for the December quarter 2013 by reclassifying around 20,000 customers. While we have asked the retailer to correct historic data, in the meantime, we made our own adjustments to previous quarters on the assumption that 20,000 customers have been incorrectly classified every quarter.

QCA position

AGL, EnergyAustralia, ERAA and Origin Energy supported maintaining headroom at 5% and AGL noted that this figure was consistent with the level of headroom that IPART included in its most recent price determination. ERM Power and QEnergy suggested that a headroom allowance of 5% was too low. In contrast, the ASMC suggested that headroom should not be increased, while QCOSS suggested that there should be no headroom allowance, but that if there was, it should be as low as possible.

We consider that competition in south east Queensland is relatively effective and there are indications that it may have improved since the 2013-14 Determination was released. For instance, the market share of second tier retailers and the proportion of customers on a market contract have both increased, while most retailers' discounts are higher than last year (although the maximum discount is lower). There is relatively little change in the other indicators.

However, as we have previously pointed out, other factors can impact on competition that are largely outside our control. It can be difficult to isolate the impact of our determinations from these other factors, which may include:

- *The relative attractiveness to retailers of the markets that have price regulation compared to markets that do not*. However, the Queensland Government's announcement that it is considering deregulating retail electricity prices in south east Queensland by mid-2015 may have improved the relative attractiveness to retailers of the south east Queensland market and positively impacted competition.

- *Government intervention in the price-setting process, which may increase the perceived risk of retailing in Queensland*. Retailers have previously argued that the Queensland Government's decision to freeze tariff 11 in 2012–13 increased uncertainty and the risk of retailing in Queensland[34]. The Queensland Government also intervened in the price-setting process in 2013–14 by capping the increases in the obsolete and transitional tariffs at 10%, which is lower than the increases we set.
- *Metering technology limitations*. As pointed out by the IDC on Electricity Sector Reform, limited metering functionality can negatively impact on competition by inhibiting product innovation and limiting the choice of products retailers can offer customers[35]. However, we note that the Government recently announced that it endorsed a customer-driven rollout of advanced meters[36].
- *Barriers to customer engagement and participation in the competitive market*. As noted above, while the level of notified prices may provide some incentive for customers to engage in the competitive market, we understand that the Government is establishing a working group to develop a strategy to improve customer engagement[37].

We consider that it is appropriate to maintain the headroom allowance at 5% of cost-reflective prices for residential and small business customer tariffs.

Large business customer tariffs

As discussed in Chapter 2, notified prices for large business customers are based on Ergon Energy's network charges because large business customers in Energex's network area no longer have access to notified prices. Therefore, notified prices are more cost-reflective than they have been in the past.

In order to assess the state of competition for large regional customers, EnergyAustralia suggested conducting a survey because most commonly available measures are too high-level to produce useful information about this sub-group of customers. No other submissions discussed this issue.

Although it is difficult to assess the impact of more cost-reflective notified prices on competition, we note that, in a submission to the 2013–14 price review, AGL indicated that it has been active in providing competitive market offers to these customers since the introduction of more cost-reflective tariffs. However, there has only been a small increase in the proportion of large regional customers on market contracts since more cost-reflective notified prices were introduced in 2012–13. As at 31 March 2014, around 27% of large regional customers were supplied under a market contract, compared to around 25% in June 2012.

We consider that, even if headroom is set at an appropriate level, other barriers to competition remain. For instance:

(a) as discussed in Chapter 2, notified prices are based on:

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[34] 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.
[35] Interdepartmental Committee on Electricity Sector Reform, *Report to Government*, May 2013, p.60.
[36] DEWS, *The 30-year electricity strategy, Discussion paper*, September 2013, p. 12.
[37] *Ibid*., p. 10.

(i) network charges for Ergon Energy's east pricing zone, transmission zone one, meaning that customers in other pricing zones are not paying cost-reflective retail tariffs

(ii) for very large business customers, the network charge for high voltage demand customers rather than each customer's site-specific network charge

(b) many customers are still accessing obsolete and transitional tariffs, which are set below cost-reflective levels

(c) once large business customers accept a market contract they cannot revert to a standard contract (paying notified prices), which may discourage them from accepting a market offer[38].

QCA position

Competition for large regional customers is still in its early stages and there are indications that the introduction of more cost-reflective notified prices has had a limited effect on competition so far. However, we have identified barriers to competition that we consider will remain even if headroom is set at an appropriate level.

We do not consider that including a different level of headroom to that included in residential and small business customer tariffs is justified. Therefore, we will maintain the headroom allowance at 5% of the estimated efficient costs of supply for all large business customer tariffs.

5.1.5 Conclusion on headroom

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

5.2 Accounting for unforeseen or uncertain events

As the QCA determines notified prices based on estimates of the costs to be incurred by retailers, the actual costs incurred by retailers in a given year can differ from those allowed for in notified prices. Cost pass-through mechanisms allow certain costs or savings incurred during a particular tariff year to be passed through in notified prices in subsequent years.

In the Draft Determination, we proposed to consider adjusting 2014–15 notified prices to account for differences in:

- small-scale renewable energy scheme (SRES) costs, where the amounts allowed for in 2013-14 notified prices are found to be materially under- or overstated as a result of differences between non-binding and binding small-scale technology percentages (STPs)
- network charges, in the event that the final charges billed to retailers (usually the AER-approved charges) differ from those used to set notified prices.

We also considered that it was not necessary to prescribe a fixed materiality threshold, and that each event should be considered on its merits.

Submissions

Stakeholders' views on a cost pass-through mechanism for 2014-15 were mixed. The ERAA, retailers (AGL, Alinta Energy, Energy Australia, and Origin Energy) and the distributors (Energex

[38] This restriction also applies to any future occupants of that premises (for example, if the premises is sold or occupied by a new tenant).

and Ergon Energy) generally supported a cost pass-through mechanism for 2014–15, while consumer groups such as Canegrowers and the ASMC did not.

Despite supporting a cost pass-through mechanism, AGL, EnergyAustralia and the ESAA submitted that cost pass-throughs should not be limited to certain events. AGL and EnergyAustralia suggested that limiting the pass-through mechanism to differences in SRES costs and network charges would be a poor regulatory framework in the long-term, but noted that the current review is focussed on 2014–15 and that any pass-through is only relevant to the current financial year. EEQ suggested that pass-through provisions may also need to be used in 2015–16 to account for any significant, unpredictable movements in the carbon price and/or carbon legislation during 2014-15.

QEnergy suggested that the pass-through mechanism should also apply to incorrect forecasts of renewable energy target (RET) percentages for previous determinations, in addition to the 2013–14 Determination. QEnergy also argued that the price used for STCs for the 2013–14 Determination should be re-opened to reflect the fact that it has increased from the start of the determination period to a level very close to the clearing house price of $40.

AGL and the ESAA agreed with our Draft Determination that pass-through events should not be bound by a materiality threshold. The ESAA noted that materiality thresholds are highly subjective, particularly in isolation of other elements to which retailers are exposed. The ESAA suggested that any change in costs will influence the ability of retailers to offer discounts below the regulated price, and it is therefore appropriate that cost pass-through proposals are assessed on their merits. In contrast, QCOSS preferred a firm materiality threshold to ensure a transparent calculation of cost pass-throughs.

Consumer groups, the ASMC and Canegrowers did not support the inclusion of a cost pass-through mechanism. Canegrowers argued that retailers are already being compensated for the level of risk inherent in the retail electricity market, with allowances provided for margin, retail operating costs and headroom, while the ASMC argued that retailers are expected to have their own risk management strategies to account for the costs associated with unforeseen and uncertain events.

The ASMC added that, in extreme situations, the Government should step in to assist retailers in the form of an equity transfer, rather than allowing retailers to pass-through the additional costs to consumers. However, this is a matter for the Government.

Approaches in other jurisdictions

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

In its 2012–14 determination, the Independent Competition and Regulatory Commission (ICRC) in the ACT included pass-through arrangements for regulatory change events and tax change events. To be passed through, an unforeseen cost or saving must translate to an impact on ActewAGL Retail's revenue from regulated retail tariffs (during the most recent 12-month period) of more than 0.25%[39].

[39] ICRC, *Final Report: Retail prices for franchise electricity customers - 2012-14*, 8 June 2012, pp. 34-37. The ICRC has proposed to largely maintain the same approach in its 2014-17 draft decision, but to allow for the adjustment of regulated prices at any time from 1 July 2014 if the carbon tax is repealed. See ICRC, *Draft*

Similarly, in NSW, IPART included a cost pass-through mechanism in its 2013–16 retail price determination to allow standard retailers to pass-through material increases (and decreases) in costs for defined regulatory or taxation change events that were not anticipated, or were uncertain, at the time of the determination. IPART applied a materiality threshold of 0.25% of the standard retailers' total revenue from regulated retail prices for the year in which the event occurs.

In South Australia, ESCOSA's 2010 price path determination allowed AGL SA to seek the pass-through of costs for particular events that are outside the control of AGL SA. However, since 1 February 2013, retail electricity prices in South Australia have been deregulated. As a result, the pass-through provisions in ESCOSA's 2010 determination are no longer required.

OTTER[40] included cost pass-through provisions in its 2013 determination on retail standing offers for small customers, for the period from 1 January 2014 to 30 June 2016. OTTER allowed for the pass-through of differences in estimated and actual network charges, RET costs and AEMO fees and charges.

QCA position

Under the N+R approach to calculating notified prices, many significant changes in retailers' costs will automatically be reflected in the inputs used to develop regulated tariffs. Combined with the annual frequency of tariff determinations, the current price setting framework in Queensland inherently captures the cost impact of many events, some of which may otherwise require cost pass-throughs under longer-term price determinations.

However, consistent with our Draft Determination, there are two categories of costs identified in the 2013–14 Determination that are beyond the control of retailers that we consider should be eligible to be passed-through:

- differences in network charges, in the event that the charges billed to retailers (usually the AER-approved charges) differ from those used to set notified prices
- differences in SRES costs, where the amounts included in the determination are found to be materially understated or overstated as a result of differences between the non-binding and binding STPs.

We consider that limiting the use of the pass-through mechanism to these two situations strikes a reasonable balance between concerns about the potential for regulatory gaming (previously raised by customers and consumer groups) and the expectation that retailers should have the opportunity to recover the efficient incremental costs of certain exogenous events, over which they have no control. The mechanism is also symmetrical, so it will capture events that result in an over-recovery of costs.

We disagree with the claims of the ASMC and Canegrowers that retailers are already compensated for risks associated with unforeseen or uncertain events through other cost allowances. As discussed in our 2013–14 Determination, one of the principles underlying the cost pass-through mechanism is that pass-through costs should not have already been provided for in the various cost components or, for example, through the retail margin. The retail margin

Report - Standing offer prices for the supply of electricity to small customers, 1 July 2014 to 30 June 2017, February 2014.

[40] Office of the Tasmanian Economic Regulator, *Report on the investigation of maximum prices for interim price-regulated electricity retail services for small customers on mainland Tasmania*, July 2013.

compensates retailers for systematic risks associated with supplying electricity to customers, not the risks associated with changes to SRES and network costs, which are specific to the retail electricity industry (see Chapter 4).

While consumer groups considered that the costs associated with unforeseen and uncertain events should be addressed via retailers' own risk management strategies, accepting or managing risk comes at a cost and retailers would expect to be compensated for this. One approach would be to include a premium in the network and energy cost allowances to compensate retailers for accepting the risk of actual network charges and SRES costs differing from those used to set notified prices, although this would increase prices. We have decided to account for the risk of these events occurring through a cost pass-through mechanism, which means that customers will only pay if the event occurs.

We have calculated notified prices based on energy costs that are fully inclusive of carbon costs, to apply while the carbon tax remains in place, and then expect to re-determine carbon-exclusive prices during 2014–15 if and when the carbon tax is removed. This approach will remove the need for any pass-through of carbon costs or savings in 2015–16, as suggested by EEQ (see Chapter 3).

With regard to a materiality threshold, we maintain our view that it is not necessary to prescribe a firm threshold, and have considered each proposed cost pass-through trigger on its merits, in conjunction with other relevant factors.

Assessment of cost pass-throughs for 2014–15

Accounting for differences between estimated and approved network charges

The final 2013–14 network charges approved by the AER and charged to retailers did not differ from those used to set 2013–14 notified prices. Therefore, no pass-through adjustment for network charges is required in 2014–15 notified prices.

Accounting for differences in SRES compliance costs

As discussed in Chapter 3, a retailer's SRES liabilities are determined by the STP, which is the prescribed value that retailers use to determine the number of STCs they must surrender to discharge their SRES liabilities. The STP is set by the Commonwealth Government (the Clean Energy Regulator, CER) and changes from year to year.

Retailers incur SRES liabilities for each calendar year, but notified prices are determined for each financial year. While the binding STP for the first and second quarters of the prospective financial year is known when setting notified prices, the binding STP for the third and fourth quarters is not. To overcome this, ACIL Allen estimated SRES costs using the average of the binding STP (for the first two quarters of the financial year) and a preliminary or 'non-binding' STP (for the last two quarters of the financial year). Where the binding STP for the last two quarters turns out to be different from the non-binding STP, the SRES allowance may under- or over-compensate retailers for their actual SRES liabilities.

We do not accept QEnergy's suggestion to adjust 2014–15 prices for under-recoveries incurred in years prior to 2013–14. As foreshadowed in the 2013–14 Determination, we have only contemplated the pass-through of additional incremental SRES costs incurred during 2013–14 in 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, we consider that the recovery of any such costs should occur during a tariff year within the current Delegation period.

We also disagree with QEnergy's suggestion to reopen the estimated STC price as part of the pass-through calculation. For 2013–14, we accepted ACIL Allen's use of the clearing house price for STCs, on the basis that alternative market data is not always readily (or publicly) available and the expectation that any differences between market prices and the clearing house price would diminish over time. We maintain this view.

There was a difference between the 2014 binding and non-binding STPs, so we have assessed whether the resulting difference in SRES compliance costs should be passed-through in 2014-15 notified prices.

Assessment

Retailers with regulated customers are unlikely to fully recover the costs of complying with the SRES for 2013–14 because the non-binding STP target of 8.98% for the second half of 2013–14 was lower than the binding STP target of 10.48%[41]. However, as set out in our 2013-14 Determination, for an event to be considered for pass-through, the incremental impact of the cost should generally be demonstrated to be material. The intention is not to allow retailers to recover relatively minor unforeseen costs that would typically be absorbed by an efficient, competitive retailer.

In order to determine materiality, we first calculated the under-recovered amount using the following approach (as set out in our Draft Determination):

(1) recalculate the actual cost of SRES compliance during 2013–14, in terms of cents per kilowatt hour (c/kWh), based on the binding STP target for the 2014 calendar year

(2) subtract the SRES cost included in 2013–14 notified prices from the updated cost calculated in step 1

(3) adjust the value calculated in step 2 to account for transmission and distribution losses (energy losses) using the 2013-14 loss factors for each settlement class

(4) add an allowance to the value calculated in step 3 to account for the time-value of money (using a weighted average cost of capital (WACC) of 9.7% and CPI of 2.75%)

(5) add the value calculated in step 4 to the c/kWh SRES cost estimate for 2014–15, before applying retail margin (5.7%) and headroom allowances (5%).

More detailed information about the calculations is provided in Appendix J. Table 10 presents our assessment of the 2013-14 under-recovered amounts.

[41] The binding STP was published in March 2014. See: http://ret.cleanenergyregulator.gov.au/About-the-Schemes/About-the-small-scale-technology-percentage/About-the-small-scale-technology-percentage.

Table 10 SRES under-recovery in 2013-14 ($2014-15)

Settlement Class	***Retail Tariff***	***SRES under-recovery (c/kWh)***
Energex NSLP and unmetered supply	11,12,13,20,22,41,91	0.040
Energex Controlled Load 9900	31	0.040
Energex Controlled Load 9100	33	0.040
Ergon Energy - NSLP - SAC HV, CAC and ICC	47,48	0.041
Ergon Energy - NSLP - SAC demand and street lighting	44,45,46,71	0.043

Note: Under-recovered amounts include adjustments for energy losses, the time value of money, retail margin and headroom.

The next step is to consider the impact of the under-recovery on the returns of the retail businesses against the administration costs of passing through the under-recovered costs in notified prices.

EEQ has the largest number of non-market customers, so it is likely to face the greatest impact on its returns. The SRES under-recovery translates to a shortfall for EEQ of approximately $3 million or 4% of its 2012-13 reported profit[42]. The financial impact on other retailers is expected to be lower, amounting to a shortfall of around $1 million in total[43].

We consider that the potential pass-through amount is material because the impact on the returns of retailers (particularly EEQ) is sufficiently large, while the administration costs of adjusting notified prices are negligible, particularly because the adjustment will be made as part of the annual notified price change process[44]. We also note that the impact on customers is likely to be relatively minor. For example, the impact on a typical customer on tariff 11 would be less than $2.

Conclusion

We have decided to allow for the under-recovered costs associated with higher SRES compliance costs (see Table 10) to be passed-through to customers in 2014–15 notified prices.

5.2.1 Pass-through arrangements beyond 2014–15

The Queensland Government has stated its intention to deregulate retail electricity prices in south east Queensland from 1 July 2015. If this occurs, the pass-through of under- or over-recovered costs incurred during 2014–15 will be at the discretion of retailers when setting competitive market offers in south east Queensland, rather than captured through regulated prices.

However, despite the potential removal of direct retail price controls in south east Queensland after 2014–15, there will likely still be a need to establish regulated retail prices for customers in

[42] Ergon Energy Corporation Limited, *Subsidiary Financial Statements for the year ended 30 June 2013*, August 2013.

[43] Based on 2012-13 consumption data and assuming that 30% of consumption by small customers is by non-market customers.

[44] The annual adjustment we make to the ROC allowance to account for the regulatory fees that retailers pay the QCA is of a similar magnitude (around $2.8 million in total for 2014-15) and the administration costs of estimating and including regulatory fees in notified prices are also low (see Chapter 4).

the Ergon Energy distribution area, at least until there is effective competition. Depending on the form of price regulation that the Queensland Government applies in regional Queensland after 2014–15, the pass-through provisions and trigger events discussed here may or may not remain relevant for price setting in regional Queensland.

5.3 Other issues

A number of submissions raised issues which, while relevant to electricity pricing in general, are outside the scope of this price review.

Large customer threshold

Canegrowers Isis suggested that all farmers should be classified as small customers and questioned the process by which customers are categorised as small or large. The small/large customer threshold is defined in the Electricity Regulation and cannot be changed by the QCA.

Application of the CSO

Some stakeholders suggested that the Queensland Government's community service obligation (CSO) subsidy paid to EEQ should instead be paid to Ergon Energy's distribution business, to allow retail competition to develop in regional areas.

Any change in CSO policy is a matter for the Queensland Government. As outlined in its discussion paper on the 30-year electricity strategy[45], the Queensland Government is considering options for improving competition in regional Queensland, including the possibility of moving to a network-based CSO within three years.

Related to this, after a round of public consultation, we have provided advice to the Minister on the efficiency and effectiveness of the UTP, options for maintaining the UTP and approaches to setting notified prices in regional Queensland (once price monitoring commences in south east Queensland). Further information is available on our website (www.qca.org.au).

Government concessions

The ESAA suggested that, as part of the move to cost-reflective pricing, the electricity rebate paid by the Queensland Government could be better targeted, as the rebate in its current form failed to adequately protect vulnerable consumers. The Queensland Government is examining the eligibility criteria and structure of the electricity rebate as part of the 30 year electricity strategy. Further information is available from the Department of Energy and Water Supply website (www.dews.qld.gov.au/policies-initiatives/electricity-sector-reform).

Solar photovoltaic issues

The Clean Energy Council raised a number of issues relevant to solar photovoltaic customers. However, the Delegation requires the QCA to determine notified prices for customer retail services, which are defined under the Electricity Act as the sale of electricity to customers. Therefore, the issues raised are outside the scope of this review.

[45] Department of Energy and Water Supply, The 30-year electricity strategy, Discussion paper, 11 September 2013, p. 10, available from: http://dews.qld.gov.au/policies-initiatives/electricity-sector-reform/discussion-paper.

Impact of the solar bonus scheme

Submissions from customer and farming groups highlighted the impact of the Solar Bonus Scheme (SBS) on electricity prices. Farming groups argued that they should not bear the costs associated with the SBS as they do not benefit from the scheme. SBS costs are recovered by distributors through network prices, which are approved by the AER and are outside the scope of this review. The AER is conducting a consultation process on the 2015-2020 electricity distribution determination and we encourage stakeholders to participate in that process. Further information is available on the AER website (www.aer.gov.au).

6 TRANSITIONAL ARRANGEMENTS

The Delegation requires that the QCA consider implementing appropriate transitional arrangements for tariff 11, and the tariffs classed as obsolete in 2012–13 should it consider that customers on these tariffs would face significant price impacts if they were required to move to the alternative cost-reflective tariffs immediately.

Having considered stakeholders' submissions and updated data on customer impacts provided by Ergon Energy, we have decided not to change the approaches to transitional arrangements established for 2013–14 and therefore propose to:

- continue with the three-year transitional arrangement to rebalance the fixed and variable components of the standard regulated residential tariff (tariff 11) so they are cost-reflective by 1 July 2015
- maintain transitional arrangements for tariffs classed as obsolete in 2012–13 (which includes farming, irrigation, declining block, non-domestic heating and large business customer tariffs), where there would be significant price impacts for customers moving to alternative cost-reflective tariffs
- continue to allow all customers access to transitional tariffs.

6.1 Re-balancing the fixed and variable charges in tariff 11

The Delegation requires the QCA to consider implementing a three-year transitional arrangement to rebalance the fixed and variable components of tariff 11 so they are cost-reflective by 1 July 2015.

In 2012–13, the Queensland 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 we had estimated. To implement this decision, the Government directed Energex to lower the fixed component of its network charge to retailers for residential customers on tariff 11, 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 one year only (2012–13). These arrangements resulted in lower fixed[46] and higher variable charges than the cost-reflective charges we had estimated for tariff 11 in 2012–13.

On the basis of the cross-subsidies inherent in tariff 11 charges, and the potential these have to distort the retail market for electricity in Queensland, we implemented a three-step transition to cost-reflective tariffs, commencing in 2013–14. This was consistent with the requirement in the Delegation for transitioning to be completed by 1 July 2015.

Given that the fixed charge is below cost, and the variable charge is above cost, any transitional arrangement must involve gradual increases to the fixed cost component and offsetting reductions to the variable cost component[47]. This approach ensures revenue adequacy for

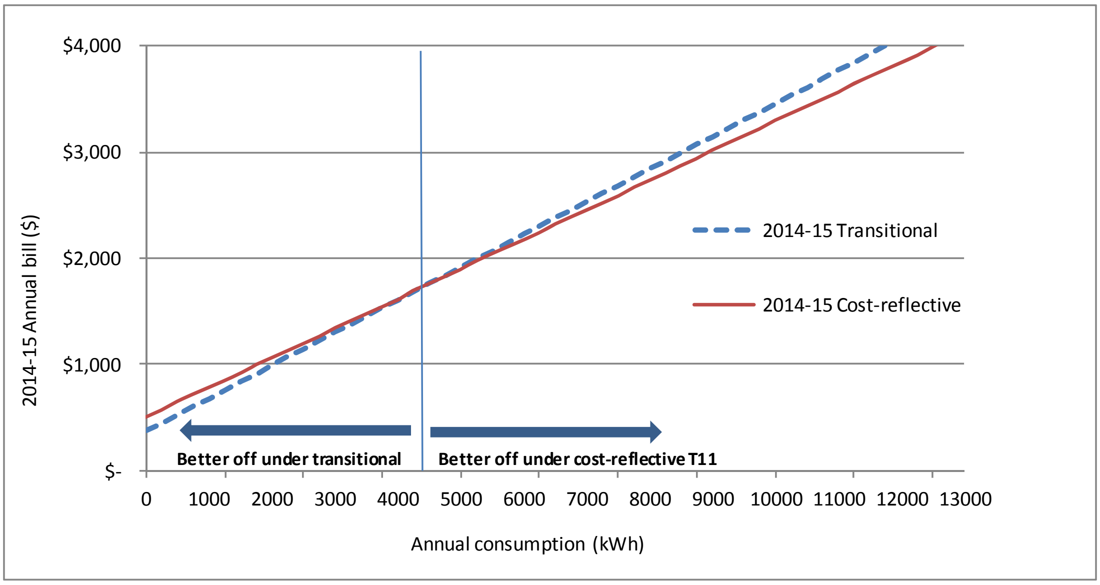
[46] Retailers may use different terms for this charge, including service fee, service charge, daily supply charge and service to property charge.

[47] Note that this assumes that there is no change in underlying costs from one year to another. If underlying costs increase, the variable cost component may actually increase.

retailers as charges move closer to cost reflectivity – or, in other words, retailer revenues stay the same, but the amount individual customers pay changes, according to their usage.

The staged approach to rebalancing the fixed and variable charges of tariff 11 means that customers with higher annual consumption will continue to cover the shortfall in revenue retailers incur from supplying customers with lower annual consumption (see Figure 9). This cross-subsidy will continue until tariff 11 charges are fully rebalanced to cost-reflective levels.

Figure 9 2014–15 Annual electricity bills based on cost-reflective and transitional prices



Submissions

AGL, EnergyAustralia and ESAA advocated moving to cost-reflective charges for tariff 11 as soon as possible. AGL and ESAA suggested this would reduce price confusion among customers and enable a smoother transition to price monitoring in south east Queensland, should retail price controls be removed from 1 July 2015. ESAA was of the view that holding tariff 11 below cost provides an unfair advantage to customers receiving the discounted rates and would delay customers from switching to more efficient tariffs.

Despite preferring a quicker move to cost-reflective charges, EnergyAustralia, Origin Energy and ESAA supported continuing with the three-year transitional arrangement implemented in 2013-14, although ESAA suggested that the rebalancing should minimise the adjustment required in the final year. The three year transitioning approach was also supported by the Queensland Government and QCOSS.

QCOSS urged the QCA to consider the impact of significant price increases on low income and disadvantaged customers. COTA suggested that the rebalancing exercise had resulted in inequitable increases to the fixed charge for residential customers with low levels of consumption.

QCOSS suggested the QCA needed to have close regard to changes in the structure and level of network charges when re-balancing the fixed and variable charges. ERAA recommended that potential changes to network cost structures be considered in the re-balancing exercise.

QCA position

As noted in the 2013–14 Determination, we consider that, from an economic perspective, an immediate transition to cost-reflective charges would be the ideal path to correct distortions in tariff 11. However, we also noted the requirement in the Delegation that suggested a three-year stepped approach was considered more desirable, with at least some rebalancing of fixed and variable charges each year. This approach was supported in submissions to the 2013-14 review from a number of stakeholders, including retailers.

While we recognise that price regulation in south east Queensland may be replaced by price monitoring from 1 July 2015, we are still required to rebalance the fixed and variable components of tariff 11 so that each component will be cost-reflective by 1 July 2015. In doing so, we maintain the view that the stepped approach implemented in 2013–14 strikes an acceptable balance between limiting increases in the fixed charge, to ease the financial pressure on customers with low levels of consumption, and moving the variable charge closer to cost, to reduce the cross-subsidy paid by customers with high levels of consumption.

We agree with QCOSS on the need to have close regard to changes in the structure and level of network charges when re-balancing the fixed and variable charges and have therefore based the re-balancing for 2014-15 on Energex's network charges for 2014-15, rather than continuing with the 2013-14 charges that were used when the re-balancing task commenced.

We disagree with ERAA's suggestion to consider potential future changes in network costs as these will not be known until Energex submits its revenue proposal for the next regulatory period to the AER.

As submissions did not provide any new reasons to justify a change in approach, we have decided to continue with the approach to transitioning tariff 11 that was established in the 2013–14 Determination. As there are only two steps left in the transition, the transitional fixed charge for 2014–15 is set halfway between the transitional 2013–14 fixed charge and the cost reflective 2014–15 fixed charge. The variable charge has been set at a level that ensures retailers are able to recoup their full costs from all tariff 11 customers (based on an average annual bill of $1,732)[48]. These values are presented in Table 11, which also shows indicative values for 2015–16 (in 2014–15 values).

Table 11 Transitional and cost-reflective charges for tariff 11 (based on constant 2014–15 costs[1])

Tariff component	*Transitional 2013-14*	*Final transitional 2014-15*	*Final cost-reflective 2014 -15*	*Indicative transitional 2015 -16*
Fixed charge[1] (cents/day)	50.219	83.414	116.609	116.609
Variable charge[1] (cents/kWh)	26.730	28.015	25.341	25.341
Annual bill[2,3] ($)	1,535	1,732	1,732	1,732

1 GST exclusive.
2 Based on Energex's forecast of average consumption by residential customers in 2014–15 of 4,533kWh per year.
3 GST inclusive.

[48] Based on Energex's forecast of average consumption by residential customers in 2014-15 of 4,533 kWh per year.

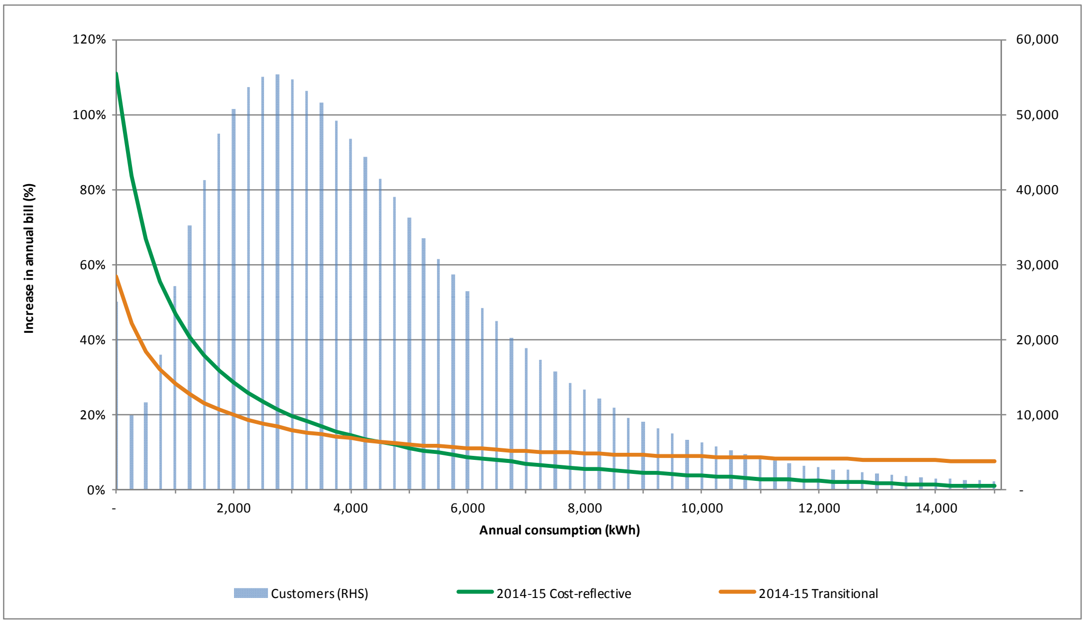
It must be recognised that the end target for the fixed component reflects 2014–15 costs and assumes nothing else changes over the remainder of the transitional period. As underlying network charges and other costs are likely to change in the future, the charges presented for 2015–16 are indicative only.

Customer impacts

The transitional charges for 2014–15 presented in Table 11 are higher than the transitional charges for 2013–14 and will increase an average residential customer's annual bill from $1,535 to $1,732 (based on average consumption for 2014–15 of 4,533 kWh per year). This increase is due to an increase in the underlying cost-reflective charges for tariff 11 between 2013–14 and 2014–15, as discussed in Chapter 7.

Figure 10 shows how much customers' annual bills will increase in percentage terms by moving from the transitional tariff 11 charges for 2013–14 to the transitional tariff 11 charges for 2014-15, across a range of consumption levels. As expected, the further a customer's level of consumption is below average, the larger will be the percentage increase in their bill.

Figure 10 Bill impacts resulting from moving to transitional and cost-reflective tariff 11 charges



Unfortunately, there is little scope for increasing the fixed charge by much less, because doing so would require an offsetting increase in the variable charge, which is still well above its cost-reflective level. While this approach to transitioning benefits customers with low levels of consumption, we are 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.

As noted previously, we would prefer to see prices set according to cost, and for the needs of financially stretched and vulnerable customers to be met via more targeted welfare assistance measures. A summary of assistance arrangements directly targeting energy costs is provided in **Appendix C** and it would be open to the Government to consider whether additional assistance measures may be appropriate for some customers facing higher cost increases.

Further analysis of the impacts on different types of customers is presented in Chapter 7. It is beyond the scope of the current exercise to provide suggestions to mitigate the effects of increasing electricity prices.

6.2 Transitional arrangements for obsolete and transitional tariffs

In 2012–13, the QCA 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 Delegation requires the QCA to consider implementing an appropriate transitional arrangement should we consider there would be significant price impacts for customers on farming, irrigation, declining block, non-domestic heating and large business customer tariffs if required to move to the alternative cost-reflective tariffs.

During consultation for the 2013–14 Determination, it became clear that the impacts to customers would be so great in many cases that further transitional arrangements would be appropriate.

For the 2013–14 Determination, we decided to:

- implement a seven-year transition for customers on tariffs 20 (large), 21, 22 (small and large), 37, 62, 65 and 66
- implement a two-year transition for customers on tariffs 41 (large) and 43 (large)
- remove three little-used tariffs (53 (large), 63 and 64).

In addition, for equity reasons, we opened access to tariffs 20 (large), 21, 22 (small and large), 62, 65 and 66 to all eligible customers over the seven-year transition period. The tariffs with opened access were classified as transitional and tariffs 37, 41 and 43 were classified as obsolete, either on the basis that they had been obsolete for some time (tariff 37), or because they will be removed in a shorter timeframe (tariffs 41 and 43).

The QCA set 2013–14 price increases for transitional and obsolete tariffs based on the percentage increases in the relevant cost-reflective tariffs that customers would otherwise be on, plus additional escalations to ensure the price differences between obsolete and cost-reflective tariffs did not widen over the transition period. However, these prices were overruled by the Queensland Government, which set prices for all transitional and obsolete tariffs 10% above the 2012–13 prices.

Submissions

In general, consumers and consumer groups advocated continuation of transitional arrangements, although they disagreed with the length of time allowed and the level of price increases included in the 2013–14 Determination and the 2014–15 Draft Determination.

Canegrowers Isis suggested that the seven-year transition period implemented in 2013–14 was not long enough. It argued that the farming and irrigation tariffs should remain indefinitely as there is no equivalent irrigation tariff offered by Energex on which to base a retail tariff. The Queensland Farmers' Federation (QFF) suggested that the seven-year transition period would be appropriate if tariff increases could be kept at manageable levels. However, it argued that setting prices under the terms of the Delegation resulted in price increases so large that seven years do not provide sufficient time for irrigators to adjust operations to prepare for cost-reflective pricing. In addition, the QFF expressed concern that the Ergon Energy tariff strategy review may not be completed within the seven-year transition period, and suggested this provided a further reason to extend the transition period.

The size of price increases for transitional and obsolete tariffs we proposed in the Draft Determination raised concerns for many stakeholders. Canegrowers Isis, Canegrowers, Cotton Australia, Pioneer Valley Water (PV Water), QDO and QFF argued that the price increase of 16.3% for irrigation tariffs could not be absorbed by their constituents. More specifically, Canegrowers disagreed with the 1.25 escalation factor applied to irrigation tariff increases as it is unrelated to underlying cost increases. Further, Canegrowers, Cotton Australia, QDO and QFF did not agree with the 10% floor for the carbon-exclusive price.

Canegrowers, supported by the QFF, suggested that prices for the irrigation tariffs 62, 65 and 66 should be reduced by 33%. They argued that the price rise proposed in the Draft Determination would result in consumers significantly reducing their usage, and that a price reduction of 33% would increase consumption to a level that is revenue neutral for the retailer.

Of the options identified in the Interim Consultation Paper for transitional pricing, Energex supported increasing prices to the level they would have been, had the QCA decision not been overruled, then calculating prices for 2014–15 using the same escalation method used for 2013-14. In contrast, EEQ, the Toowoomba Regional Council, the QFF, Canegrowers, Cotton Australia and the Queensland Government did not support making up the shortfall, on the basis that doing so would negate the benefit to businesses of the Government's decision to cap price increases. EnergyAustralia suggested that the price cap imposed by the Government in 2013-14 might require some adjustment to transitional arrangements, but not an extension of the seven-year transition period.

EEQ suggested that the QCA could engage with the distribution companies to obtain forecasts of network prices for the 2015–16 to 2019-20 regulatory period, in order to give an indication of likely price increases in future years.

AGL, Energex, EnergyAustralia and the ESAA disagreed with the QCA's 2013–14 decision to open access to transitional tariffs to all eligible customers. EnergyAustralia suggested transitional arrangements should only benefit customers for whom they were put in place and that access to new customers should therefore be closed. The ASMC, EEQ and the Queensland Government explicitly agreed that access should remain open for all eligible customers. Ergon Energy provided general support for the transitional arrangements put in place in 2013–14.

The ESAA did not support any of the transitional arrangements, on the basis that they distort the market and create financial risk for retailers. It suggested that assistance for rural and regional customers should be managed through Ergon Energy's distribution business.

How much to escalate transitional and obsolete tariffs

The Queensland Government's decision to cap price increases for transitional and obsolete tariffs in 2013–14 raises the question of whether future price increases should include a catch-up of more than 10% increases that customers were spared in 2013–14. If not, then customers will be left further below cost-reflective prices, and therefore face larger price increases when they are forced to move to cost-reflective tariffs at the end of the transition period.

However, the QCA considers that the intention of the Government's decision has relevance. The decision to cap price increases was a policy decision to further subsidise a segment of the market. As we have suggested previously, it would be more efficient to assist specific customer groups directly rather than by distorting electricity prices. Nevertheless, we recognise that it was the Government's intention to provide relief to customers on transitional and obsolete tariffs. On this basis, the QCA has decided not to include a catch-up of the more than 10% price increases customers avoided. This will benefit customers during the transition period and was supported in submissions. However, as noted above, it will mean that large price increases will be inevitable at the end of the period when cost-reflective prices are the only option.

We disagree with proposals for price reductions and no, or low (CPI), price increases in 2014–15 because these would result in customers' prices falling further below cost. In capping increases at 10% for 2013–14, the Queensland Government amended the Electricity Act so that it did not have to have regard to the costs of supply for these tariffs. However, this applied for 2013–14 only. As a result, we are bound by the same legislative requirements that applied for the 2013–14 Determination, which means we must have regard to the cost of supply in determining notified prices. These costs include those arising from AER-approved network prices, regardless of whether stakeholders feel they may fall in future years or may not be truly cost-reflective (as discussed in Chapter 2).

While it appears that recent price increases may partly explain lower-than-expected growth in total electricity use, we are not convinced that a 33% reduction in price will cause the increase in electricity use by irrigators claimed by Canegrowers. A key concern is that the analysis provided by Canegrowers does not appear to account for the level of rainfall and its relationship with electricity consumption for irrigation, which in many regions dictates the amount of pumping required each season. The Canegrowers Isis submission to the 2013–14 Draft Determination explicitly linked irrigation electricity use to seasonal conditions and explained that lower use in 2010–11 and 2011–12 was a result of them being "wet years". Further, the charts provided by Canegrowers show the beginning of the trend of falling consumption occurring over a number of years when price increases were at or near CPI, making it difficult to attribute increasing prices as the main factor in falling electricity use by customers on irrigation tariffs.

For these reasons, we maintain our view that the minimum first step for escalating transitional and obsolete tariffs should be an increase sufficient to reflect increases in the underlying costs of supply. This means 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 12 presents the increases in annual bills for typical customers on each of the cost-reflective tariffs, based on the draft prices for 2014–15. The consumption and demand data used in 2013–14 was provided by Energex and Ergon Energy and is used again this year for consistency. 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 12 Bill increases for cost-reflective tariffs in 2014–15[a]

Retail tariff	***Carbon-inclusive***	***Carbon-exclusive***
Energex network tariffs		
Tariff 20	11.5%	3.3%
Tariff 22[b]	12.2%	1.7%
Ergon Energy network tariffs		
Tariff 44	14.3%	2.8%
Tariff 45	13.5%	1.0%
Tariff 46	13.5%	-0.7%

a. Based on consumption data provided by Ergon Energy and Energex, presented in Appendix I.

b. Assumes 48%/52% peak/off-peak split, advised by Ergon Energy.

In keeping with the approach in the 2013–14 Determination, we have averaged the increases for tariffs 20 and 22, on the basis that the alignment of obsolete and transitional tariffs to tariffs 20 and 22 is not always clear cut, and the price impacts of moving to tariff 22 are sensitive to the assumed ratio of peak to off-peak consumption. The resulting average is an increase of 12%, which has been applied to the transitional and obsolete tariffs shown in Table 13. The average increase for tariffs 44, 45 and 46 is 14%, and is applied to transitional and obsolete tariffs that align with tariffs 44 to 48, as shown in Table 13.

Table 13 Alignment of cost-reflective and transitional and obsolete tariffs and underlying cost increases

Cost-reflective tariff	***Transitional or obsolete tariff***	***Escalation to reflect increase in underlying costs***	
		Carbon-inclusive	Carbon-exclusive
Tariff 20	Tariffs 21, 37, 66	12%	3%
Tariff 22	Tariffs 62, 65	12%	3%
Tariffs 44-48[a]	Tariffs 20 (large), 22 (small and large)[b], 41 (large), 43 (large)	14%	1%

a. The most appropriate of these tariffs depends on the customer's kW demand and voltage requirements.

b. Small customers on tariff 22 (small and large) will most likely move to the cost-reflective tariff 22, however as the bulk of customers on this tariff are large, it is aligned with the large customer tariffs for this purpose.

As discussed in the 2013–14 Determination, the escalation factors presented in Table 13 will maintain the gap to cost-reflectivity in percentage terms, but in dollar terms the gap will continue to grow. We have not changed our view that there should be an additional increase to limit how far below cost customers are in dollar terms. This will mitigate the ultimate transition to cost-reflective tariffs that customers will have to make and the cost to taxpayers of subsidising obsolete tariffs (noting that customers will face bigger price increases to cost-reflective tariffs as a result of the capping of 2013–14 price increases at 10%, as discussed above). More detailed discussion of the reasoning behind adding an additional escalation factor can be found in the 2013–14 Determination[49].

Analysis for 2013–14 of how far customers' prices are below cost revealed that the transitional and obsolete tariffs fall into three broad groups: one where a majority of customers' prices are 50% or more below cost (that is, they would experience price increases of 100% or more in moving to cost-reflective tariffs); one where a majority of customers' prices are between 50% and around 10% below cost (that is, they would experience increases of 10-100%); and one where a majority of customers' prices are less than around 10% below cost (that is, they would experience an increase of less than 10%). An analysis of updated data provided by Ergon Energy (presented in **Appendix D**) indicates that the same groupings are appropriate for 2014–15.

While cost-reflective prices are expected to increase less in 2014–15 than they did in 2013–14, the increases for carbon-inclusive prices are still reasonably significant. On this basis, we consider that price increases for customers on transitional and obsolete tariffs should be capped at the same upper limits included in our 2013–14 Determination, specifically:

- 1.5 times the underlying cost increases for customers whose prices are 50% or more below cost (that is, they would experience over 100% bill increases)
- 1.25 times underlying costs for customers whose prices are between 50% and around 10% below cost (that is, they would experience bill increases between 10% and 100%)
- 1.1 times underlying costs for customers whose prices are less than around 10% below cost (that is, they would experience bill impacts of less than 10%).

While Canegrowers disagreed with the use of escalation factors, on the basis that they are unrelated to underlying cost increases, we maintain that they are necessary as they are related to the actual underlying cost-reflective price.

However, if the carbon tax is repealed, underlying cost increases will be very low, between 1% and 3%, as shown in Table 13. As a result, applying the escalation factors outlined above will do very little to reduce how far customers' bills are below cost in dollar terms. We indicated in the 2013–14 Determination that these escalation factors may need to be higher in years of lower underlying cost increases, to prevent prices for transitional and obsolete tariffs and prices for cost-reflective tariffs drifting further apart in dollar terms.

Rather than adjusting the escalation factors, we have decided to use the simpler approach of implementing a floor to price increases of 10%. Specifically, prices for transitional and obsolete tariffs will be escalated by whichever is greater, 10% or the prices that result from applying the escalation factors indicated above. On this basis, we have set 2014–15 carbon-exclusive prices for all transitional and obsolete tariffs 10% higher than they were in 2013–14.

While some submissions disagreed with this proposal, we consider that a floor to price increases of 10% strikes a reasonable balance between protecting customers from even larger price increases and reducing the subsidy to these customers (which we estimate was roughly $110 million in 2012-13 and expect to be higher in 2013-14 as a result of the Government's 10% cap on price increases).

For example, if cost-reflective prices increase by only 5% after 2014-15, it would take annual increases of more than 20% in order to eliminate the subsidy received by the 11,000 customers whose prices are less than half-cost. Larger increases would be needed if cost-reflective prices

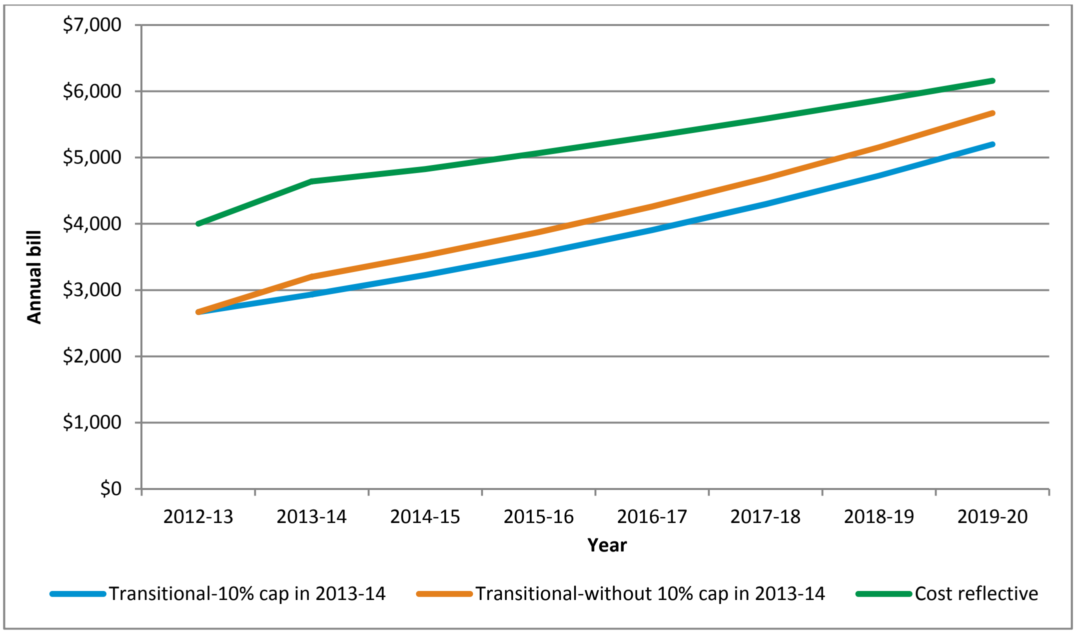
[49] QCA, *Final Determination: Regulated Retail Electricity Prices 2013-14*, May 2013, pp 92-93.

increase by more than 5%. With increases in transitional prices of only 10%, these customers would still face a significant price increase (of almost 60%) when they shift to a cost-reflective tariff at the end of the transition period.

There are more customers (around 18,000) whose prices are between 10% to 50% below cost. For customers in the mid-point of this group (i.e. whose prices are around a third below cost), annual price increases of 10% would still leave their prices well below cost-reflective prices at the end of the transition period, requiring a further price increase of almost 20% (assuming annual increases of 5% in cost-reflective prices) (see Figure 11). Again, larger increases would be needed if cost-reflective prices increase by more than 5% a year.

This figure also clearly demonstrates that customers benefit from the 10% cap placed on price increases in 2013-14 for the rest of the transition period. Had prices not been capped, transitional prices would have been only 8% below cost at the end of the transitional period.

Figure 11 - Hypothetical example, if the carbon tax is removed, of the impact of a 10% floor on transitional price increases on the gap to cost-reflective prices



Based on transitional tariffs aligned to cost-reflective tariffs 20 and 22, which include all irrigation and farming tariffs. Based on carbon-exclusive price increases for 2014-15 and assumed annual growth in cost-reflective prices of 5% thereafter.

Transition period

In the 2013–14 Determination, the QCA decided on a transition period of seven years for tariffs 20 (large), 21, 22 (small and large), 62, 65 and 66. The basis of this decision was to allow time for businesses to recoup some of the value of investments made to suit the level and structure of charges for obsolete and transitional tariffs. The majority of submissions that raised concerns about transitional and obsolete tariffs were from irrigators. As a result, the suggestion from Canegrowers, that the Australian Tax Office (ATO) defined depreciable life for an irrigation pump as 12 years, was used as a starting point for setting the transitional period. Some tariffs had been obsolete for a number of years, and most investments in this type of equipment would have been partly, if not fully, depreciated. Based on these factors, along with the desire to balance the transitioning with the cost to taxpayers of continuing to subsidise these tariffs, we settled on the shorter period of seven years as an appropriate transition period.

Tariffs 41 (large) and 43 (large) were retained for a period of two years, on the basis that a significant number of customers would be better off on an alternative cost-reflective tariff.

In the Draft Determination we proposed to retain the transitional periods established in the 2013–14 Determination. Setting these periods was intended to provide certainty to businesses so that they could prepare for the new tariffs. As a result, we do not think it is appropriate to create uncertainty by potentially changing the time period unless an analysis of customer impacts indicates that the tariff could be removed without significant customer detriment.

Analysis for 2014–15 does not support the removal of any tariffs in 2014–15 (see **Appendix D**). Specifically, a large number of customers on tariffs with seven-year transition periods would still experience significant price impacts if they moved to cost-reflective tariffs immediately.

While we have endeavoured to provide stakeholders with certainty in setting the transitional arrangements outlined in this chapter, it should be noted that other decisions may prevail. For example, the Queensland Government recently announced that it intends to end retail price regulation in south east Queensland on 1 July 2015, subject to certain conditions being met. It is unclear whether the Government intends to continue transitional arrangements for the 3,700 customers on transitional and obsolete tariffs in south east Queensland, should it decide to deregulate retail pricing in 2015. If no customers in south east Queensland have access to regulated tariffs, it is unlikely that retailers would continue to offer loss-making prices to those customers on transitional or obsolete tariffs.

Access to obsolete tariffs

The Delegation requires the QCA to consider whether customers on large business customer tariffs 44, 45, 46, 47, 48 should be able to access the transitional arrangements for transitional large business customer tariffs.

In the 2013–14 Determination, we decided that all business customers should have access to transitional tariffs throughout the seven-year transitional period, subject to individual tariff terms and conditions. This applied to tariffs 20 (large), 21, 22 (small and large), 62, 65, and 66. We made this decision to ensure equity for all businesses, but recognised that there could be an adverse impact on competition if retailers ended up supplying too many customers below cost.

The Queensland Government's decision to cap price increases for transitional tariffs at 10% could potentially exacerbate this issue. It is possible the price capping might incentivise more customers to access a transitional tariff than otherwise would have. While this might apply to only a small number of customers, continued capping of prices in future years may expand the pool of customers accessing subsidised prices.

While some stakeholders objected to the potential financial impact on retailers that is caused by allowing all customers access to transitional and obsolete tariffs, none of them indicated how significant this impact was and whether it was getting worse as a result of the Government's decision to cap 2013–14 price increases at 10%.

As a result, we have no new information to warrant changing our view that transitional tariffs should be open to new customers.

In order to monitor the potential impact on competition, we have obtained from retailers the number of customers they have on each of the transitional and obsolete tariffs and their load. This provides a basis for assessing whether the number of customers moving to transitional tariffs is causing material detriment to retailers over time. If there is a significant increase in the number of customers using transitional tariffs, and thereby increasing the subsidy paid by taxpayers, we will consider closing the tariffs to new customers. Over the first six months of 2013–14, there had not been a material increase in the number of customers on these tariffs.

Conclusion on transitional arrangements

A summary of the transitional arrangements we propose for 2014–15 is provided in Table 14. Tariffs available to new customers are referred to as transitional and tariffs not available to new customers are referred to as obsolete.

Table 14 Transitional arrangements for 2014–15

Obsolete/transitional tariff	***Period to be retained***	***Carbon-inclusive price increase***	***Carbon-exclusive price increase***
Tariff 21 – transitional	6 years	18.0%	10.0%
Tariff 37 – obsolete	6 years	15.0%	10.0%
Tariff 62 – transitional	6 years	15.0%	10.0%
Tariff 65 – transitional	6 years	15.0%	10.0%
Tariff 66 – transitional	6 years	15.0%	10.0%
Tariff 20 (large) – transitional	6 years	17.5%	10.0%
Tariff 22 (small and large) – transitional	6 years	17.5%	10.0%
Tariff 41 (large) – obsolete	1 year	15.4%	10.0%
Tariff 43 (large) – obsolete	1 year	15.4%	10.0%

7 FINAL DETERMINATION

This chapter sets out the QCA's Final Determination of regulated retail electricity prices (notified prices) to apply from 1 July 2014 to 30 June 2015, as well as expected customer impacts.

Under the network plus retail (N+R) approach, retail tariffs are aligned with network tariffs approved by the AER. For the purposes of this Final Determination, Energex and Ergon Energy have provided the 2014–15 network tariffs they intend to charge retailers during 2014-15. The network tariffs used to develop notified prices for 2014–15 are discussed in Chapter 2.

Chapters 3 and 4 set out the QCA's decisions on energy and retail costs which comprise the R component of the tariff calculation. A headroom allowance, discussed in Chapter 5, is applied to the total N+R cost build-up to arrive at the final retail tariffs.

The Final Determination also includes notified prices for nine retail tariffs that have been declared obsolete. Transitional arrangements for access to these tariffs are discussed in Chapter 6.

Due to uncertainty surrounding the future of the Commonwealth Government's carbon pricing mechanism, the QCA has calculated two sets of notified prices which reflect the underlying energy purchase costs with, and without, carbon pricing. As discussed in Chapter 3, the QCA will set notified prices to apply from 1 July 2014 that include the full impact of the carbon tax. If and when the carbon price legislation is repealed, the carbon-exclusive notified prices will be available to be applied. To implement these carbon-exclusive prices after the carbon tax is repealed, the Minister will need to make a new price determination, or direct the QCA to do so. Carbon-exclusive notified prices are set out in **Appendix G**.

The regulated retail tariffs and notified prices are published in a tariff schedule which includes other information, including the eligibility criteria and terms and conditions for each regulated retail tariff. The tariff schedule for 2014–15 is provided in **Appendix H**.

The following tables set out the QCA's Final Determination of regulated retail tariffs for 2014–15, inclusive of the impact of the carbon pricing mechanism. All tariffs are presented exclusive of GST.

Table 15 2014–15 Regulated retail tariffs and prices for residential customers (GST exclusive)

Retail tariff	*Energex network tariff*	*Fixed charge [a]*	*Variable rate (flat)*	*Variable*	*Variable*	*Variable*
				rate 1 (off-peak)	*rate 2 (shoulder)*	*rate 3 (peak)*
		c/day	*c/kWh*	*c/kWh*	*c/kWh*	*c/kWh*
Tariff 11 - Residential (flat rate)	8400	83.414	28.015			
Tariff 12 - Residential (time of use)	8900	116.609		20.094	23.590	33.583
Tariff 13 - Residential (PeakSmart)	7600	116.609		17.898	23.294	33.046
Tariff 31 - Night rate (super economy)	9000		14.375			
Tariff 33 - Controlled supply (economy)	9100		20.997			

a. Charged per metering point.

Table 16 2014–15 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*	*Variable rate*	*Variable rate*	*Variable rate*
			Charge	*(flat)*	*(off-peak)*	*(peak)*
		c/day	*$/kW/month*	*c/kWh*	*c/kWh*	*c/kWh*
Tariff 20 - Business (flat rate)	8500	140.437		26.222		
Tariff 22 - Business (time of use)	8800	140.437			21.555	28.236
Tariff 41 - Low voltage(demand)	8300	804.843	26.878	12.933		
Tariff 91 - Unmetered	9600			22.469		

a. Charged per metering point.

Table 17 2014–15 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	5,165.356	38.514	13.244
Tariff 45 - Over 100 MWh medium (demand)	EDMT1	16,807.334	34.556	13.244
Tariff 46 - Over 100 MWh large (demand)	EDLT1	48,836.212	33.113	13.244
Tariff 47 - High voltage (demand)	EDHT1	40,212.244	24.412	12.552
Tariff 48 – Over 4 GWh High voltage (demand)	EDHT1	40,629.628	24.412	12.552
Tariff 71 - Street lighting [b]	EVUT1	0.668		34.390

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

Table 18 2014–15 Transitional and obsolete regulated retail tariffs and prices (GST exclusive)

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]		26.283	18.717		46.815				
Transitional tariffs for small customers and Ergon Energy large customers									
Tariff 21		66.014	44.859	42.148	32.087				
Tariff 22	161.991		43.691		15.385				
Tariff 62	69.489		41.202	34.843	14.569				
Tariff 65	69.489		32.867		18.103				
Tariff 66	153.151					17.227		33.410	100.453
Obsolete Tariffs for large customers in Ergon Energy's network area									
Tariff 41(large)[a]	243.474					10.938	52.020		
Tariff 43(large)[a]	243.474		22.255		8.896		22.530		
Transitional Tariffs for large customers in Ergon Energy's network area									
Tariff 20(large)	67.403					32.971			

a. New customers are not eligible for these retail tariffs.
b. Charged per metering point.
c. Tariff 21 – first 100kWh, tariff 22 – 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, tariff 65 – 12hr peak.
d. Tariff 21 – 101-10,000kWh, tariff 62 – 7am-9pm M-F over 10,000kWh.
e. Tariff 21 – over 10,000 kWh, tariff 22 – all other times, tariff 37 – 4:30pm-10:30pm, tariffs 43 (large), 62, & 65 – all other times.

7.1 Underlying cost drivers

Cost-reflective notified prices will rise in 2014–15 due to increases in the underlying costs of supply. Most notably, the wholesale cost of energy, which reflects the price of electricity in the national generation market, is expected to increase by 21.5% compared to 2013–14, based on carbon inclusive estimates. This increase is expected to be driven by rising industrial demand associated with rapid development of the liquefied natural gas (LNG) export industry in Queensland and higher fuel prices (mainly gas).

The surge in wholesale energy costs is expected to be offset to some degree by modest decreases in other energy-related costs. These include the renewable energy target (RET) scheme costs and the costs of complying with the Queensland Gas Scheme, which was closed on 31 December 2013.

The second major cost driver is the Queensland Government's Solar Bonus Scheme. The scheme's costs have almost doubled since 2013-14 and will continue to push up prices in future years as distributors recoup costs incurred in paying feed-in tariffs to solar customers. The impact of the Solar Bonus Scheme on network tariffs is expected to peak in 2015–16, at which time about 34% of Energex's network prices will be due to the Solar Bonus Scheme.

Increases in network costs (excluding costs related to the Solar Bonus Scheme) are the third major cost driver. Network revenue allowances are approved by the AER. Network prices are also increasing because of lower than forecast consumption which means that network charges must increase to recover the allowed revenue.

Retail operating costs have also increased marginally from 2013–14, in line with inflation.

The impact of price increases on individual customers will vary depending on their retail tariff(s) and their consumption.

7.2 Customer impacts

Figures 12 and 13 show the percentage change that typical residential and business customers can expect in their annual electricity bills moving from 2013–14 to 2014–15. The estimated bill impacts are presented with and without the impact of the carbon tax.

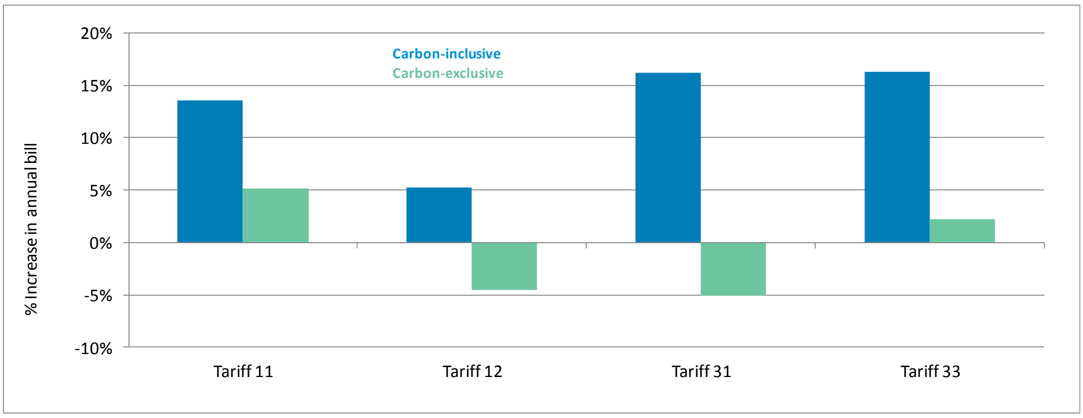
It is important to note that the changes shown in the figures are for levels and patterns of consumption that are typical of customers on regulated tariffs. Some customers may have consumption or household profiles that differ significantly from the levels assumed in this analysis and therefore may experience quite different impacts.

The potential repeal of the carbon tax could see 2014–15 annual bills decrease for a small number of customers compared to 2013–14. However, this would not be the case for most customers. For example, even without the carbon tax, typical customers on tariff 11 would still see an increase from 2013–14, albeit a smaller increase than would have occurred. Based on carbon-inclusive prices, a typical tariff 11 bill would increase by 13.6%, while in the absence of the carbon tax a typical tariff 11 bill would increase by 5.1%. This is due to the impact of higher network costs and the rebalancing of the fixed and variable retail tariff components, which would more than offset the decrease in tariffs due to removal of the carbon tax.

Residential customers

Figure 12 shows the percentage changes that typical residential customers can expect in their annual electricity bills from 2013–14 to 2014–15 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.

Figure 12 Changes in electricity bills in 2014–15 for residential customers [a]



a. Bill impacts are based on assumed annual consumption levels as set out in Appendix I.

Analysis of the transitional arrangements for customers on residential tariff 11 is provided in Chapter 6. Table 19 provides further scenarios to give a wider illustration of the impacts for different types of customers.

This table shows that the lower the customer's consumption, the higher the percentage increase in the customer's bill will be. 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 components towards a more cost-reflective pricing structure. The impacts for different types of customers, excluding a price on carbon, are shown in Table 20.

Table 19 Change in electricity bills in 2014–15 for tariff 11 customers (including carbon)

Customer Type[a]	*Annual consumption (kWh)*[b]	*2013–14 Annual Bill*	*2014–15 Annual Bill*	*Typical increase ($)*	*Typical increase (%)*
Mostly vacant holiday home	1,000	$495.79	$643.30	$147.51	29.8%
Frugal single person	2,200	$848.62	$1,013.10	$164.48	19.4%
Frugal couple; high-earner single person	3,070	$1,104.31	$1,281.08	$176.77	16.0%
Single parent one child; couple no children	4,091	$1,404.69	$1,595.90	$191.22	13.6%
Couple with one child; single parent two children;	5,112	$1,704.83	$1,910.48	$205.65	12.1%
Two parent, two child family	6,133	$2,004.97	$2,225.05	$220.08	11.0%
Two parents, two children, pool; two parents four children	8,490	$2,697.93	$2,951.33	$253.40	9.4%
Two parents, four children, pool; two parents six children	10,572	$3,310.21	$3,593.06	$282.85	8.5%

a. Tariff 11 customers will typically also have consumption on one of the off-peak tariffs (tariff 31 or 33)

b. Annual consumption thresholds were based on ACIL Tasman's 'Electricity Bill Benchmarks for Residential Customers', December 2011; and the Australian Energy Regulator's Energy Made Easy comparator, available at: http://www.energymadeeasy.gov.au/bill-benchmark

Table 20 Change in electricity bills in 2014–15 for tariff 11 customers (excluding carbon)

Customer Type[a]	*Annual consumption (kWh)*[b]	*2013–14 Annual Bill*	*2014–15 Annual Bill*	*Typical increase ($)*	*Typical increase (%)*
Mostly vacant holiday home	1,000	$495.79	$614.29	$118.50	23.9%
Frugal single person	2,200	$848.62	$949.28	$100.66	11.9%
Frugal couple; high-earner single person	3,070	$1,104.31	$1,192.04	$87.73	7.9%
Single parent one child; couple no children	4,091	$1,404.69	$1,477.23	$72.54	5.2%
Couple with one child; single parent two children;	5,112	$1,704.83	$1,762.19	$57.36	3.4%
Two parent, two child family	6,133	$2,004.97	$2,047.16	$42.19	2.1%
Two parents, two children, pool; two parents four children	8,490	$2,697.93	$2,705.08	$7.15	0.3%
Two parents, four children, pool; two parents six children	10,572	$3,310.21	$3,286.39	-$23.82	-0.7%

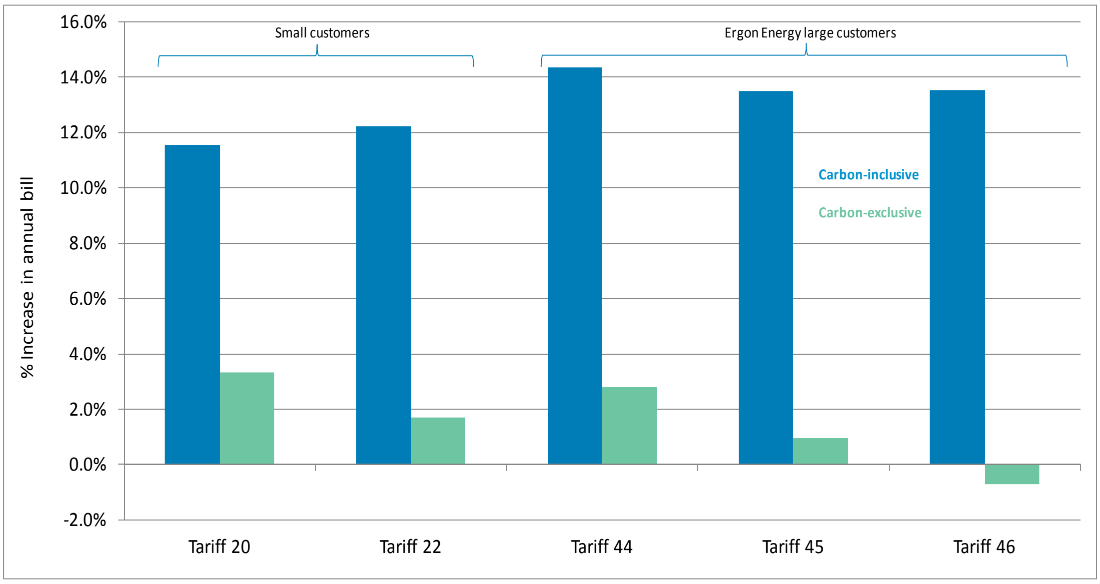
a. Tariff 11 customers will typically also have consumption on one of the off-peak tariffs (tariff 31 or 33)

b. Annual consumption thresholds were based on ACIL Tasman's 'Electricity Bill Benchmarks for Residential Customers', December 2011 and the Australian Energy Regulator's Energy Made Easy comparator, available at: http://www.energymadeeasy.gov.au/bill-benchmark

Non-residential and business customers

Figure 13 presents the expected increases in annual bills for typical business customers from 2013–14 to 2014–15. Bill impacts will vary depending on each individual customer's level and pattern of consumption.

Figure 13 Change in electricity bills in 2014–15 for business customers [a]



a. Bill impacts are based on assumed annual consumption levels as set out in Appendix I.

Transitional arrangements for customers on obsolete tariffs

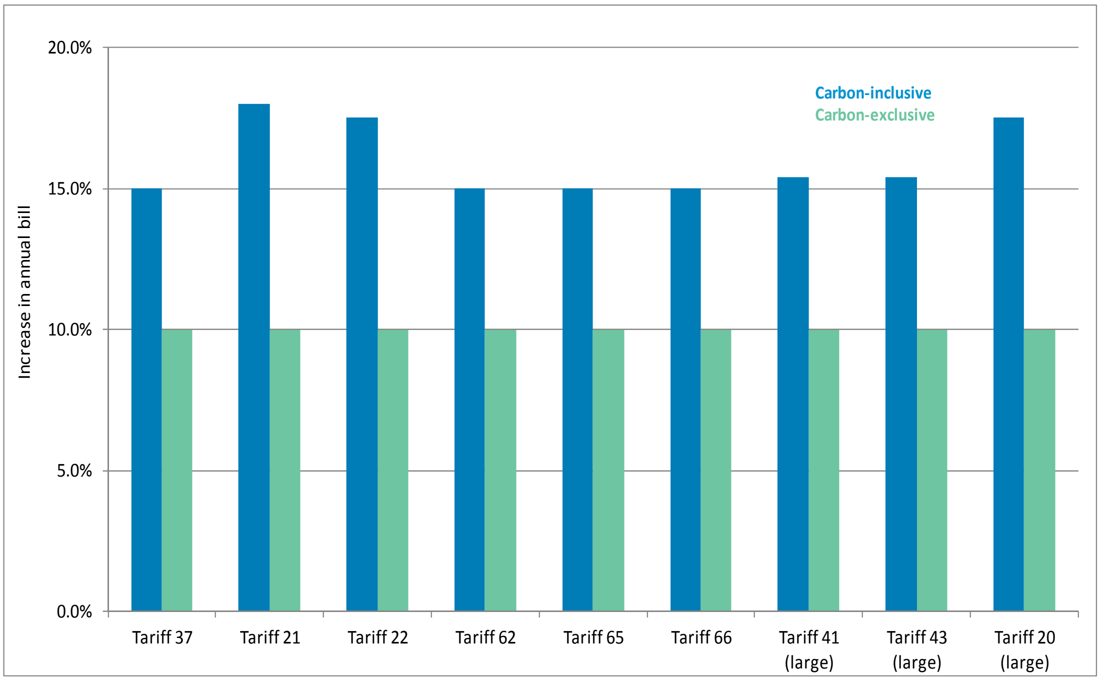
In 2013–14, the QCA established transitional arrangements for customers on most of the existing obsolete tariffs as many customers would have faced significant price impacts if they were immediately moved to a cost-reflective tariff.

The QCA has maintained these transitional arrangements for 2014–15. Based on carbon-inclusive prices, the bill increases for these tariffs are between 15% and 18%. 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 that the gap, in percentage terms, between the obsolete and cost-reflective tariff does not grow.

If carbon-exclusive prices are used, the percentage increases in 2014–15 would be small, which would do very little to reduce how far customers' bills are below cost in dollar terms. To prevent this, the QCA has set a floor to price increases of 10%. This is consistent with our statement in the 2013–14 Determination that in future years we may increase transitional tariffs by more than the underlying cost drivers if the cost drivers in that year were low.

New customers will be allowed to access the retained obsolete tariffs (to be referred to as transitional tariffs), 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. Figure 14 summarises the QCA's Final Determination on transitional arrangements for obsolete tariffs.

Figure 14 Change in electricity bills in 2014–15 for customers on transitional tariffs



GLOSSARY

A	
ACIL	ACIL Allen
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AFMA	Australian Financial Markets Association
ASMC	Australian Sugar Milling Council
ATO	Australian Taxation Office
B	
BRCI	Benchmark retail cost index
C	
CARC	Customer acquisition and retention costs
CER	Clean Energy Regulator
CPI	Consumer price index
CSO	Community service obligation
E	
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
ESAA	Energy Supply Association of Australia
ESCOSA	Essential Services Commission of South Australia
F	
Frontier	Frontier Economics
G	
GWh	Gigawatt hour
I	
ICRC	Independent Competition and Regulatory Commission
IDC	Interdepartmental Committee on Electricity Sector Reform
IPART	Independent Pricing and Regulatory Tribunal
K	
kWh	Kilowatt hour

L	
LRMC	Long-run marginal cost
M	
Minister	Minister for Energy and Water Supply
MWh	Megawatt hour
N	
N	Network cost
NEM	National Electricity Market
NER	National Electricity Rules
NSLP	Net system load profile
NSW	New South Wales
O	
OTTER	Office of the Tasmanian Economic Regulator
P	
PV Water	Pioneer Valley Water
Q	
QCA	Queensland Competition Authority
QCOSS	Queensland Council of Social Service
QDO	Queensland Dairyfarmers' Organisation
QFF	Queensland Farmers' Federation
R	
R	Energy and retail cost
RET	Renewable energy target
ROC	Retail operating cost
RPP	Renewable Power Percentage
S	
SBS	Solar Bonus Scheme
SRES	Small-scale renewable energy scheme
STC	Small-scale technology certificate
STP	Small-scale technology percentage
T	
TFS	Tradition Financial Services
TUOS	Transmission use of system
U	
UTP	Uniform tariff policy

APPENDIX A: MINISTERIAL DELEGATION AND COVER LETTER

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

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.

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)

APPENDIX B: SUBMISSIONS

Submissions to the Interim Consultation Paper

Organisation/individual

1. AGL
2. AGL supplementary submission
3. Alinta Energy
4. Canegrowers
5. Canegrowers Isis
6. Clean Energy Council
7. Cotton Australia
8. Energex Ltd
9. EnergyAustralia
10. Energy Supply Association of Australia
11. Energy Retailers Association of Australia
12. Ergon Energy Corporation Ltd
13. Ergon Energy Queensland Pty Ltd
14. Ergon Energy Queensland Pty Ltd supplementary submission
15. ERM Power Ltd
16. Lumo Energy
17. Origin Energy
18. Origin Energy supplementary submission
19. Pioneer Valley Water Co-operative Ltd
20. QEnergy
21. Queensland Consumers' Association
22. Queensland Council of Social Services
23. Queensland Farmers' Federation
24. Queensland Government
25. Toowoomba Regional Council

Submissions to the Draft Determination

Organisation/individual

1. AGL
2. Alinta Energy

3. Allan, C. & S.
4. Australians in Retirement, Cairns and District Branch
5. Australian Sugar Milling Council
6. Burnett, R.
7. Canegrowers
8. Canegrowers Isis
9. COTA Australia
10. Cotton Australia
11. Energex Ltd
12. EnergyAustralia
13. Energy Retailers Association of Australia
14. Energy Retailers Association of Australia supplementary submission
15. Energy Supply Association of Australia
16. Ergon Energy Corporation Ltd
17. Ergon Energy Queensland Pty Ltd
18. Jessop, J.
19. Laurie, K.
20. Local Government Association of Australia
21. Lumo Energy
22. Miller, R.
23. Miller, W.
24. Name withheld
25. Origin Energy
26. Pioneer Valley Water Co-operative Ltd
27. Queensland Consumers’ Association
28. Queensland Council of Social Services
29. Queensland Dairyfarmers' Organisation
30. Queensland Farmers’ Federation
31. The Solar Guys
32. Tonkin, C.
33. Confidential submission

APPENDIX C: SUMMARY OF CONCESSIONAL ARRANGEMENTS FOR ENERGY IN QUEENSLAND

Concession Name	*Eligibility Criteria*	*Annual Amount*[1]
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.	$282.54
Reticulated Natural Gas Rebate	As for Electricity Rebate.	$65.58
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.	$282.54
Home Energy Emergency Assistance Scheme	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 two consecutive 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.	Up to $575.44 per year for each oxygen concentrator; Up to $385.36 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, and is reimbursed for non-market customers of other retail entities.

1 GST inclusive.

2 Information provided is a guide only. Full details are available from: http://www.dews.qld.gov.au/energy-water-home/electricity/rebates and https://www.ergon.com.au/your-home/electricity-prices/drought-relief

APPENDIX D: ERGON ENERGY CUSTOMER IMPACTS

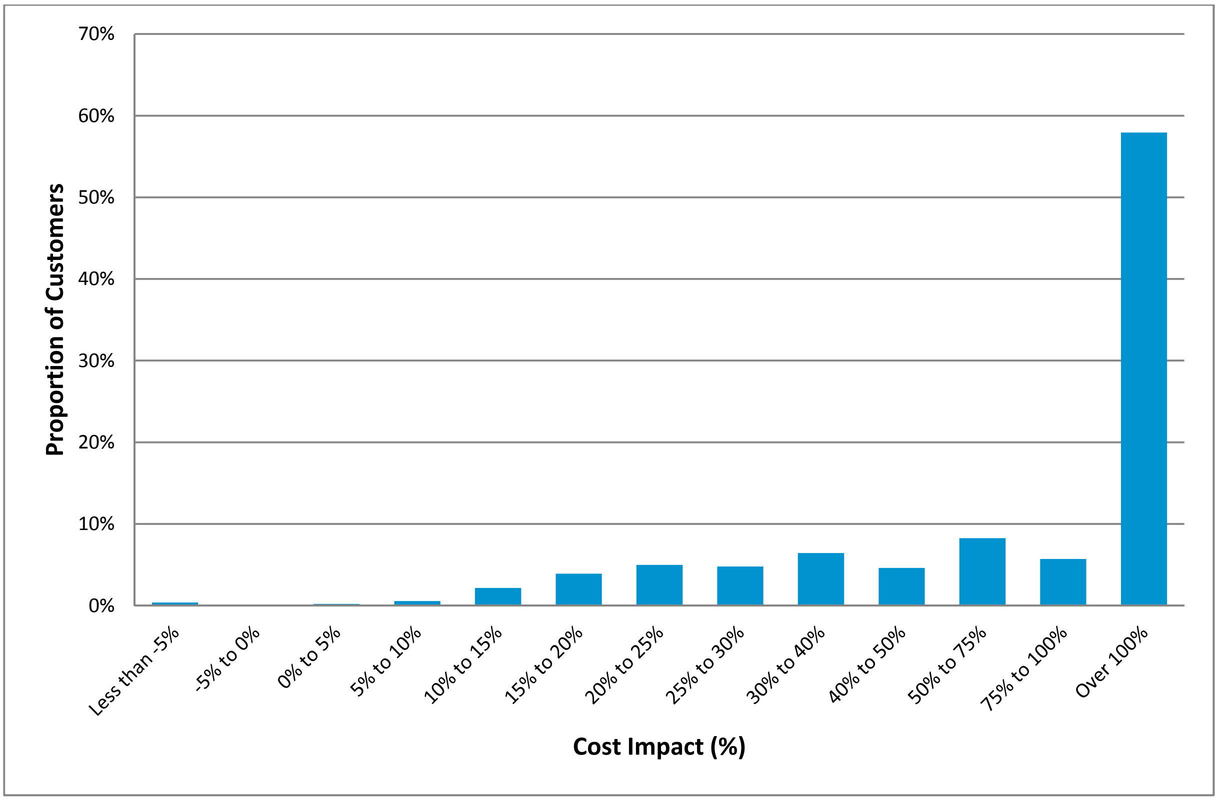
This appendix contains the analysis of bill impacts for customers on transitional and obsolete tariffs discussed in section 6.4.

Information provided by Ergon Energy is based on customers moving from their obsolete or transitional 2013–14 tariffs to cost-reflective 2014–15 tariffs. The impacts will therefore be larger than indicated in the Draft Determination which, due to time constraints, only showed price impacts of moving to 2013-14 cost-reflective prices. Ergon Energy indicated that some customers are supplied under multiple tariffs and that the impacts of price changes in these tariffs are aggregated for each customer. Where customers are on multiple tariffs, they have been grouped according to the tariff on which they consume most of their electricity.

Tariffs 21, 37 and 66

Tariffs 21, 37 and 66 align with the cost-reflective tariff 20 for small customers, and large business tariffs 44 to 48 (depending on the customer's demand and voltage requirements) for large customers. Figures 15 to 19 show the impacts of customers moving to these cost-reflective tariffs.

Figure 15 Change in electricity bills for small customers on tariff 21 moving to tariff 20



- Tariff 21 is a transitional tariff for general business supply and is used by many thousands of customers.
- Use of tariff 21 is characterised by very low levels of consumption.
- The majority of customers would experience a bill impact of over 100%, although dollar impacts are relatively low.

- Due to the high number of customers and significant percentage impacts, tariff 21 will be retained for another six years and the charges will be 18% higher than in 2013-14 if the carbon tax remains (1.5 times the underlying cost increase) and 10% higher than in 2013–14 if the carbon tax is repealed (being the greater of a 10% increase or 1.5 times the underlying cost increase).

Figure 16 Change in electricity bills for small customers on tariff 37 moving to tariff 20

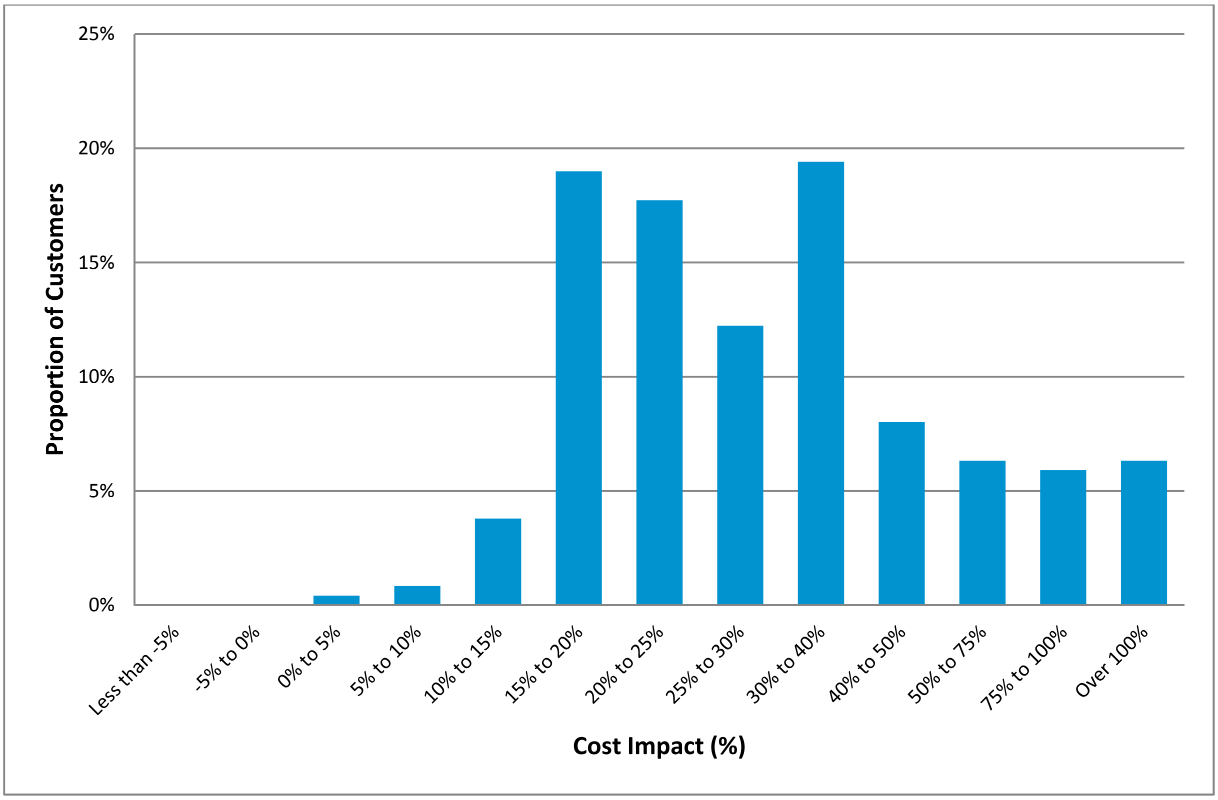
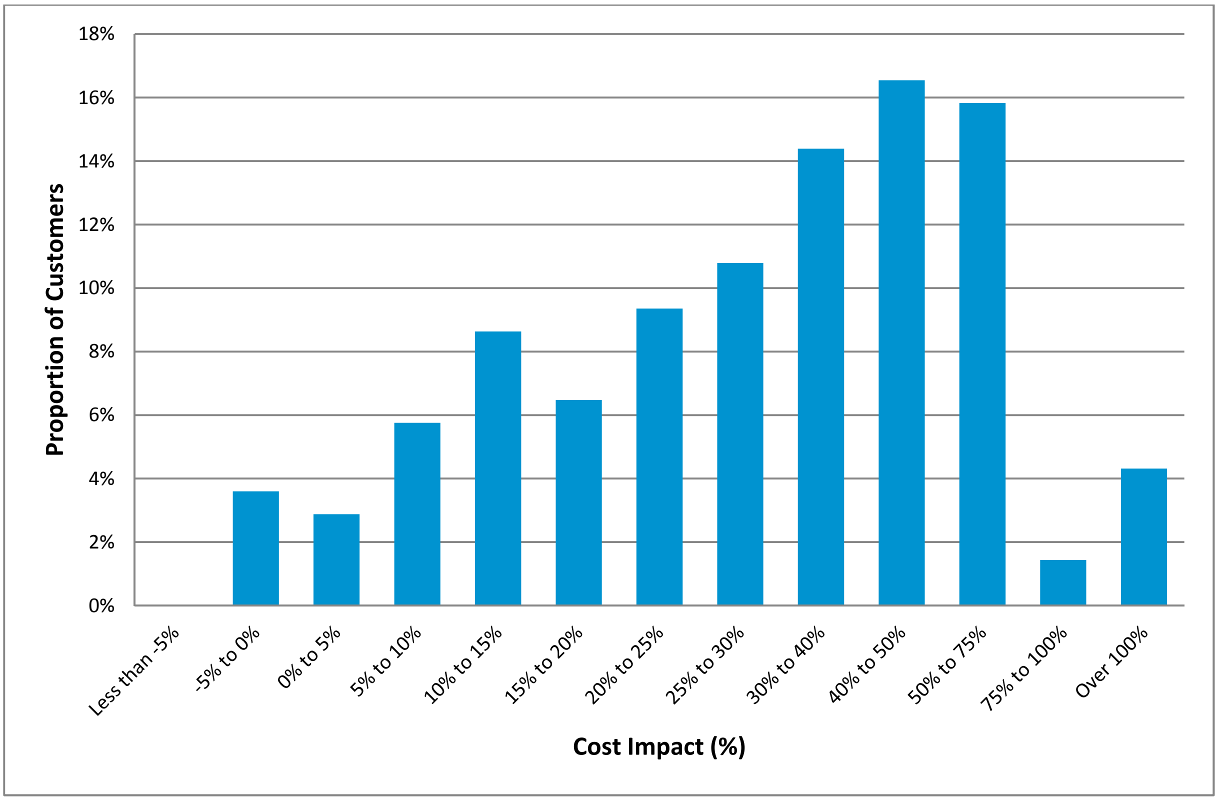


Figure 17 Change in electricity bills for large customers on tariff 37 moving to a large business tariff



An assumed demand profile has been used where demand data is unavailable. As a result, cost impacts may be over- or under-stated.

- Tariff 37 is for non-domestic heating loads and has been obsolete since 2007-08.
- There are a few hundred customers on this tariff.
- Ergon Energy indicated that the metering required to measure demand for large customers who would move to demand-based charges on tariffs 44-48 would not be in place for 2014–15.
- The majority of customers would experience a bill increase of 10%-100%, mainly 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.
- Due to price impacts and metering constraints, tariff 37 will be retained for another six years and the charges will be 15% higher than in 2013–14 if the carbon tax remains (1.25 times the underlying cost increase) and 10% higher than in 2013–14 if the carbon tax is repealed (being the greater of a 10% increase or 1.25 times the underlying cost increase).

Figure 18 Change in electricity bills for small customers on tariff 66 moving to tariff 20

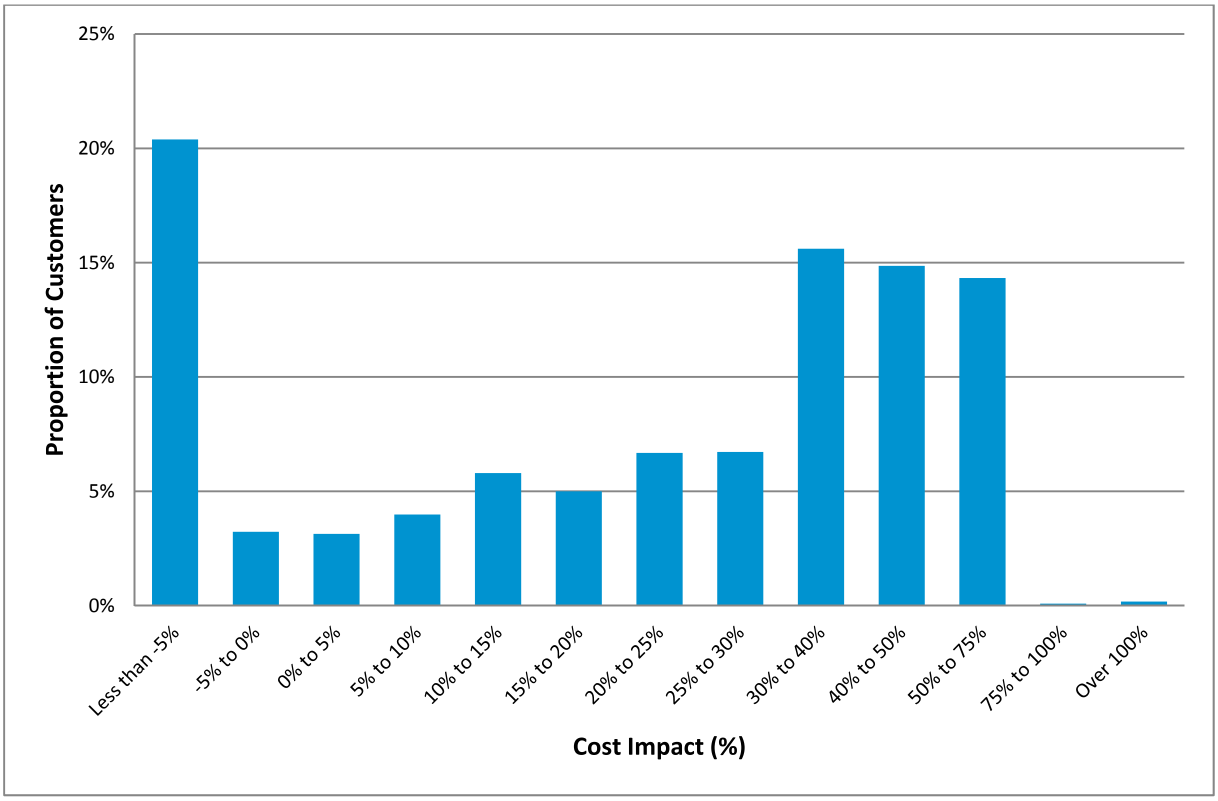
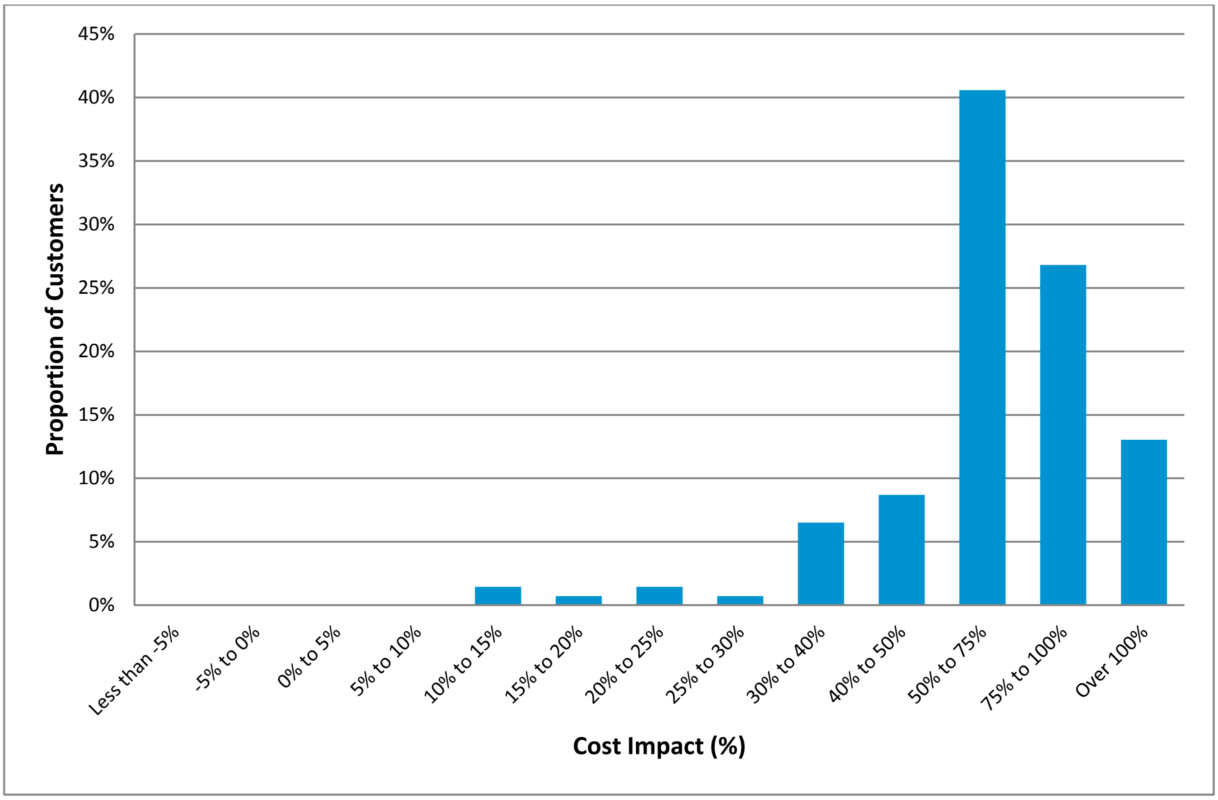


Figure 19 Change in electricity bills for large customers on tariff 66 moving to a large business tariff



An assumed demand profile has been used where demand data is unavailable. As a result, cost impacts may be over- or under-stated.

- Tariff 66 is a flat irrigation tariff used by a few thousand customers.
- Of the small customers 24% would be better off on tariff 20 due to a lower daily charge and the absence of a capacity charge for tariff 20, however some customers would experience large bill increases, due to the higher variable charge.
- Bill impacts are generally higher for large customers because tariff 66 does not include demand charges, which are included in the cost-reflective large business tariffs.
- Ergon Energy indicated that the metering required to measure demand for large customers who would move to demand-based charges on tariffs 44 to 48 would not be in place for 2014–15
- The majority of customers would experience increases between 10%-100%.
- Due to price impacts and metering constraints, tariff 66 will be retained for another six years and the charges will be 15% higher than in 2013–14 if the carbon tax remains (1.25 times the underlying cost increase) and 10% higher than in 2013–14 if the carbon tax is repealed (being the greater of a 10% increase or 1.25 times the underlying cost increase).

Tariffs 62 and 65

The majority of small customers on tariffs 62 and 65 will move to the cost-reflective tariff 22, and large customers will move to large business tariffs 44-48 (depending on demand and voltage requirements). Figures 20 to 23 show the impacts of customers moving to these cost-reflective tariffs.

Figure 20 Change in electricity bills for small customers on tariff 62 moving to tariff 22

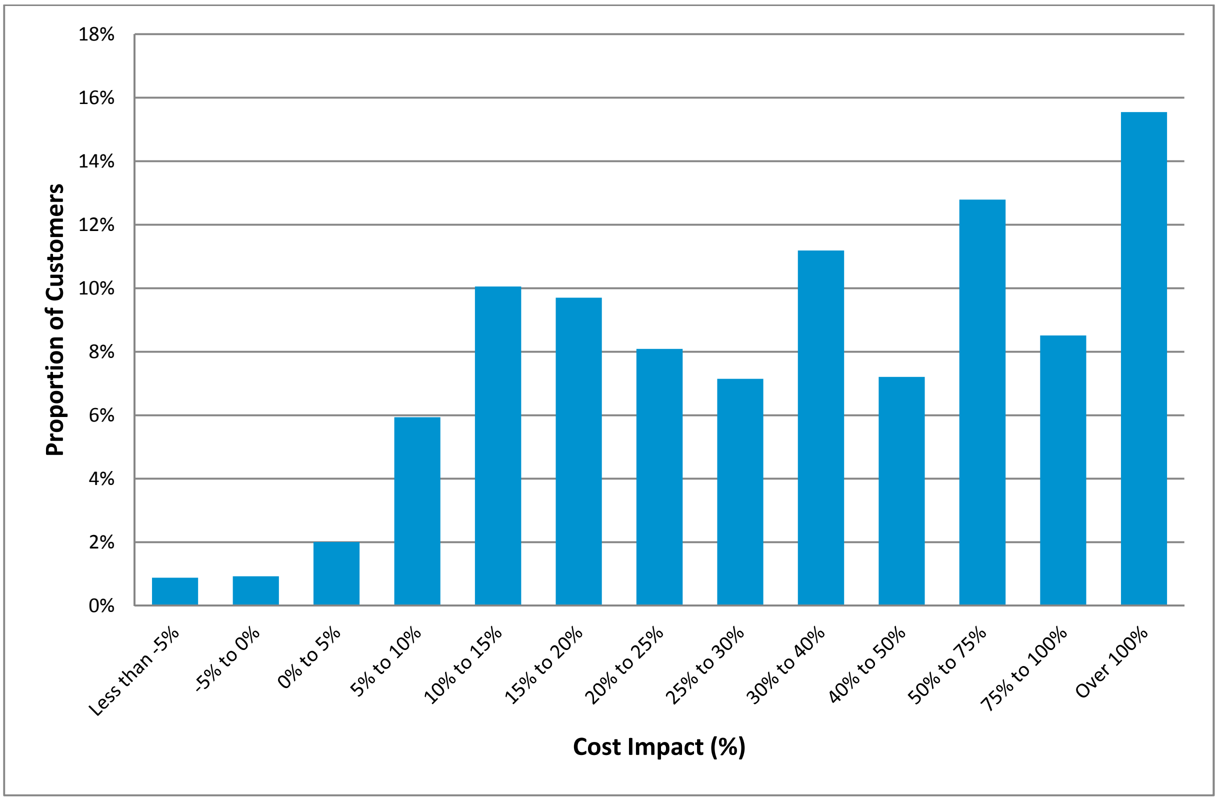
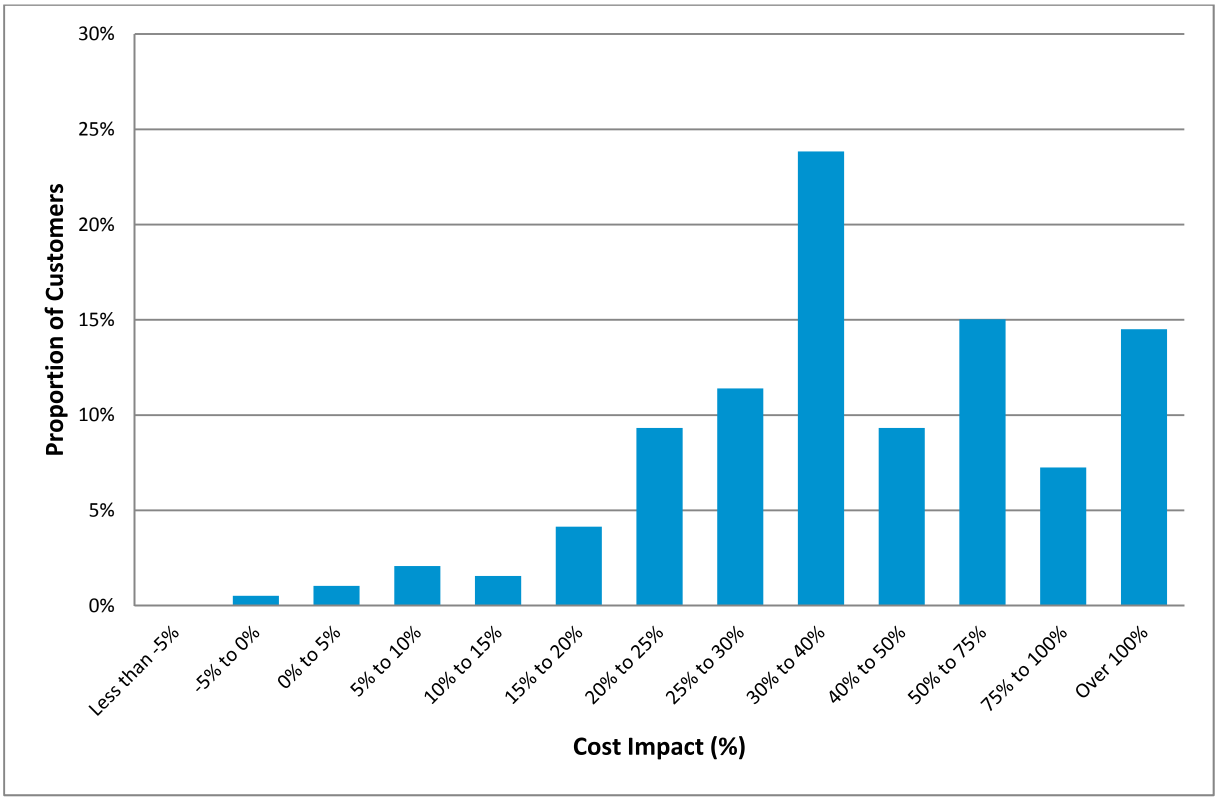


Figure 21 Change in electricity bills for large customers on tariff 62 moving to a large business tariff



An assumed demand profile has been used where demand data is unavailable. As a result, cost impacts may be over- or under-stated.

- Tariff 62 is a time-of-use farming tariff used by many thousands of customers.
- There are a wide range of impacts, mostly increases due to a higher off-peak rate on cost-reflective tariff 22 (for small customers) and moving to a demand-based tariff (for large customers).
- The majority of increases are between 10%-100%.
- Due to the high number of customers and significant percentage impacts, tariff 62 will be retained for another six years and the charges will be 15% higher than in 2013–14 if the carbon tax remains (1.25 times the underlying cost increase) and 10% higher than in 2013–14 if the carbon tax is repealed (being the greater of a 10% increase or 1.25 times the underlying cost increase).

Figure 22 Change in electricity bills for small customers on tariff 65 moving to tariff 22

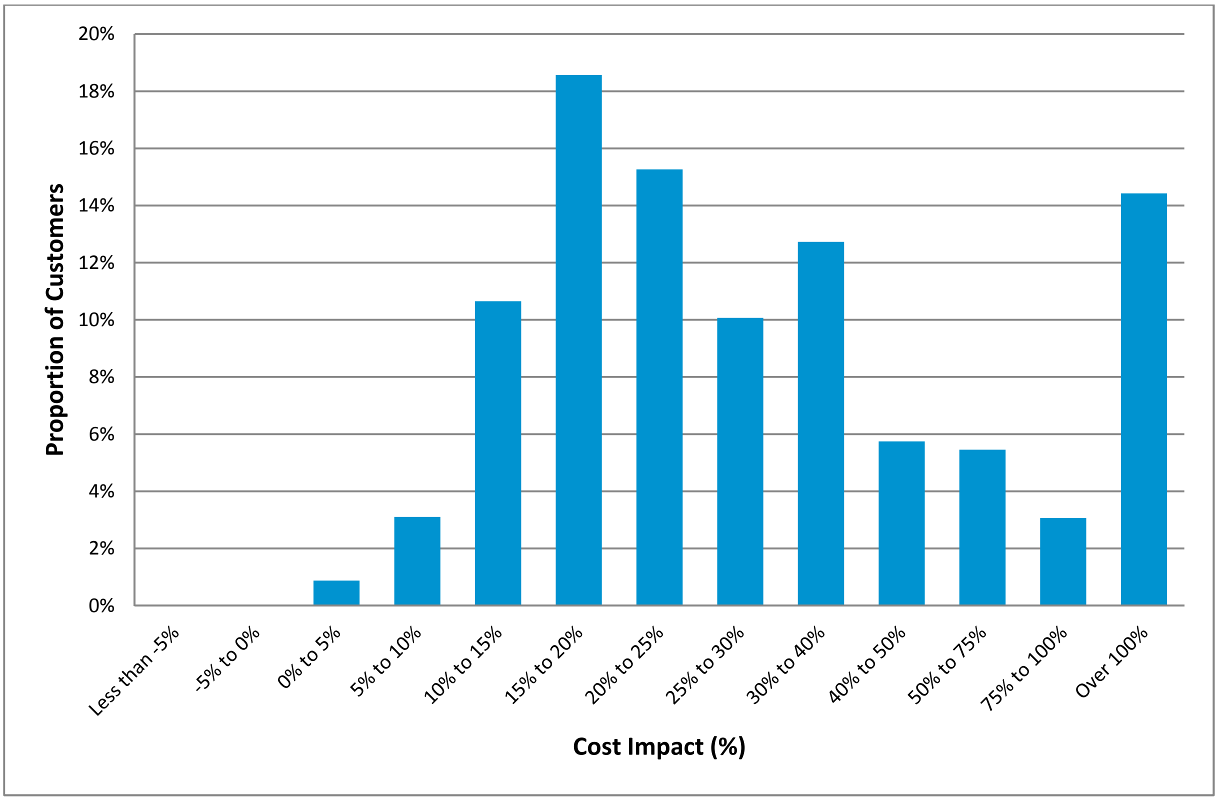
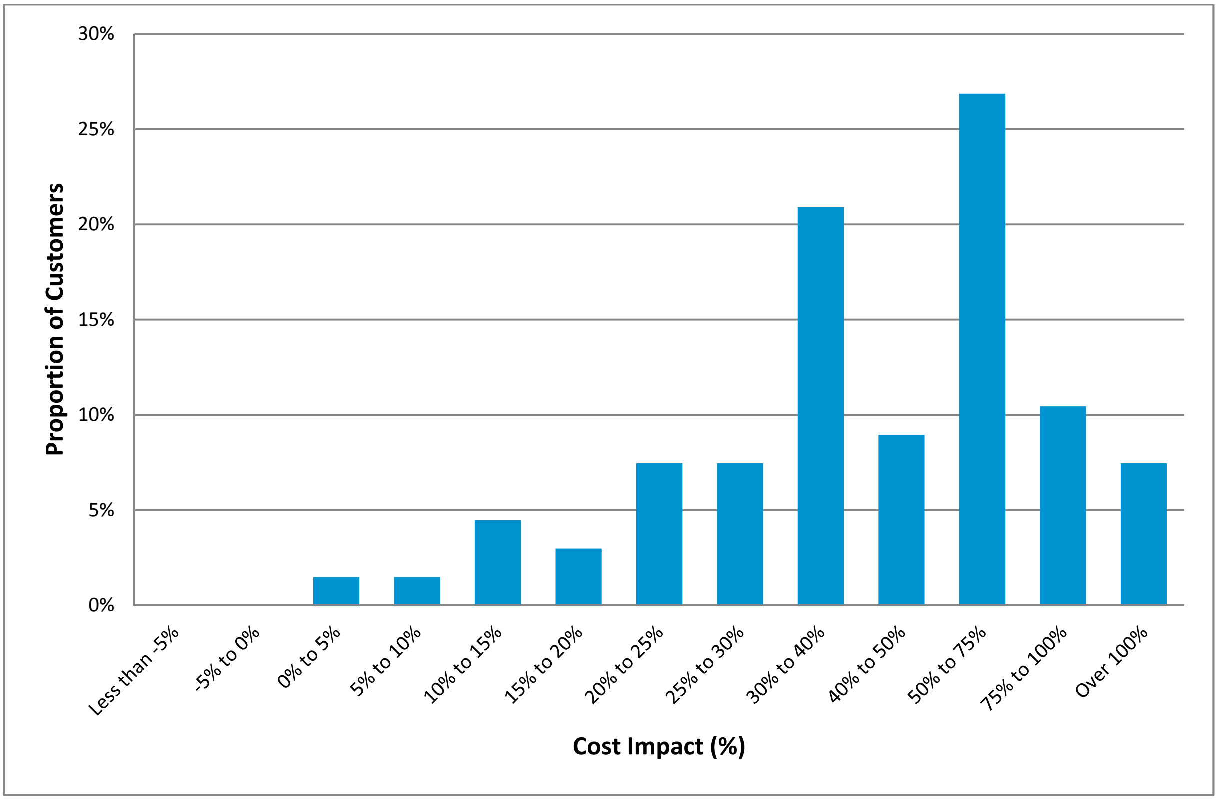


Figure 23 Change in electricity bills for large customers on tariff 65 moving to a large business tariff



An assumed demand profile has been used where demand data is unavailable. As a result, cost impacts may be over- or under-stated.

- Tariff 65 is a time-of-use irrigation tariff used by many thousands of customers.
- There are a wide range of impacts, mostly increases, due to a higher off-peak rate on cost-reflective tariff 22 for small customers, and demand-based charges in tariffs for large customers.
- The majority of increases are between 10%-100%.
- Due to the high number of customers and significant percentage impacts, tariff 65 will be retained for another six years and the charges will be 15% higher than in 2013–14 if the carbon tax remains (1.25 times the underlying cost increase) and 10% higher than in 2013–14 if the carbon tax is repealed (being the greater of a 10% increase or 1.25 times the underlying cost increase).

Large customer tariffs

Transitional large tariffs 20, 22, 41 and 43 align with cost-reflective tariffs 44 to 48, which are based on Ergon Energy network tariffs. Figures 24 to 27 show the likely impacts for customers moving from these transitional or 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 under-estimation of bill impacts, due to the sensitivity of bills to changes in maximum demand.

Figure 24 Change in electricity bills for customers on tariff 20 (large) moving to a large business tariff

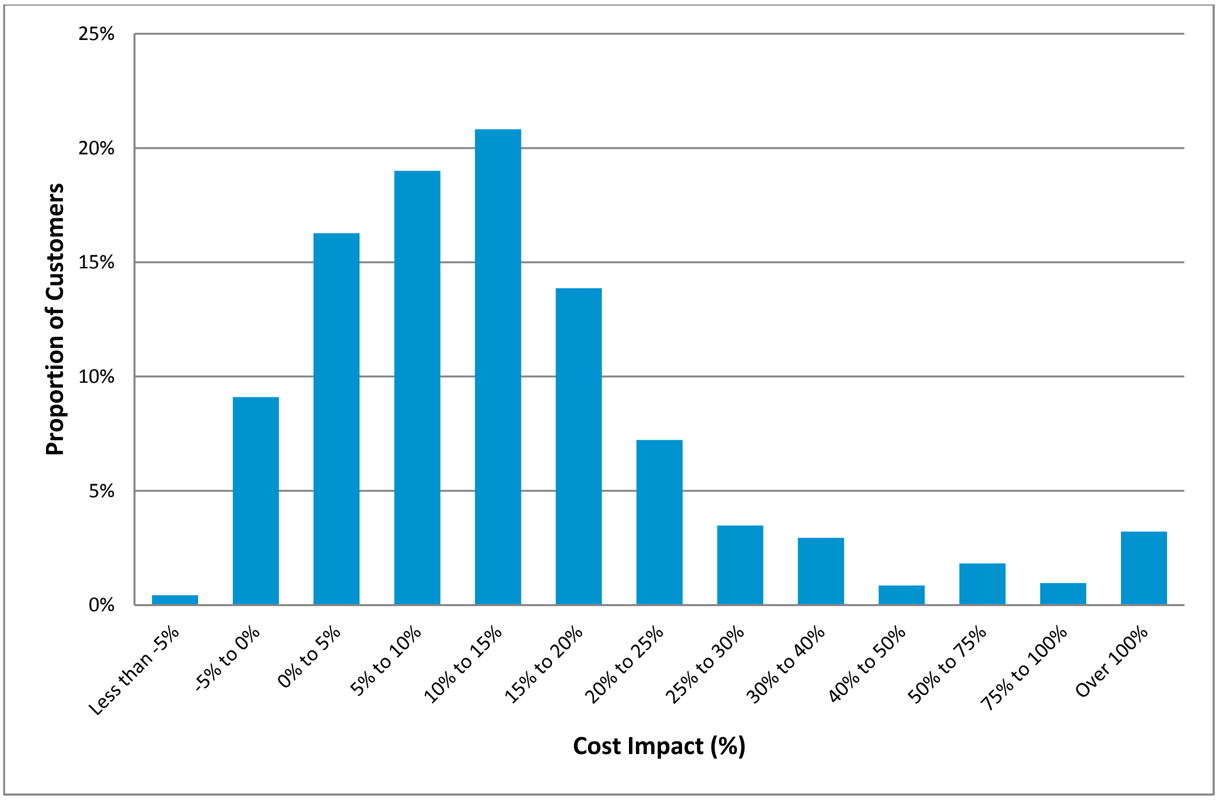
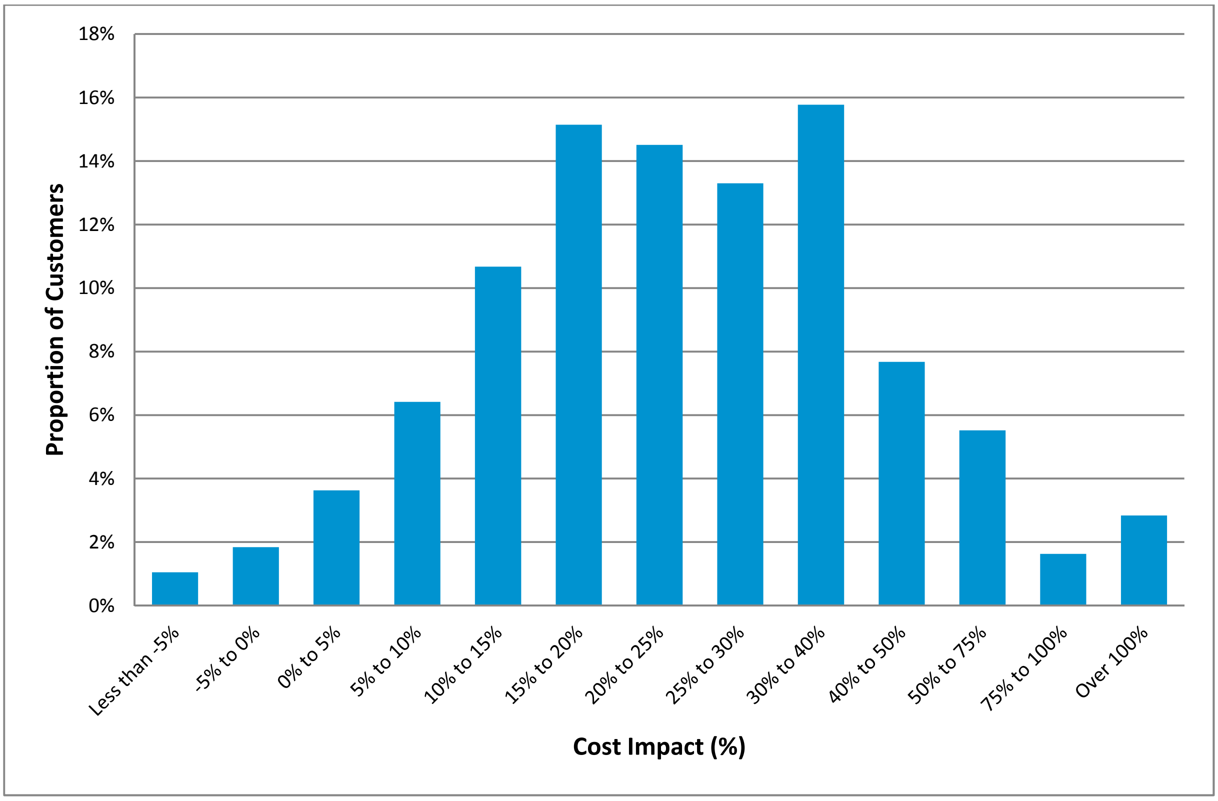


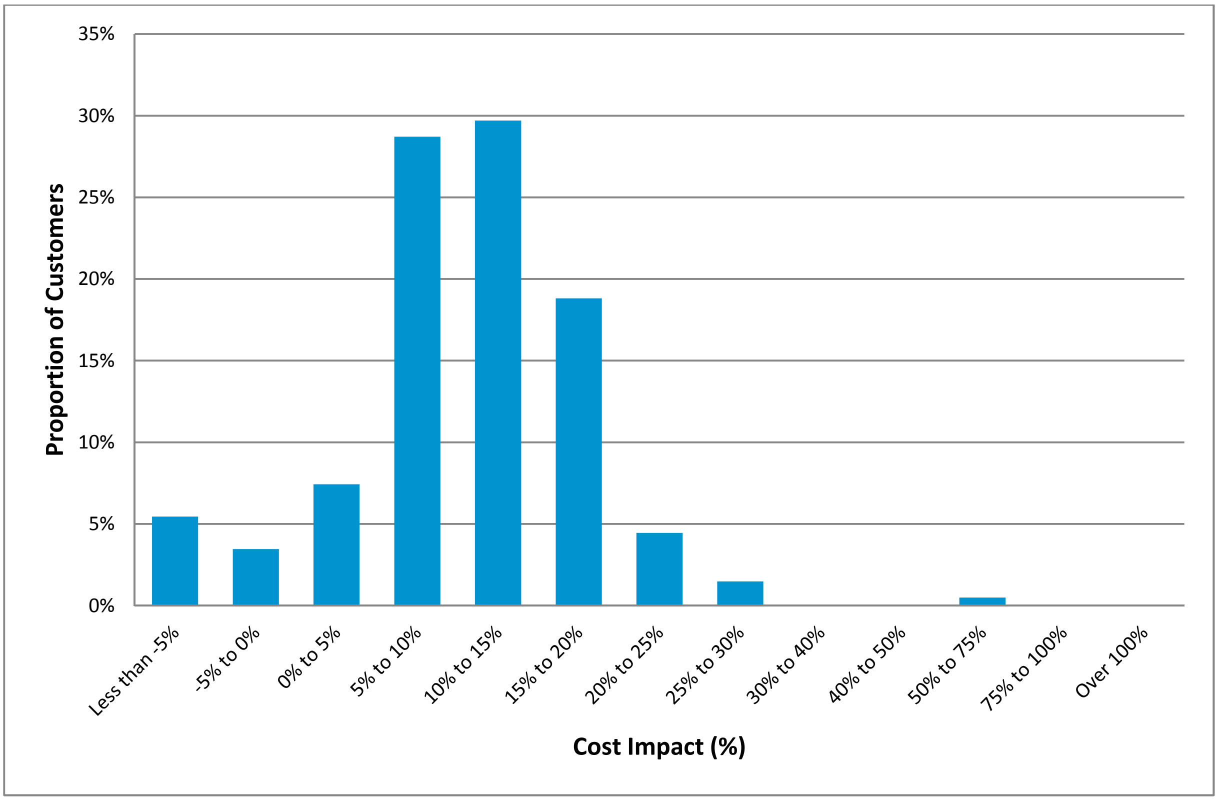
Figure 25 Change in electricity bills for customers on tariff 22 (large) moving to a large business tariff



An assumed demand profile has been used where demand data is unavailable. As a result, cost impacts may be over- or under-stated.

- Tariffs 20 and 22 are for large business customers. In 2013–14, tariff 22 was made available to small customers, although the bulk of customers on transitional tariff 22 are large.
- A few thousand customers are using these tariffs.
- The majority of customers on tariffs 20 and 22 would experience impacts of between 10% and 100%, mainly due to higher fixed charges and demand-based charges on the cost-reflective tariffs 44-48.
- Ergon Energy indicated that the metering required to measure demand for large customers who would move to demand-based charges on tariffs 44-48 would not be in place for 2014–15.
- Based on the number of customers, the level of impacts and metering constraints, tariffs 20 (large) and 22 (small and large) will be retained for another six years and charges will be 17.5% higher than in 2013–14 (1.25 times the underlying increase). If the carbon tax is repealed, prices for both will be 10% higher than in 2013–14 (being the greater of a 10% increase and their respective underlying cost increases).

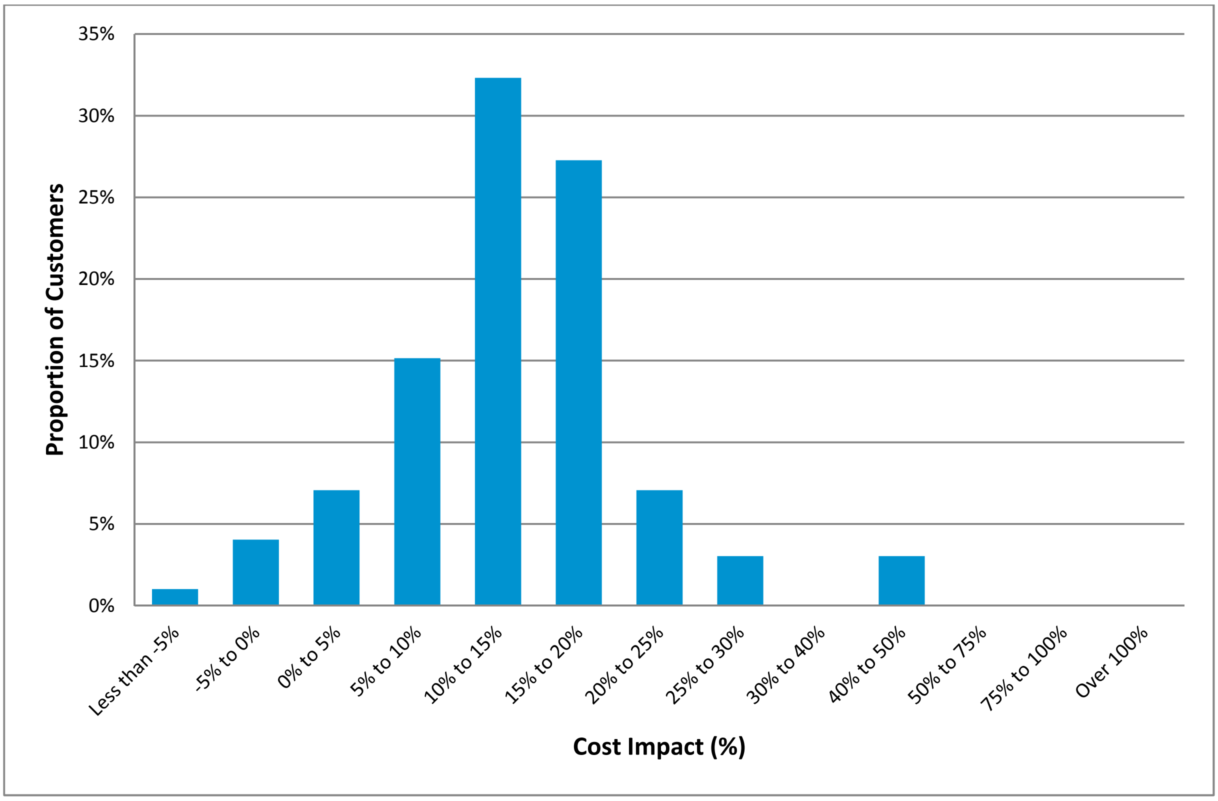
Figure 26 Change in electricity bills for customers on tariff 41 (large) moving to a large business tariff



An assumed demand profile has been used where demand data is unavailable. As a result, cost impacts may be over- or under-stated.

- Tariff 41 is a large-business, low-voltage general supply demand tariff used by a few hundred customers.
- The majority of customers would experience moderate impacts of up to 20% because customers are already facing a higher demand charge on tariff 41, which in many cases offsets the lower variable charge.
- Tariff 41 (large) will be retained for 2014–15 only, and the charges will be 15.4% higher than in 2013-14 if the carbon tax remains (1.1 times the underlying cost increase) and 10% higher than in 2013–14 if the carbon tax is repealed (being the greater of a 10% increase or 1.1 times the underlying cost increase). While the majority of increases falling between 10% and 100% would indicate using a multiple of 1.25, we have applied a multiple of 1.1 as most increases are close to 10%. This is consistent with the approach undertaken in the 2013–14 Determination.

Figure 27 Change in electricity bills for customers on tariff 43 (large) moving to a large business tariff



An assumed demand profile has been used where demand data is unavailable. As a result, cost impacts may be over- or under-stated.

- Tariff 43 is a large-business demand time-of-use tariff used by over a hundred customers.
- The majority of customers would experience moderate increases of up to 20%. The impacts of moving to a cost-reflective tariff are limited as customers already face a demand charge on tariff 43.
- Tariff 43 (large) will be retained for 2014–15 only and the charges will be 15.4% higher than in 2013-14 if the carbon tax remains (1.1 times the underlying cost increase) and 10% higher than in 2013–14 if the carbon tax is repealed (being the greater of a 10% increase or 1.1 times the underlying cost increase). While the majority of increases falling between 10% and 100% would indicate using a multiple of 1.25, we have applied a multiple of 1.1 as most increases are close to 10%. This is consistent with the approach undertaken in the 2013–14 Determination.

APPENDIX E: BUILD-UP OF CARBON-INCLUSIVE PRICES

Table 21 Residential regulated retail tariffs (GST exclusive) — carbon-inclusive

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)[c]	Network	59.100	12.640			
	Energy		10.082			
	SRES Cost Pass Through		0.036			
	Retail	45.626				
	Margin	6.330	1.376			
	Headroom	5.553	1.207			
	Total[b]	116.609	25.341			
Transitional Tariff 11[d]	Total[b]	83.414	28.015			
Tariff 12 - Residential (time of use)	Network	59.100		7.928	11.068	20.042
	Energy			10.082	10.082	10.082
	SRES Cost Pass Through			0.036	0.036	0.036
	Retail	45.626				
	Margin	6.330		1.091	1.281	1.823
	Headroom	5.553		0.957	1.123	1.599
	Total[b]	116.609		20.094	23.590	33.583
Tariff 13 - Residential (PeakSmart)	Network	59.100		5.956	10.802	19.560
	Energy			10.082	10.082	10.082
	SRES Cost Pass Through			0.036	0.036	0.036
	Retail	45.626				
	Margin	6.330		0.972	1.265	1.794
	Headroom	5.553		0.852	1.109	1.574
	Total[b]	116.609		17.898	23.294	33.046
Tariff 31 - Night rate (super economy)	Network		5.544			
	Energy		7.330			
	SRES Cost Pass Through		0.036			
	Retail					
	Margin		0.780			
	Headroom		0.685			
	Total[b]		14.375			
Tariff 33 - Controlled supply (economy)	Network		10.061			
	Energy		8.760			
	SRES Cost Pass Through		0.036			
	Retail					

Retail tariff	Tariff component	Fixed charge[a]	Variable rate (flat)	Variable rate 1 (off-peak)	Variable rate 2 (shoulder)	Variable rate 3 (peak)
	Margin		1.140			
	Headroom		1.000			
	Total[b]		20.997			

a. Charged per metering point. b. Totals may not add due to rounding. c. These are the cost-reflective charges. d. These are the transitional charges customers will pay.

Table 22 Cost-reflective 2014–15 small customer regulated retail tariffs and unmetered supplies other than street lighting (GST exclusive) — carbon-inclusive

Retail tariff	Tariff component	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)	Network	80.500		13.432		
	Energy			10.082		
	SRES Cost Pass Through			0.036		
	Retail	45.626				
	Margin	7.624		1.424		
	Headroom	6.687		1.249		
	Total[b]	140.437		26.222		
Tariff 22 - Business (time of-use)	Network	80.500			9.240	15.240
	Energy				10.082	10.082
	SRES Cost Pass Through				0.036	0.036
	Retail	45.626				
	Margin	7.624			1.170	1.533
	Headroom	6.687			1.026	1.345
	Total[b]	140.437			21.555	28.236
Tariff 41 - Low voltage (demand)	Network	677.200	24.139	1.497		
	Energy			10.082		
	SRES Cost Pass Through			0.036		
	Retail	45.626				
	Margin	43.691	1.459	0.702		
	Headroom	38.326	1.280	0.616		
	Total[b]	804.843	26.878	12.933		
Tariff 91 - Unmetered	Network			10.061		
	Energy			10.082		
	SRES Cost Pass Through			0.036		
	Retail					
	Margin			1.220		
	Headroom			1.070		
	Total[b]			22.469		

a. Charged per metering point. b. Totals may not add due to rounding.

Table 23 Cost-reflective 2014–15 large customer regulated retail tariffs and street lighting (GST exclusive) — carbon-inclusive

Retail tariff	*Tariff component*	*Fixed charge*[a]	*Demand charge*	*Variable rate (flat)*
		c/day	*$/kW/month*	*c/kWh*
Tariff 44 - Over 100 MWh small (demand)	Network	4,436.774	34.589	1.767
	Energy			10.089
	SRES Cost Pass Through			0.038
	Retail	202.208		
	Margin	280.405	2.091	0.719
	Headroom	245.969	1.834	0.631
	Total[b]	5,165.356	38.514	13.244
Tariff 45 - Over 100 MWh medium (demand)	Network	14,892.378	31.035	1.767
	Energy			10.089
	SRES Cost Pass Through			0.038
	Retail	202.208		
	Margin	912.398	1.876	0.719
	Headroom	800.349	1.646	0.631
	Total[b]	16,807.334	34.556	13.244
Tariff 46 - Over 100 MWh large (demand)	Network	43,657.361	29.739	1.767
	Energy			10.089
	SRES Cost Pass Through			0.038
	Retail	202.208		
	Margin	2,651.109	1.798	0.719
	Headroom	2,325.534	1.577	0.631
	Total[b]	48,836.212	33.113	13.244
Tariff 47 - High voltage (demand)	Network	35,912.216	21.924	1.701
	Energy			9.535
	SRES Cost Pass Through			0.037
	Retail	202.208		
	Margin	2,182.950	1.325	0.681
	Headroom	1,914.869	1.162	0.598
	Total[b]	40,212.244	24.412	12.552
Tariff 48 – Over 4 GWh High voltage (demand)	Network	35,912.216	21.924	1.701
	Energy			9.535
	SRES Cost Pass Through			0.037
	Retail	577.059		
	Margin	2,205.608	1.325	0.681
	Headroom	1,934.744	1.162	0.598
	Total[b]	40,629.628	24.412	12.552
Tariff 71 - Street lighting[c]	Network	0.600		20.758
	Energy			10.089

Retail tariff	***Tariff component***	***Fixed charge[a]***	***Demand charge***	***Variable rate (flat)***
	SRES Cost Pass Through			0.038
	Retail			
	Margin	0.036		1.867
	Headroom	0.032		1.638
	Total[b]	0.668		34.390

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 F: BUILD-UP OF CARBON-EXCLUSIVE PRICES

Table 24 Residential regulated retail tariffs (GST exclusive) — carbon 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)[c]	Network	59.100	12.640			
	Energy		7.714			
	SRES Cost Pass Through		0.036			
	Retail	45.626				
	Margin	6.330	1.232			
	Headroom	5.553	1.081			
	Total[b]	116.609	22.703			
Transitional tariff 11[d]	Total[b]	83.414	25.378			
Tariff 12 - Residential (time of use)	Network	59.100		7.928	11.068	20.042
	Energy			7.714	7.714	7.714
	SRES Cost Pass Through			0.036	0.036	0.036
	Retail	45.626				
	Margin	6.330		0.948	1.137	1.680
	Headroom	5.553		0.831	0.998	1.474
	Total[b]	116.609		17.457	20.953	30.945
Tariff 13 - Residential (PeakSmart)	Network	59.100		5.956	10.802	19.560
	Energy			7.714	7.714	7.714
	SRES Cost Pass Through			0.036	0.036	0.036
	Retail	45.626				
	Margin	6.330		0.828	1.121	1.651
	Headroom	5.553		0.727	0.984	1.448
	Total[b]	116.609		15.261	20.657	30.409
Tariff 31 - Night rate (super economy)	Network		5.544			
	Energy		4.966			
	SRES Cost Pass Through		0.036			
	Retail					
	Margin		0.637			
	Headroom		0.559			
	Total[b]		11.743			
Tariff 33 - Controlled supply (economy)	Network		10.061			
	Energy		6.477			
	SRES Cost Pass Through		0.036			
	Retail					
	Margin		1.002			

Retail tariff	*Tariff component*	*Fixed charge[a]*	*Variable rate (flat)*	*Variable rate 1 (off-peak)*	*Variable rate 2 (shoulder)*	*Variable rate 3 (peak)*
	Headroom		0.879			
	Total[b]		18.454			

a. Charged per metering point. b. Totals may not add due to rounding. c. These are the cost-reflective charges. d. These are the transitional charges customers will pay.

Table 25 Cost-reflective 2014–15 small customer regulated retail tariffs and unmetered supplies other than street lighting (GST exclusive) — carbon-exclusive

Retail tariff	*Tariff component*	*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)	Network	80.500		13.432		
	Energy			7.714		
	SRES Cost Pass Through			0.036		
	Retail	45.626				
	Margin	7.624		1.280		
	Headroom	6.687		1.123		
	Total[b]	140.437		23.585		
Tariff 22 - Business (time of-use)	Network	80.500			9.240	15.240
	Energy				7.714	7.714
	SRES Cost Pass Through				0.036	0.036
	Retail	45.626				
	Margin	7.624			1.027	1.390
	Headroom	6.687			0.901	1.219
	Total[b]	140.437			18.918	25.598
Tariff 41 - Low voltage (demand)	Network	677.200	24.139	1.497		
	Energy			7.714		
	SRES Cost Pass Through			0.036		
	Retail	45.626				
	Margin	43.691	1.459	0.559		
	Headroom	38.326	1.280	0.490		
	Total[b]	804.843	26.878	10.296		
Tariff 91 - Unmetered	Network			10.061		
	Energy			7.714		
	SRES Cost Pass Through			0.036		
	Retail					
	Margin			1.077		
	Headroom			0.944		
	Total[b]			19.832		

a. Charged per metering point. b. Totals may not add due to rounding.

Table 26 Cost-reflective 2014–15 large customer regulated retail tariffs and street lighting (GST exclusive) — carbon-exclusive

Retail tariff	*Tariff component*	*Fixed charge*[a]	*Demand charge*	*Variable rate (flat)*
		c/day	*$/kW/month*	*c/kWh*
Tariff 44 - Over 100 MWh small (demand)	Network	4,436.774	34.589	1.767
	Energy			7.553
	SRES Cost Pass Through			0.038
	Retail	202.208		
	Margin	280.405	2.091	0.566
	Headroom	245.969	1.834	0.496
	Total[b]	5,165.356	38.514	10.421
Tariff 45 - Over 100 MWh medium (demand)	Network	14,892.378	31.035	1.767
	Energy			7.553
	SRES Cost Pass Through			0.038
	Retail	202.208		
	Margin	912.398	1.876	0.566
	Headroom	800.349	1.646	0.496
	Total[b]	16,807.334	34.556	10.421
Tariff 46 - Over 100 MWh large (demand)	Network	43,657.361	29.739	1.767
	Energy			7.553
	SRES Cost Pass Through			0.038
	Retail	202.208		
	Margin	2,651.109	1.798	0.566
	Headroom	2,325.534	1.577	0.496
	Total[b]	48,836.212	33.113	10.421
Tariff 47 - High voltage (demand)	Network	35,912.216	21.924	1.701
	Energy			7.139
	SRES Cost Pass Through			0.037
	Retail	202.208		
	Margin	2,182.950	1.325	0.537
	Headroom	1,914.869	1.162	0.471
	Total[b]	40,212.244	24.412	9.883
Tariff 48 – Over 4 GWh High voltage (demand)	Network	35,912.216	21.924	1.701
	Energy			7.139
	SRES Cost Pass Through			0.037
	Retail	577.059		
	Margin	2,205.608	1.325	0.537
	Headroom	1,934.744	1.162	0.471
	Total[b]	40,629.628	24.412	9.883
Tariff 71 - Street lighting[c]	Network	0.600		20.758
	Energy			7.553

Retail tariff	***Tariff component***	***Fixed charge[a]***	***Demand charge***	***Variable rate (flat)***
	SRES Cost Pass Through			0.038
	Retail			
	Margin	0.036		1.714
	Headroom	0.032		1.503
	Total[b]	0.668		31.566

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 G: CARBON-EXCLUSIVE PRICES FOR 2014-15

The following tables set out the QCA's Final Determination of regulated retail tariffs for 2014–15, exclusive of the impact of the carbon pricing mechanism. If the carbon tax is repealed, these will replace those provided in Chapter 7.

Table 27 2014–15 Regulated retail tariffs and prices for residential customers (GST exclusive) — carbon-exclusive

Retail tariff	*Energex network tariff*	*Fixed charge[a]*	*Variable rate (flat)*	*Variable*	*Variable*	*Variable*
				rate 1 (off-peak)	*rate 2 (shoulder)*	*rate 3 (peak)*
		c/day	*c/kWh*	*c/kWh*	*c/kWh*	*c/kWh*
Tariff 11 - Residential (flat rate)	8400	83.414	25.378			
Tariff 12 - Residential (time of use)	8900	116.609		17.457	20.953	30.945
Tariff 13 - Residential (PeakSmart)	7600	116.609		15.261	20.657	30.409
Tariff 31 - Night rate (super economy)	9000		11.743			
Tariff 33 - Controlled supply (economy)	9100		18.454			

a. Charged per metering point.

Table 28 2014–15 Regulated retail tariffs and prices for other small customers and unmetered supplies other than street lighting (GST exclusive) — carbon-exclusive

Retail tariff	*Energex network tariff*	*Fixed charge[a]*	*Demand*	*Variable rate*	*Variable rate*	*Variable rate*
			charge	*(flat)*	*(off-peak)*	*(peak)*
		c/day	*$/kW/month*	*c/kWh*	*c/kWh*	*c/kWh*
Tariff 20 - Business (flat rate)	8500	140.437		23.585		
Tariff 22 - Business (time of use)	8800	140.437			18.918	25.598
Tariff 41 - Low voltage(demand)	8300	804.843	26.878	10.296		
Tariff 91 - Unmetered	9600			19.832		

a. Charged per metering point.

Table 29 2014–15 Regulated retail tariffs and prices for large customers and street lighting (GST exclusive) — carbon-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	5,165.356	38.514	10.421
Tariff 45 - Over 100 MWh medium (demand)	EDMT1	16,807.334	34.556	10.421
Tariff 46 - Over 100 MWh large (demand)	EDLT1	48,836.212	33.113	10.421
Tariff 47 - High voltage (demand)	EDHT1	40,212.244	24.412	9.883
Tariff 48 – Over 4 GWh High voltage (demand)	EDHT1	40,629.628	24.412	9.883
Tariff 71 - Street lighting[b]	EVUT1	0.668		31.566

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

Table 30 2014–15 Transitional and obsolete regulated retail tariffs and prices (GST exclusive) — carbon-exclusive

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]		25.141	17.904		44.780				
Transitional tariffs for small customers and Ergon Energy large customers									
Tariff 21		61.538	41.818	39.291	29.911				
Tariff 22	151.652		40.902		14.403				
Tariff 62	66.468		39.411	33.328	13.936				
Tariff 65	66.468		31.438		17.316				
Tariff 66	146.493					16.478		31.957	96.085
Obsolete tariffs for large customers in Ergon Energy's network area									
Tariff 41(large)[a]	232.081					10.426	49.586		
Tariff 43(large)[a]	232.081		21.214		8.480		21.475		
Transitional tariffs for large customers in Ergon Energy's network area									
Tariff 20(large)	63.100					30.866			

a. New customers are not eligible for these retail tariffs.

b. Charged per metering point.

c. Tariff 21 – first 100kWh, tariff 22 – 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, tariff 65 – 12hr peak.

d. Tariff 21 – 101-10,000kWh, tariff 62 – 7am-9pm M-F over 10,000kWh.

e. Tariff 21 – over 10,000 kWh, tariff 22 – all other times, tariff 37 – 4:30pm-10:30pm, tariffs 43 (large), 62, & 65 – all other times.

APPENDIX H: GAZETTE NOTICE

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 2014, 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 alternative 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 30th day of May 2014.

Dr Malcolm Roberts, Chairman
Queensland Competition Authority

TARIFF SCHEDULE

Note 1: For the purposes of sections 55, 90, 91 and 91A of the Electricity Act, the tariffs and other retail fees and charges in this Tariff Schedule are exclusive of GST payable under the GST Act.

Note 2: This Tariff Schedule replaces the Tariff Schedule published in the Queensland Government Gazette on 24 June 2013.

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 daily to cover the costs of maintaining electricity supply to a premises, 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	**28.015 c/kWh**
plus a Service Fee per metering point per day of	**83.414 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)	**20.094 c/kWh**
Shoulder (7am-4pm), (8pm-10pm)	**23.590 c/kWh**
Peak (4pm-8pm)	**33.583 c/kWh**
Weekends:	
Off-Peak (10pm-7am)	**20.094 c/kWh**
Shoulder (7am-10pm)	**23.590 c/kWh**
plus a Service Fee per metering point per day of	**116.609 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 premises 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)	**17.898 c/kWh**
Shoulder (7am-4pm), (8pm-10pm)	**23.294 c/kWh**
Peak (4pm-8pm)	**33.046 c/kWh**
Weekends:	
Off-Peak (10pm-7am)	**17.898 c/kWh**
Shoulder (7am-10pm)	**23.294 c/kWh**

plus a Service Fee per metering point per day of **116.609 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 **26.222 c/kWh**

plus a Service Fee per metering point per day of **140.437 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 **28.236 c/kWh**

For electricity consumed at other times -

All Consumption **21.555 c/kWh**

plus a Service Fee per metering point per day of **140.437 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	**14.375 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	**20.997 c/kWh**

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

This tariff will be phased out no later than 30 June 2020. 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	**46.815 c/kWh**
For electricity consumed between the hours of 10.30 pm and 4.30 pm	**18.717 c/kWh**
Minimum Payment per day of	**26.283 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 –

$26.878 per kilowatt per month of chargeable demand.

Energy Charge –

All Consumption	**12.933 c/kWh**
plus a Service Fee per metering point per day of	**804.843 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 -

$52.020 per kilowatt per month of chargeable demand.

Energy Charge -

All Consumption	**10.938 c/kWh**
plus a Service Fee per metering point per day of	**243.474 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 –

$22.530 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	**22.255 c/kWh**

For electricity consumed at other times –

All Consumption	**8.896 c/kWh**
plus a Service Fee per metering point per day of	**243.474 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 per annum (Demand Small) – Ergon Energy Corporation Limited distribution area ONLY –**

This tariff is available to Ergon Energy Queensland Pty Ltd customers only.

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 - Large (SAC - Large) is a 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 –

$38.514 per kilowatt per month of chargeable demand.

Energy Charge –

All Consumption	**13.244 c/kWh**
plus a Service Fee per metering point per day of	**5165.356 c**

The chargeable demand charge in any month will be the kW amount by which a customer's metered monthly maximum demand is greater than the demand threshold applicable to the customer's network tariff. The demand threshold for Demand Small is 30 kW.

Where the monthly metered maximum demand is less than the demand threshold, the chargeable demand is set to zero and no demand charge is payable for that month.

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

Customers must have the appropriate metering installed in order to access this tariff.

***Tariff 45* – Business Over 100MWh per annum (Demand Medium) – Ergon Energy Corporation Limited distribution area ONLY –**

This tariff is available to Ergon Energy Queensland Pty Ltd customers only.

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 - Large (SAC - Large) is a 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 –

$34.556 per kilowatt per month of chargeable demand.

Energy Charge –

All Consumption	**13.244 c/kWh**
plus a Service Fee per metering point per day of	**16807.334 c**

The chargeable demand charge in any month will be the kW amount by which a customer's metered monthly maximum demand is greater than the demand threshold applicable to the customer's network tariff. The demand threshold for Demand Medium is 120 kW.

Where the monthly metered maximum demand is less than the demand threshold, the chargeable demand is set to zero and no demand charge is payable for that month.

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

Customers must have the appropriate metering installed in order to access this tariff.

***Tariff 46* – Business Over 100MWh per annum (Demand Large) – Ergon Energy Corporation Limited distribution area ONLY –**

This tariff is available to Ergon Energy Queensland Pty Ltd customers only.

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 - Large (SAC - Large) is a 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 –

$33.113 per kilowatt per month of chargeable demand.

Energy Charge –

All Consumption	**13.244 c/kWh**
plus a Service Fee per metering point per day of	**48836.212 c**

The chargeable demand charge in any month will be applied to the kW amount by which a customer's metered monthly maximum demand is greater than the demand threshold applicable to the customer's network tariff. The demand threshold for Demand Large is 400 kW.

Where the monthly metered maximum demand is less than the demand threshold, the chargeable demand is set to zero and no demand charge is payable for that month.

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

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 is available to Ergon Energy Queensland Pty Ltd customers only.

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 - Large (SAC - Large) is a 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 –

$24.412 per kilowatt per month of chargeable demand.

Energy Charge –

All Consumption	**12.552 c/kWh**
plus a Service Fee per metering point per day of	**40212.244 c**

The chargeable demand charge in any month will be applied to the kW amount by which a customer's metered monthly maximum demand is greater than the demand threshold applicable to the customer's network tariff. The demand threshold for Demand High Voltage General Supply is 400 kW.

Where the monthly metered maximum demand is less than the demand threshold, the chargeable demand is set to zero and no demand charge is payable for that month.

'Demand' shall mean the average demand in kilowatts over a period of 30 minutes, as measured on the distribution entity's meters. 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 is available to Ergon Energy Queensland Pty Ltd customers only.

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 –

$24.412 per kilowatt per month of chargeable demand.

Energy Charge –

All Consumption	**12.552 c/kWh**
plus a Service Fee per metering point per day of	**40629.628 c**

The chargeable demand charge in any month will be applied to the kW amount by which a customer's metered monthly maximum demand is greater than the demand threshold applicable to the customer's network tariff. The demand threshold for Business - General Supply (>4 Gigawatt Hours (GWh)) (Demand) is 400 kW.

Where the monthly metered maximum demand is less than the demand threshold, the chargeable demand is set to zero and no demand charge is payable for that month.

'Demand' shall mean the average demand in kilowatts over a period of 30 minutes, as measured on the distribution entity's meters. 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 alternative cost-reflective tariffs in the future. Transitional tariffs will be phased out no later than 30 June 2020.

Tariff 20 (Large) **– Business General Supply (Transitional) –**

This transitional tariff will be phased out no later than 30 June 2020, 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	**32.971 c/kWh**
plus a Service Fee per metering point per day of	**67.403 c**

Tariff 21 **– Business General Supply (Transitional) –**

This transitional tariff will be phased out no later than 30 June 2020.

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	**44.859 c/kWh**
Next 9,900 kilowatt hours per month	**42.148 c/kWh**
Remaining kilowatt hours per month	**32.087 c/kWh**
plus a Minimum Payment per day of	**66.014 c**

Tariff 22 (Small and Large) **– Business General Supply – Time-of-Use (Transitional) –**

This transitional tariff will be phased out no later than 30 June 2020.

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	**43.691 c/kWh**

For electricity consumed at other times -

All Consumption	**15.385 c/kWh**
plus a Service Fee per metering point per day of	**161.991 c**

Tariff 62 **- Farm - Time-of-Use (Transitional) -**

This transitional tariff will be phased out no later than 30 June 2020.

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	**41.202 c/kWh**
Remaining kilowatt hours	**34.843 c/kWh**

For electricity consumed at other times -

All Consumption	**14.569 c/kWh**
plus a Service Fee per metering point per day of	**69.489 c**

***Tariff 65* - Irrigation - Time-of-Use (Transitional) -**

This transitional tariff will be phased out no later than 30 June 2020.

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	**32.867 c/kWh**

For electricity consumed at other times –

All Consumption	**18.103 c/kWh**
plus a Service Fee per metering point per day of	**69.489 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 phased out no later than 30 June 2020.

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	**$33.410 per kW**
Remaining kilowatts	**$100.453 per kW**

Energy Charge –

All Consumption	**17.227 c/kWh**
plus a Service Fee per metering point per day of	**153.151 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	**34.390 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	**22.469 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:

$$Pa = \frac{P \times 12}{365.25} \times \text{days} \quad \text{for monthly charges}$$

$$Pa = \frac{P1}{365.25} \times \text{days} \quad \text{for annual charges}$$

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 (**28.015 cents/kWh**), plus a Service Fee of **83.414 cents** per day shall apply;
    (ii) for Tariff 31 (Night Rate – Super Economy), all consumption shall be charged at the 'All Consumption' rate (**14.375 cents/kWh**); and
    (iii) for Tariff 33 (Controlled Supply – Economy), all consumption shall be charged at the 'All Consumption' rate (**20.997 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) (**26.222 cents/kWh**), plus a Service Fee of **140.437 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 or Reimbursing 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 or reimbursed. 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 or reimbursement applies to all eligible fixed charges applicable to any account being used for pumping water for farm or irrigation purposes. The waiver or reimbursement 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.

Customers of other retail entities

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 fixed charge components as outlined in (A) above.

APPENDIX I: ASSUMPTIONS USED TO DETERMINE CUSTOMER IMPACTS

Table 31 Tariff Assumptions

Retail tariff	*Tariff Type*	*Consumption kWh per annum*	*Demand Threshold (kWh/month)*	*Demand kW per month*	*Peak*	*Shoulder*	*Off Peak*
Tariff 11	Residential (flat rate)	4,100					
Tariff 12[1]	Residential (time-of-use)	11,000			19%	54%	26%
Tariff 13[1]	Residential (PeakSmart)	11,000			19%	54%	26%
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	30	54			
Tariff 45	Large business (demand medium)	785,260	120	206			
Tariff 46	Large business (demand large)	2,422,237	400	518			

Sources: Energex and Ergon Energy.

[1] The split between peak, shoulder and off-peak for Tariffs 12 and 13 have been updated, on advice from Energex. The change will affect estimates of a 'typical' tariff 12 or 13 customer bill, including the percentage change from 2013-14 to 2014-15.

APPENDIX J: SRES COST PASS-THROUGH CALCULATIONS

This appendix provides further information about how the SRES pass-through amounts in Chapter 5 were calculated.

Firstly, we recalculated the actual cost of SRES compliance during 2013–14, in cents per kilowatt hour (c/kWh), based on the binding STP target for the 2014 calendar year. We then subtracted the SRES cost included in 2013–14 notified prices from the actual cost. This resulted in an under-recovery of 0.03 c/kWh, as shown in Table 32.

Table 32 2013-14 SRES under-recovery for all settlement classes ($2013-14)

	Period	*STP (%)*[1]		*Clearing House Price*[1] *($/MWh)*	*SRES Cost ($/MWh)*	*Average 2013-14 SRES cost (c/kWh)*
		Binding	*Non-binding*			
2013-14 Final Determination	1 Jul - 31 Dec 2013	19.70%		$40.00	$7.88	0.574
	1 Jan - 30 Jun 2014		8.98%	$40.00	$3.59	
2013-14 Actual	1 Jul - 31 Dec 2013	19.70%		$40.00	$7.88	0.604
	1 Jan- 30 Jun 2014	10.48%		$40.00	$4.19	
Under-recovery						**0.030**

1. Published by the Clean Energy Regulator

Next, we made an adjustment to account for network losses. In the 2013-14 Determination, we applied three different loss factors to energy purchase costs to reflect transmission and distribution (network) losses for each settlement class to determine the liabilities based on energy acquired. We applied the same network loss factors to the under-recovered SRES amounts calculated above, consistent with the 2013-14 Determination.

We then made an adjustment to restore the real values of the under-recovered amounts by applying the forecast change in the CPI for the year ended June 2015 of 2.75%[50] and an adjustment to reflect the time-value of money for retailers over that 12-month period, by applying a real weighted average cost of capital (WACC) of 9.7%. The WACC used is consistent with the range of estimates of retailers' WACC that were used (in conjunction with two other methods) to set the retail margin that we have applied[51]. Finally, we applied the retail margin of 6%[52] and a headroom allowance of 5% to arrive at the final SRES pass-through amounts.

A summary of the calculations and pass-through amounts by settlement class is provided in Table 33.

[50] This is consistent with the mid-range of the RBA forecast of 2.25-3.25% for the 12 months to 30 June 2015. Reserve Bank of Australia, *Statement on Monetary Policy*, February 2014.

[51] As discussed in Chapter 4, we continue to use a benchmarking approach to set the retail margin. As a result, for this exercise, we have not undertaken a bottom-up assessment of the retail margin or retailers' WACC.

[52] A retail margin of 6% of total costs (excluding the margin) is equivalent to a retail margin of 5.7% of total costs (including the margin).

Table 33 SRES pass-through amounts by settlement class (after adjustments for network losses, CPI, WACC, margin and headroom)

Energex NSLP, Unmetered Supply, Controlled Load 9000 and 9100	
SRES under-recovery (2013-14 c/kWh)	0.03
+ Energy losses (%)	7.30%
+ CPI (%)	2.75%
+ Real WACC (%)	9.70%
Total under-recovery before application of retail margin and headroom ($2014-15 c/kWh)	0.036
+ Retail Margin (%)	6%
+ Headroom allowance (%)	5%
SRES pass-through (c/kWh)	0.040
Ergon Energy NSLP - SAC Demand and Street Lighting	
SRES under-recovery (2013-14 c/kWh)	0.03
+ Energy losses (%)	13.5%
+ CPI (%)	2.75%
+ Real WACC (%)	9.70%
Total under-recovery before application of retail margin and headroom ($2014-15 c/kWh)	0.038
+ Retail Margin (%)	6%
+ Headroom allowance (%)	5%
SRES pass-through (c/kWh)	0.043
Ergon Energy NSLP - SAC HV, CAC and ICC	
SRES under-recovery (2013-14 c/kWh)	0.030
+ Energy losses (%)	8.80%
+ CPI (%)	2.75%
+ Real WACC (%)	9.70%
Total under-recovery before application of retail margin and headroom ($2014-15 c/kWh)	0.037
+ Retail Margin (%)	6%
+ Headroom allowance (%)	5%
SRES pass-through (c/kWh)	0.041